EB-2018-0329

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, SO 1998, c. 15 (Sched B), as amended (the "**Act**") and the *Municipal Franchises Act* (the "**MFA**"), RSO 1990, c. M.55, as amended;

AND IN THE MATTER OF an application by the Corporation of the Town of Marathon under section 8 of the MFA for an order or orders granting Certificates of Public Convenience and Necessity to the Corporation for the construction of works in the Town of Marathon, Township of Manitouwadge, Township of Schreiber, Township of Terrace Bay, and Municipality of Wawa;

AND IN THE MATTER OF an application by the Corporation of the Town of Marathon under section 90 of the Act for an order or orders granting leave to construct natural gas distribution pipelines and ancillary facilities to serve the Town of Marathon, Township of Manitouwadge, Township of Schreiber, Township of Terrace Bay, and Municipality of Wawa;

AND IN THE MATTER OF an application by the Corporation of the Town of Marathon under section 97 of the Act for an order or orders approving the form of easement agreements;

AND IN THE MATTER OF an application by the Corporation of the Town of Marathon for an order or orders for a gas supply plan to serve the Town of Marathon, Township of Manitouwadge, Township of Schreiber, Township of Terrace Bay, and Municipality of Wawa;

AND IN THE MATTER OF an application by the Corporation of the Town of Marathon for an order or orders pre-approving the cost consequences associated with a long-term upstream liquefied natural gas contract to serve the Town of Marathon, Township of Manitouwadge, Township of Schreiber, Township of Terrace Bay, and Municipality of Wawa.

Nipigon LNG Corporation ("Nipigon LNG" or "NLNG") in its capacity as the general partner of Nipigon LNG LP

Written Final Submission

January 6, 2020

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I. INTRODUCTION

1. The Corporation of the Town of Marathon ("**Corporation**" or **"Applicant**"), in its own capacity and as the representative of the Township of Manitouwadge, the Township of Schreiber, the Township of Terrace Bay and the Municipality of Wawa (together, the "**Municipalities**"), has made the within application ("**Application**") to the Ontario Energy Board (the "**Board**" or "**OEB**") in respect of a project to develop, construct, own and operate a regional natural gas distribution pipeline system to supply gas to their communities in Northern Ontario (the "**Project**").

2. Nipigon LNG is a partnership constructing strategic liquefied natural gas ("**LNG**") infrastructure in Northern Ontario to reduce energy costs and support economic development in the region. Specifically, Nipigon LNG is building and will operate a liquefaction and storage facility located in the unincorporated Township of Ledger, tying directly into the TC Energy Mainline with a connecting pipeline (the "**LNG Facilities**").

3. Nipigon LNG and its parent company, Northeast Midstream LP, have engaged collaboratively with the Corporation since the inception of the Project regarding gas supply to the Municipalities and has supported the Corporation's efforts to assess, plan, and develop a greenfield regional gas distribution system to serve the Municipalities.

4. As a critical component of the Project, Nipigon LNG will be constructing and maintaining LNG storage and regasification depots located in each of the five Municipalities (the "**LNG Depots**").

5. Nipigon LNG will deliver LNG through truck transport from the LNG Facilities to the LNG Depots located within the Municipalities. One LNG Depot will be located in each Municipality and will supply natural gas directly into the local distribution system within each Municipality (the "**Distribution Systems**"). LNG is the preferred natural gas supply option contemplated by the Applicant for the Distribution Systems.

6. To ensure service, reliability, costs, and recoverability of capital cost over the long-term of the Project, Nipigon LNG and the Corporation have drafted an LNG Services Agreement (the "**LNG Services Agreement**").[1] The LNG Services Agreement, if pre-approved, will be finalized and entered into between Nipigon LNG and a utility that will be formed by the Corporation and the Municipalities (the "**Utility**").

7. Upon application in these proceedings, Nipigon LNG has been granted intervenor status by the OEB.[2] The Board stated:

> The Town of Marathon has applied for approval of a long-term gas supply plan to serve each Municipality, and for pre-approval of the cost

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[1] EB-2018-0329 Corporation of the Town of Marathon North Shore LNG Project Application, Exhibit A, Tab 13, Schedule 1, Attachment 5. [Application]

[2] OEB Procedural Order No. 2, issued October 30, 2019. [Procedural Order No. 2]

consequences of a ten year liquefied natural gas supply contract. The OEB would be assisted by the consideration of possible alternatives for the proposed gas supply plan and gas supply contract. The interventions of NLNG and Certarus are accepted on these issues only.[3]

8. Nipigon LNG submits that alternatives to the proposed Initial Gas Supply Plan applicable to the Project (the "**Gas Supply Plan**") and LNG Services Agreement have been thoroughly considered by the Corporation and the Municipalities prior to the filing of the Application. The assessment of viability has been a years-long process, vigorously considering all alternatives and developing a competitive, economical, and adaptive delivery system to meet the unique needs of the Municipalities and potentially other communities of the North Shore.

9. Nipigon LNG makes these submissions in support of the Application and the relief sought by the Applicant.

II. RELIEF SOUGHT

10. Nipigon LNG supports the Application and the relief sought by the Applicant.[4] Including, specifically:

    a. An order or orders under section 36 of the *Ontario Energy Board Act,* SO 1998, c. 15, Sch. B. (the "**Act**")[5], pre-approving for the purpose of setting the distribution rates of the Utility, the Utility's Gas Supply Plan and the cost consequences of the long-term LNG Services Agreement proposed to be entered into by Nipigon LNG and the Utility.[6]

11. Nipigon LNG requires pre-approval of the cost consequences of the LNG Services Agreement in order to provide Nipigon LNG with the assurance it requires to make the financial commitment to construct the proposed LNG Depots in each Municipality. Without pre-approval of the cost consequences of the LNG Services Agreement, Nipigon LNG could not commit to build and operate the proposed LNG Depots in each Municipality, and the Applicant would not have access to the most cost-effective and reliable gas supply to meet its forecasted delivery requirements.

12. Further, Nipigon LNG submits that Certarus Ltd. ("**Certarus**"), an intervenor in these proceedings, is attempting to provide improper input into these proceedings, and its

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[3] *Ibid.*
[4] EB-2018-0329 Town of Marathon's Argument-in-Chief, Filed 2019-12-11, at paragraphs 3-13. [Marathon Argument]
[5] *Ontario Energy Board Act,* SO 1998, c. 15, Sch. B.
[6] Marathon Argument, at paragraph 3(iv).

submissions ought to be disregarded by the Board to the extent that they impair or otherwise hinder the ability of the Applicant to proceed with the Project.

III. PRE-APPROVAL OF COST CONSEQUENCES OF LNG SERVICES AGREEMENT

(a) Test for Pre-Approval

13. The Corporation, on its own behalf and on behalf of the Municipalities, seeks pre-approval for the LNG Services Agreement pursuant to section 36 of the Act and the OEB's Filing Guidelines for Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contract (the "**Guidelines**").[7]

14. The approvals sought by the Applicant will be transferred, as required, to the as yet to be formed Utility contemplated by the Corporation and the Municipalities. Once the relief sought in the Application is granted, the Utility will be formed.

15. Nipigon LNG repeats and adopts the submissions contained in the Application, as well as the Argument-in-Chief of the Corporation of the Town of Marathon ("**Marathon Argument**").

16. Consideration for pre-approval of a long-term natural gas supply contract under section 36 of the Act is informed by the requirements of the Guidelines, which set out a two-part test for obtaining pre-approval of the cost consequences of a long-term contract:

    a. To be eligible for pre-approval, the contemplated contract must be a long-term natural gas supply contract supporting the development of new infrastructure; and

    b. If eligible, the OEB must then determine whether the contract should be pre-approved, by considering the non-exhaustive criteria of:

        i. Need, Costs, and Benefits of the project;

        ii. Contract Diversity; and

        iii. Risk Assessment. [8]

17. The eligibility threshold is clearly satisfied by the parameters of the LNG Services Agreement. The Project will create a new source of natural gas supply to the Municipalities

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[7] *Filing Guidelines for Pre-Approval of Long-term Natural Gas Supply and/or Upstream Transportation Contracts* dated April 23, 2009. [Guidelines] **[TAB 1]**

[8] Guidelines, *supra;* Union Gas Limited, Enbridge Gas Distribution Inc., Application for Pre-Approval of the Cost Consequences of Long-Term Natural Gas Transportation Contracts for Capacity on the NEXUS Pipeline, Decision and Order dated December 17, 2015, EB-2015-0166 / EB-2015-0175 [NEXUS Decision] at page 7. **[TAB 2]**

from the TC Energy Mainline. The ability to provide a natural gas supply to previously unserved communities or areas is a key factor in the consideration for pre-approval by the Board.[9] Nipigon LNG repeats and adopts the submissions of the Corporation that the LNG Services Agreement is long-term by any definition, particularly with regard to the 10-year term with the option to renew the term for 10 further years.[10]

18. Pre-approval is appropriate and required in these circumstances, as it would be unreasonable for Nipigon LNG to assume the risk of building the required infrastructure or agree to a 10-year contract (with a renewal option) without the certainty arising from pre-approval.[11] Further, the Corporation indicated that the Utility's investors will not provide the capital required to finance the Utility without pre-approval of the cost consequences of the LNG Services Agreement.[12]

19. Nipigon LNG submits that the eligibility criteria of the LNG Services Agreement for pre-approval are clearly met and agrees with the Marathon Argument in this respect.

20. In terms of assessing the second part of the test for pre-approval, it is not necessary to convince the OEB that there are no alternatives to the Project and the LNG Services Agreement. It is sufficient for the OEB to assess the benefits that will accrue to customers against the costs to customers.[13] This threshold for assessing pre-approval of a contract is important in light of the submissions of intervenors in this matter. Nipigon LNG submits that while there may be alternative sources of natural gas available, they do not adequately meet the needs of the Municipalities to the same degree of cost-effectiveness and reliability demonstrated by the Project and the LNG Services Agreement.

21. The Corporation and the Municipalities have performed significant front-end work to assess all available options before determining which supply source to proceed with. The alternative supplies of natural gas and the efforts of the Corporation to review and assess same are detailed later in this submission.

22. The need for the Project and LNG Services Agreement is clear. The residents, businesses, and institutions of the Municipalities and surrounding areas do not currently have access to natural gas.[14] Nipigon LNG's innovative solution for natural gas supply and delivery in

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[9] NEXUS Decision, *supra*, at page 10, where the Board stated: The OEB finds that the key factor is whether the infrastructure is new, not whether the source of gas supply is new. **[TAB 2]**
[10] Marathon Argument, at paragraph 78.
[11] Enbridge Gas Distribution Inc. (Re), 2014 LNONOEB 41, January 30, 2014, Nos. EB-2012-0433 / EB-2012-0451, / EB-2013-0074, at para 49: The Board found that even Union Gas Limited was able to rely on the need for pre-approval as a pre-condition to entering a long-term transportation contract. **[TAB 3]**
[12] Marathon Argument, at paragraph 13.
[13] NEXUS Decision, *supra*, at page 14. **[TAB 2]**
[14] Application, Exhibit A, Tab 2, Schedule 1, page 2.

remote locations in Northern Ontario is able to competitively supply the consumer base with natural gas.

23. As shown by the preliminary survey and market analysis contained in the Application, there is a clear need and benefit to the consumers in the Municipalities. Not only has the Project been thoroughly reviewed for need and benefit, it is a community backed and endorsed endeavour.[15]

24. The economic benefits of the Project and LNG Services Agreement are detailed in the Application. In addition, the use of LNG as a natural gas source provides further benefits that extend beyond price-point savings, including:

    a. Low carbon emissions;

    b. Low energy cost; and

    c. Reliability.[16]

25. These factors are of considerable benefit to the Municipalities and are in the public interest over the proposed term of the LNG Services Agreement.

26. Nipigon LNG agrees with the submissions of the Applicant that the requirements of contract diversity are met through the adoption of the LNG Services Agreement.[17] Further, any concerns regarding the reliance of the Utility on a single contract during the initial term of the LNG Services Agreement are adequately addressed through the risk management efforts proposed by the Applicant and Nipigon LNG.

27. Aspects of the LNG Services Agreement that mitigate risk to the Utility and the consumer include:

    a. Phase-based increase of capacity over the term of the LNG Services Agreement;

    b. Flexibility in respect of the renewal option subsequent to the initial 10-year term; and

    c. Nipigon LNG is committed to a fixed capacity charge based on the forecasts provided in the Application. Accordingly, the Utility is not exposed to capital cost

[15] Application, Exhibit A, Tab 2, Schedule 1, page 3.
[16] Application, Exhibit A, Tab 13, Schedule 1, at page 10.
[17] Application, Exhibit A, Tab 13, Schedule 1, at pages 14-15.

overruns incurred by Nipigon LNG during the term of the LNG Services Agreement.[18]

28. Further, the LNG Services Agreement contains no provisions that preclude the Utility from contracting for other sources of natural gas supply.[19]

(b) The LNG Services Agreement is Consistent with Similar Contracts Approved by the Board

29. The Board has previously determined that similar methods of addressing capital cost overruns through the form and provisions of relevant agreements have provided adequate risk mitigation when considering pre-approval of a long-term contract.[20]

30. The Applicant is proposing that the Utility contract with Nipigon LNG under a fixed-term, fixed-priced agreement, subject to certain indexing arrangements, to liquefy a specified quantity of natural gas, to store five days of peak demand of natural gas within each of the five Municipalities (seven days for Wawa), and to deliver LNG into the five independent delivery points of the Distribution Systems. As part of the agreement, the Utility will acquire capacity on a firm daily basis, and pay as follows:

  a. Firm capacity charge per gigajoule ("**GJ**") of reserved capacity, payable whether or not production is nominated. The firm capacity charge is fixed in Schedule B of the LNG Services Agreement, and includes a provision for escalation (the "**Firm Capacity Charge**"). The first-year Firm Capacity Charge for Nipigon LNG is to be $7.03 per GJ per day;[21]

  b. Variable charge per GJ of LNG produced and delivered. The charge comprises the customer's pro rata share of consumables used to produce and deliver LNG and is described in section 4 of the LNG Services Agreement (the "**Variable Charge**").[22] The Variable Charge is estimated to be approximately $0.44 per GJ in the first year. The Variable Charge reflects the actual cost of electricity, nitrogen, natural gas and other items consumed in the liquefaction and regasification process. The Variable Charge is passed through to the customer without markup or profit; and

  c. Transportation charges for the fuel and operating costs to transport LNG from the LNG Facilities to the LNG Depots in each Municipality. Nipigon LNG will provide the trucking, with the actual cost passed through to the Utility without markup or profit. LNG trucking has an excellent safety record and is regulated by Transport

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[18] Application, Exhibit A, Tab 1, Schedule 2, at pages 7-8.
[19] EB-2018-0329, Corporation of the Town of Marathon Responses to Certarus Ltd. Interrogatories, Filed 2019-11-26, at Interrogatory 13(a). [Responses to Certarus Interrogatories]
[20] NEXUS Decision, *supra*, at page 18. **[TAB 2]**
[21] Application, Exhibit A, Tab 13, Schedule 1, Attachment 5, page 37.
[22] Application, Exhibit A, Tab 13, Schedule 1, Attachment 5, page 16.

Canada. The current estimated cost to transport LNG from the LNG Facilities to the LNG Depots is approximately $0.84 per GJ on a weighted average basis.

31. These types of charges and the proposed fee structure in the LNG Services Agreement are consistent with the types of charges and fee structure contained in the contracts submitted by Union Gas Limited and Enbridge Gas Distribution Inc. and approved by the Board for capacity on the NEXUS Decision, referred to above.

32. Accordingly, Nipigon LNG submits that the LNG Services Agreement is eligible for, and ought to receive, pre-approval from the Board, as sought by the Applicant. Additional considerations regarding the Gas Supply Plan and comparison of the services provided under the LNG Services Agreement are further detailed below.

(c) Planning, Assessment, and Guiding Principles of Gas Supply Plan

33. The OEB has stated in Procedural Order No. 2 that it would be assisted by consideration of possible alternatives to the proposed Gas Supply Plan and LNG Services Agreement.[23] The Corporation and Municipalities performed considerable review and assessment in respect of alternative energy or natural gas delivery sources during the planning stages of the Application.

34. Beginning in 2015, Nipigon LNG, through its parent company Northeast Midstream LP, collaborated with the Municipalities to develop a natural gas supply solution that would provide natural gas to the previously unserved communities, including the Municipalities.

35. This solution-oriented development process to design a greenfield supply system capable of providing natural gas services involved a comprehensive feasibility study in part supported by an application to the Northern Ontario Heritage Fund Corporation ("**NOHFC**") for funding (the "**Feasibility Study**").[24]

36. The Feasibility Study included input from a number of parties, including design and engineering support from Cornerstone Energy Services ("**Cornerstone**") and market information and demand forecasting by Elenchus Research Associates Inc. ("**Elenchus**"). Both Cornerstone and Elenchus have extensive experience in greenfield natural gas projects.[25]

[23] Procedural Order No. 2, *supra*.
[24] Application, Exhibit A, Tab 9, Schedule 4, page 1.
[25] Application, Exhibit A, Tab 3, Schedule 1, page 2.

37. Upon receipt and review of the Feasibility Study, NOHFC awarded a grant of $3,453,443.00 to the Corporation in respect of the Project.[26] The Corporation then enlisted the professional services of Elenchus to begin work on the Gas Supply Plan.[27]

38. Guiding principles of the Applicant's Gas Supply Plan, as mandated by the OEB's Framework for the Assessment of Distributor Gas Supply Plans (the "**Framework**"), are:

   a. Cost-effectiveness;

   b. Reliability and security of supply; and

   c. Public policy initiatives.[28]

39. The Framework clarifies the consideration of the above principles, stating:

> For clarity, <u>cost-effectiveness does not necessarily mean the "lowest cost," reliability does not mean "reliable at any cost"</u> and support for public policy does not mean "support at any cost" or "any level of reliability." Rather, the intent is to strike a balanced approach to the benefit of customers.[29] (Emphasis added)

40. The Corporation explored several alternatives during the initial discovery and exploratory phase of assessing the potential for a natural gas project. Representatives of the Corporation and the Municipalities held meetings and discussions with alternative natural gas service suppliers. These discussions were independent from, and did not include, representatives of Nipigon LNG.[30]

41. The Applicant assessed several gas supply alternatives according to their cost-effectiveness, reliability (including security of supply), and support for public policy, including:

   a. Connecting the Municipalities to the TC Energy Mainline through a lateral natural gas pipeline expansion, which was ruled out due to the high capital costs and inability of the markets to support the capital costs required;[31]

   b. Compressed natural gas ("**CNG**") as an alternative source to LNG, which is detailed further below; and

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[26] Application, Exhibit A, Tab 9, Schedule 4, Attachment 2.
[27] Application, Exhibit A, Tab 8, Schedule 1, Attachment 1.
[28] Application, Exhibit A, Tab 8, Schedule 1, Attachment 1, at page 6.
[29] Framework for the Assessment of Distributor Gas Supply Plans, EB-2017-0129; Report of the Ontario Energy Board, issued October 25, 2018 at page 8. [Framework] **[TAB 4]**
[30] Response to Certarus Interrogatories, at Interrogatory 3.
[31] Application, Exhibit A, Tab 13, Schedule 1, page 10-11.

c. Alternative sources of LNG.

Compressed Natural Gas

42. Importantly, and in light of the assertions contained in the intervention request and interrogatories of Certarus, CNG was reviewed and considered as a supply option. For the reasons detailed below, the Corporation determined that LNG from the proposed LNG Facilities near Nipigon in the unincorporated Township of Ledger was the preferred supply option, based on several factors, including cost advantages, benefits to the consumers, and reliability of deliverables with respect to the specific challenges facing the Project.[32]

43. Specifically, based on a landed cost analysis, the Corporation determined that CNG was less viable than LNG. While the two forms of natural gas would be operationally similar, including connection to upstream sources, requiring processing facilities, and truck-based transport, the nature of CNG makes it more costly to ship and store.

44. CNG, due to its lower energy density when compared to LNG, requires:

    a. Additional storage costs; and

    b. Approximately 250% more truck deliveries per day.[33]

45. Not only do the additional storage costs and higher number of truck deliveries associated with CNG increase the landed cost of CNG when compared to LNG; LNG is also a far more reliable source of natural gas given the logistical realities of the Municipalities, and with particular regard to the challenges of delivering and storing gas in the winter months.[34]

46. As in the NEXUS Decision, the Applicant in these proceedings has conducted a landed cost analysis and provided the methodologies and assumptions, which resulted in identified outcomes for the landed costs of the alternatives.

47. Nipigon LNG further submits that the Applicant's estimates included in the landed cost analysis of CNG as an alternative supply option likely understate the actual landed costs, given that the assumed weighted average cost of capital is 6% and the amortization term is 20 years, which are conservative estimates for such an investment.[35] Nipigon LNG recognizes that there is always a level of uncertainty with capital cost estimates yet is satisfied that the analyses support the Applicant's position that the LNG Services Agreement is cost-competitive.

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[32] Application, Exhibit A, Tab 2, Schedule 2, pages 2-3.
[33] Application, Exhibit A, Tab 13, Schedule 1, page 13-14.
[34] *Ibid*.; See also EB-2018-0329, Corporation of the Town of Marathon's Responses to OEB Staff Interrogatories, Filed 2019-11-26, at Integratory 11. [Responses to OEB Staff Interrogatories]
[35] Responses to OEB Staff Interrogatories, at Interrogatory 11(a), Attachments A1 - A3.

48. Further considerations regarding the assertions contained in Certarus' intervenor request and written interrogatories are detailed below. Nipigon LNG submits that it is necessary that the Board give full weight to the fact that the Applicant indeed considered CNG as an alternative supply of natural gas and determined that CNG was not a viable option, for the detailed reasons contained in the Application materials and the Corporation's response to interrogatories.

Alternative LNG Options

49. The review of alternative gas supply options provided the Applicant sufficient certainty that LNG is the most cost-effective and reliable source of natural gas. The Applicant also considered LNG supply from sources other than Nipigon LNG. These sources included alternative supply points in Minneapolis and Montreal, which the Applicant determined were not feasible based on the considerably longer transport distance required and the corresponding increase in transport cost compared to Nipigon LNG. This resulted in the landed costs associated with delivery of LNG from alternative sources to be uneconomical even when compared to the landed costs of CNG as identified in the Application.[36]

50. Additionally, the Applicant considered LNG deliverables from closer sources, including Enbridge Gas Inc.'s ("**Enbridge**") facility in Hagar, Ontario. However, Enbridge's services can only be provided on an interruptible basis, rather than the firm basis offered by Nipigon LNG.[37] The Applicant determined that the lack of firm supply was a key consideration, as an interruptible LNG supply would directly impact the reliability of services provided to the consumer base.

(d) Additional Benefits of LNG-Based Supply

LNG Has a Proven Track Record of Cost-Effectiveness, Reliability, and Safety When Used by Local Distribution Companies

51. OEB Staff requested references to at least three case studies that demonstrate the success of the LNG virtual pipeline distribution model in other markets.[38] The Applicant's response included facilities owned by multiple local distribution companies ("**LDCs**") in New England, most of which were first built in the 1960s and 1970s to provide consumers with a cost-effective and reliable alternative to pipeline natural gas during times of peak demand.[39]

52. To put the New England case in context, all New England LDCs combined have a liquefaction capacity of approximately 43,000 GJ per day, LNG storage capacity of

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[36] Marathon Argument, at paragraphs 90-92.
[37] *Ibid*., at paras 93-94.
[38] EB-2018-0329, OEB Staff Interrogatories, November 8, 2019, at Interrogatory 10. [OEB Staff Interrogatories]
[39] Responses to OEB Staff Interrogatories, at Interrogatory 10.

approximately 16 Petajoules ("**PJ**") (which does not include the storage at the Everett LNG terminal) and 3 PJ per day of vaporization capacity.[40] The scope and scale of the New England facilities, which have been delivering natural gas cost-effectively, reliably, and safely for decades, far exceed the capacity proposed under the LNG Services Agreement.

53. LNG plays a critical role in gas supply portfolios of natural gas LDCs across North America, including LDCs in Ontario, Quebec, and British Columbia. No other alternative to natural gas pipelines, including CNG, has the demonstrated scope, scale, or operating history of LNG in LDC applications.

LNG Storage is Physically and Permanently Attached to the Distribution Systems in Sufficient Quantities

54. To mitigate risk of disruption to the gas supply chain, the Applicant is proposing to store five days of peak demand of natural gas within each Municipality (and seven days of storage for Wawa). In addition, Nipigon LNG can confirm it will provide for an extra three to four days of LNG produced, held in large tanks at the LNG Facilities near Nipigon, and ready to deliver to the Applicant, which affords the Applicant with additional resiliency and security of supply.

55. Nipigon LNG submits that the proposed provisions in the Gas Supply Plan for storage physically attached to the Distribution Systems at any time are prudent, reasonable and in the public interest.[41] A smaller amount of attached storage could critically increase the risk of curtailments or interruptions in delivery services, especially during periods of peak demand in winter. For example, the loss of gas pressure may cause pilot lights on furnaces and water heaters to go out unexpectedly. In such a case, the Applicant would need to go door-to-door, check every customer's equipment, and relight extinguished pilot lights, all of which is a costly and resource-intensive activity.

56. It is certainly possible for Nipigon LNG to provide more storage at the LNG Depots or the LNG Facilities, if more reliability is deemed necessary by the Board or the Applicant. Storage is modular and can be added easily. Any additional cost to facilitate additional storage dedicated to the Project would require Nipigon LNG to adjust the Firm Capacity Charge.[42]

The Applicant has Flexibility to Access Alternative Gas Supplies if/when Necessary

57. For supply disruptions of a longer duration, Nipigon LNG agrees that it is possible to originate alternative natural gas supplies, including LNG from Minneapolis or Montreal or CNG from Red Rock or Timmins. All these gas supply options are technically

[40] Northeast Gas Association, "The Role of LNG in the Northeast Natural Gas (and Energy) Market." https://www.northeastgas.org/about_lng.php **[TAB 5]**
[41] Application, Exhibit A, Tab 8, Schedule 1, Attachment 1, pages 6-7.
[42] Responses to OEB Staff Interrogatories, at Interrogatory 32.

interchangeable with LNG supplied and delivered under the LNG Services Agreement and would not impact combustion performance at the burner tip.

58. As for forecasting risks and the contracted demand under the LNG Services Agreement, the Applicant's contracted demand ramps up over the 10-year term, as attachments grow. If alternatives and/or lower priced gas supply and transportation options become available at some point in the 10-year term of the LNG Services Agreement, the Applicant has flexibility to take advantage of those opportunities to meet any incremental loads.

IV. NIPIGON LNG FACILITY CONSTRUCTION AND OPERATION

59. In determining whether the availability of alternative gas supply plans or contracts should impact the Board's review of the Application, it is important for the Board to consider the significant procedural and regulatory steps that Nipigon LNG has undertaken and completed in respect of the Project.

60. The viability of the LNG Services Agreement is predicated on the ability of Nipigon LNG to tie into and obtain natural gas from the TC Energy Mainline. In furtherance of the operational ability to do so, Nipigon LNG has engaged in proceedings before the National Energy Board (now Canada Energy Regulator, referred to herein as "**NEB**") and the OEB in respect of the approval and construction of the LNG Facilities.

61. These steps include:

    a. Entering into a commercial backstopping agreement with TC Energy Corporation ("**TC Energy**") in respect of constructing the necessary facilities to tie into the TC Energy Mainline, which agreement has been approved in principle by the NEB; and

    b. Obtaining a certificate of public convenience in respect of the LNG Facilities located in the unincorporated Township of Ledger.

62. These steps provide certainty and reliability that Nipigon LNG will be able to meet the schedule and demands of the Project. Particulars of these efforts are detailed below.

(a) TC Energy Backstopping Agreement

63. At the time of filing, Nipigon LNG has entered into a commercial backstopping agreement with TC Energy for the design, construction, and commissioning of the requisite facility prior to the commissions and start-up of the LNG Facilities (the "**TC Energy Backstopping Agreement**").[43]

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[43] Responses to OEB Staff Interrogatories, at Interrogatory 29(a).

64. The NEB determined that the TC Energy Backstopping Agreement is the most appropriate way to advance the interconnection between the TC Energy Mainline and the LNG Facilities in Ledger, and determined that no further order was required.[44]

65. Nipigon LNG and TC Energy are currently engaged in the necessary work and obtainment of relevant regulatory approvals to ensure that the requirements of the Corporation and the Utility will be met, as stipulated in the LNG Services Agreement.

66. Nipigon LNG agrees with the assessment of the Corporation that the risk that the NEB will fail to provide required approvals in respect of the interconnection between the TC Energy Mainline and the LNG Facilities is very low.[45]

(b) Nipigon LNG Facilities and OEB Approval

67. On November 18, 2018, the Board granted in favour of Nipigon LNG's Application for a certificate of public convenience and necessity to construct works to supply natural gas in the unincorporated Township of Ledger.[46]

68. Pursuant to section 8 of the MFA,[47] Nipigon LNG has been granted the necessary certificate of public convenience and necessity required to construct the LNG Facilities and connect to the TC Energy Mainline.[48]

69. Further, in respect of the construction and operation of facilities under the scope and responsibility of Nipigon LNG, and associated risks, Nipigon LNG submits the following:

    a. The LNG Facilities will use proven, low-complexity technologies for gas pre-treatment and liquefaction. Pre-treatment will be accomplished using a mole-sieve Temperature Swing Adsorption ("**TSA**") system. Liquefaction will be done by a double nitrogen expansion process. Both of these systems represent the most commonly used processes for LNG production in the small scale. An important factor in the selection of these systems was design and operational simplicity, and both systems are the least complex options available. The providers of these systems that are being considered by Nipigon LNG are the leaders in the marketplace and have abundant experience. Nipigon LNG considered the technology risk associated with the LNG production process and determined that based on the large number of similar plants operating reliably throughout North America, the risk was insignificant.[49]

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[44] OF-Tolls-Group1-T211-2018-01 01, National Energy Board Letter Decision, December 4, 2018. **[TAB 6]**
[45] Responses to OEB Staff Interrogatories, at Interrogatory 29(b).
[46] EB-2018-0248, Decision and Order, issued November 18, 2018. **[TAB 7]**
[47] RSO 1990, c. M.55.
[48] EB-2018-0248, Decision and Order, at page 5. **[TAB 7]**
[49] Responses to Certarus Interrogatories, at Interrogatory 8(g)

b. The Corporation considered the risks associated with construction and operation of the LNG Facilities. The risks of construction are limited to factors that would cause delays in the commencement of service from the LNG Facilities near Nipigon in the unincorporated Township of Ledger. These risks are real and are mitigated through the entire project development process being conducted by Nipigon LNG. Ultimately, delays in the commencement of service can be mitigated by procuring gas supplies from an alternate source. Practical options for replacement LNG supply exist in Canada and the northern United States.[50]

70. When the above factors are considered, it is clear that the Application demonstrates sufficient measures taken to assess and mitigate risk relating to the Project. These steps include a detailed review of all elements related to Nipigon LNG as the counter-party to the LNG Services Agreement, and completing the necessary review and implementing precautions to ensure the ability of Nipigon LNG to meet the requirements and obligations under the proposed agreement.

(c) Construction and Risk Mitigation

71. The LNG Services Agreement contains conditions precedent in section 3.1, which provide the Applicant with the assurance that it is not bound to a project that may not become operational or is constructed on materially different terms than initially contemplated.

72. The Applicant has accurately stated that Nipigon LNG assumes all construction risks related to potential capital cost overruns and project delays related to the LNG Services Agreement. In the event that Nipigon LNG fails to meet any condition precedent within a timeframe to be specified after the Applicant receives conditional approval of the Application, then the Applicant may terminate the LNG Services Agreement and seek alternative gas supply options.[51]

73. Additional considerations addressing the major risks associated with the LNG Services Agreement have been sufficiently mitigated by the Applicant for the following reasons:

   a. LNG is widely used by LDCs across North America as an alternative to pipelines and has a proven track record of cost-effectiveness, reliability, and safety;

   b. The Applicant has specified that a prudent and reasonable amount of LNG be stored on-system in each Municipality, in addition to the upstream LNG storage at the LNG Facilities; and

[50] *Ibid*.
[51] Responses to OEB Staff Interrogatories, at Interrogatory 29; Marathon Argument, at paragraph 75.

c. The Applicant has the flexibility to access alternative gas supplies, whether LNG or CNG, which are interchangeable with gas supplies delivered under the LNG Services Agreement.

74. Further, the LNG Services Agreement contains conditions precedent and other contractual terms that protect both the ratepayers and the Applicant's shareholders against construction and project execution risk.

V. SUBMISSIONS IN RESPECT OF INTERVENORS

75. The Board granted Nipigon LNG intervenor status in these proceedings for the purposes of providing submissions on the Gas Supply Plan and the LNG Services Agreement.

76. The submissions above have shown that the Applicant has duly assessed alternative gas supply sources that led to the selection of LNG as the preferred supply source, and performed a significant amount of due diligence regarding the proposed Gas Supply Plan and LNG Services Agreement.

77. On March 13, 2019, the Board issued directions in respect of the Application process, stating that the Board did not expect to undertake a competitive process with respect to the provision of natural gas services to the Municipalities. [52] This direction was based on the December 20, 2018, communication where the Board issued a letter requesting that any other party that is currently developing a plan to provide natural gas services to the Municipalities file a letter including certain enumerated minimum information by January 16, 2019. Among the required minimum information was confirmation that the party is in a position to file a complete application with the OEB by June 28, 2019.[53] No parties provided the required information, and in fact, Enbridge Gas Inc. filed notice that it would not compete to serve the municipalities.[54]

78. Where an intervenor attempts to make submissions in respect of a competitive bid or proposes an alternative to the relief sought by the Application, it is important that the Board take into account the commercial interests of the intervenor and whether the intervenor complied with the above requirements, namely, filing the minimum required information outlined above with the Board by January 16, 2019.

79. Nipigon LNG submits that to the extent the other intervenors in this proceeding make submissions, the OEB ought to consider such submissions in light of the commercial interests of the intervenors, whether such intervenors have entirely avoided or "jumped over" the planning and assessment stage of the Project, and whether such intervenors are attempting to re-litigate previously settled steps in these proceedings.

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[52] EB-2018-0329, OEB Letter Direction Dated March 13, 2019.
[53] *Ibid.*
[54] EB-2018-0329, Enbridge Gas Inc. Letter, Filed February 4, 2019.

80. Significant work has been conducted by the Corporation and Municipalities on behalf of their communities and stakeholders. The Application represents a complete package capable of satisfying the necessary requirements for approval by the Board. At this stage in the process, if the submissions of any intervenor impairs the relief sought by the Applicant, there will be significant prejudice to the Applicant and the stakeholders in the communities represented by the Applicant.

81. Nipigon LNG has, and continues, to engage in constructive discussions with First Nation and Métis communities regarding the LNG Facilities and the supply of gas to the Municipalities and potentially First Nation communities where feasible. These discussions have included frequent face-to-face meetings with representatives of Red Rock Indian Band ("**RRIB**") and the Bingwi Neyaashi Anishinaabek ("**BNA**") First Nation. Both RRIB and BNA have provided letters of support for the Application, which specifies gas supplied by Nipigon LNG under the LNG Services Agreement. In addition, RRIB and BNA have intervened in this proceeding on their own behalf to ensure the interests of their communities, including the economic opportunities and other benefits associated with the Project and the LNG Facilities, are taken into account by the Board.

(a) Certarus

82. The intervenor request submitted by Certarus on September 26, 2019 (the "**Certarus Request**") asserts that Certarus is able to provide competitive CNG supply to the Municipalities.[55] Certarus raised CNG as an alternative primary fuel to the LNG Services Agreement in its request to the OEB.[56] Certarus announced it was building a CNG facility in Red Rock after the Applicant had entered discussions for capacity with Nipigon LNG. Based on publicly available information issued by Certarus in May 2019, the CNG facility in Red Rock is intended to supply natural gas directly to industrial and commercial end-users in the mining, forestry, and industrial sectors currently running on diesel, bunker oil, or propane and makes no reference to communities whatsoever.[57]

83. The submissions and evidence of the Applicant make it clear that the Applicant considered Certarus as a possible natural gas provider during the initial assessment stage of the Project.

84. Specifically, the Corporation consulted representatives of Certarus in November 2017.[58] At these discussions, Certarus advised the Corporation that it did not contemplate supplying residential consumers or communities.[59]

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[55] Certarus Intervention Request at para 5.
[56] Certarus Intervention Request.
[57] Certarus Ltd. Press Release, May 23, 2019. **[TAB 8]**
[58] Responses to Certarus Interrogatories, at page 2.
[59] *Ibid*., at pages 2-3.

85. The Corporation deemed that Certarus' response constituted a failure to satisfy a critical project prerequisite. Further, the Corporation notes that at no point has Certarus provided any concrete information, data, or proposals that the Corporation may assess or rely on.[60]

86. At this stage of the Project, now over four years in development, it is improper for Certarus to attempt to competitively bid or intervene in the Application. Specifically, Certarus:

    a. Failed to submit a plan by January 16, 2019, as required by the Board's direction in these proceedings; and

    b. Is now attempting to add an adversarial and competitive consideration to the Application, despite the Board providing the Applicant certainty that review or consideration of new parties seeking to compete with the Project would not be considered.

87. The Applicant finalized and filed the Application in accordance with the direction of the Board, not contemplating that new parties would later be able to challenge or attempt to prevent the adoption of the Gas Supply Plan and the LNG Services Agreement based on a competitive offering.

88. Certarus has not complied with the procedural requirements in these proceedings, and accordingly, to the extent that its submissions or requested relief impair or adversely impact the Applicant and the Project, such submissions or requested relief should be disregarded.

89. Certarus' written interrogatories submitted to the Corporation contain a series of implied assertions or allegations regarding the risks associated with the proposed LNG Services Agreement and services to be provided by Nipigon LNG. As discussed above, risk mitigation has been thoroughly considered and addressed by the Applicant. Further points regarding risk mitigation provided by the Corporation in direct response to the interrogatories of Certarus include:

    a. Backup supply of LNG through the design of the LNG Depots, and the significant ability of truck-based transportation to provide flexibility in response to *force majeure* conditions or issues that arise;[61] and

    b. The LNG Services Agreement contains no provisions that preclude the Utility from contracting for other sources of natural gas supply.[62]

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[60] *Ibid*., at page 3.
[61] Responses to Certarus Interrogatories, at Interrogatory 5(c); See also Responses to OEB Staff Interrogatories, at Interrogatory 31.
[62] Responses to Certarus Interrogatories, at Interrogatory 13(a).

90. It is notable that the beneficial and prudent risk mitigation detailed above also explicitly addresses the shortfalls and risks associated with CNG-based supply.

91. For all of these reasons, Nipigon LNG submits that the submissions of Certarus ought to be disregarded to the extent that they deviate from or go beyond the discrete procedural directions of the Board.

92. Furthermore, Nipigon LNG submits that no terms contained in the Gas Supply Plan or the LNG Services Agreement would preclude the Applicant from procuring short-term and long-term supplies of CNG from Certarus or any other fuel supplier for any purpose at any time.

93. To the extent that the Applicant anticipates that additional gas supply agreements are required, the Applicant must only identify and substantiate the need for the proposed agreements in an annual update to the Gas Supply Plan, as is required by the Board.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 6th DAY OF JANUARY 2020.

Borden Ladner Gervais LLP

Per:

*Original signed by*______________
Alan L. Ross

*Original signed by*______________
Curtis Fawcett

TAB 1 - Filing Guidelines for Pre-Approval of Long-term Natural Gas Supply and/or Upstream Transportation Contracts dated April 23, 2009

Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

BY E-MAIL AND WEB POSTING

April 23, 2009

To: All Participants in EB-2008-0280

Re: Filing Guidelines for the Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts
Board File No.: EB-2008-0280

The purpose of this letter is to notify participants of the release of the final filing guidelines for the pre-approval of the cost consequences of long-term natural gas supply and/or upstream transportation contracts ("LTC filing guidelines"), which have been posted on the Board's website at www.oeb.gov.on.ca.

Background

In the Natural Gas Forum ("NGF") report, the Board concluded that it will:

- offer natural gas utilities the opportunity to apply for pre-approval of long-term natural gas supply and/or upstream transportation contracts; and
- consult on the development of guidelines that will inform all stakeholders of the principles and issues the Board will consider when evaluating an application for contract pre-approval.

In a letter, dated August 22, 2008, the Board outlined the issues to be addressed when developing a pre-approval process for long-term natural gas supply and/or upstream transportation contracts. The Board indicated that it would hold a consultation to discuss the needs, benefits and risks of entering into long-term contracts, the impact on competition and the filing guidelines.

Also, in its letter dated August 22, 2008, the Board stated that it planned to conduct the consultation in two phases. In the first phase, staff would hold stakeholder meetings which would lead to the development of a staff discussion paper. In the second phase, the Board would consider whether it is appropriate to develop filing guidelines for the pre-approval of long-term contracts.

On October 15-17, 2008, staff held a number of meetings with stakeholders. At these meetings, staff and its technical expert presented material to initiate discussion on whether: (i) it is appropriate for natural gas utilities to enter into long-term natural gas supply and/or upstream transportation contracts; and (ii) the Board should develop guidelines for the pre-approval of long-term contracts, and if so, what should be included in these guidelines.

At these meetings, no substantive issues were raised and stakeholders generally agreed to a pre-approval process for long-term contracts that support the development of new natural gas infrastructure (e.g., new pipeline facilities to access new natural gas supply sources such as Liquefied Natural Gas plants and frontier production). As a result, a staff discussion paper, as originally contemplated in Phase I of the consultation, was not necessary. The Board decided to proceed directly to Phase II and release its draft LTC filing guidelines for stakeholder comment. On February 11, 2009, the Board issued the draft LTC filing guidelines for stakeholder comment and the Report of the Board entitled Draft Filing Guidelines for the Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts ("the Report").

Ten stakeholders submitted comments on the draft LTC filing guidelines. The majority of these stakeholders supported the draft LTC filing guidelines and commented on the following matters:

- the actual contract itself should be filed as part of this process;
- this process should also include renewals of long-term contracts;
- this process should include any long-term contracts that involve an affiliate of the natural gas utility; and
- the Board should define what is meant by long-term.

One stakeholder, however, submitted that there is no need to determine at this time whether long-term contracts are appropriate since there are no current issues with security of supply or upstream transportation constraints. Therefore, it would be best for the Board to make a determination in the future if and when these concerns arise.

All materials related to these consultations (including stakeholders' comments) are available on the Board's website.

Final Filing Guidelines

The Board has decided to proceed with the finalization of the filing guidelines for the pre-approval of the cost consequences of long-term natural gas supply and/or upstream transportation contracts.

The filing guidelines in Attachment A reflect the comments by stakeholders, as appropriate. In response to the comments raised, the Board reiterates its policy as set out in the Report.

The Board believes that applications for pre-approval of the cost consequences of long-term contracts should be limited to those that support the development of <u>new</u> natural gas infrastructure. The Board does not believe that the pre-approval process should be used for the natural gas utility's ("utility") normal day-to-day contracting, renewals of existing contracts and other long-term contracts that are not related to new natural gas infrastructure. These contracts should continue to be addressed in the utility's rate proceedings.

Further, the Board is of the view that this pre-approval process should be an option available to the utility and not a requirement (even if the long-term contract involves an affiliate). As a consequence, the Board offers utilities the opportunity to apply on a case-by-case basis for pre-approval of these long-term contracts that support new natural gas infrastructure.

In its Report, the Board stated that it would pre-approve the costs associated with these contracts, not the contract itself. However, based on stakeholder comments, the Board believes that the contract should be filed as part of this process to allow for an appropriate review. The Board notes that the utility may request confidential treatment of its contract in accordance with the Ontario Energy Board's *Practice Direction on Confidential Filings*.

For additional clarity, the Board is of the view that defining long-term is not necessary since the pre-approval process is limited to projects that would support the development of new natural gas infrastructure. It is expected that the length of the contract will vary with, amongst other things, the nature and magnitude of the new natural gas infrastructure.

For any questions regarding the final LTC filing guidelines please contact Laurie Klein at laurie.klein@oeb.gov.on.ca or (416) 440-7661. The Board's toll free number is 1-888-632-6273.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

Attachment A

Attachment A

Filing Guidelines for Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts

This form applies to all applicants who are requesting pre-approval of the cost consequences of long-term natural gas supply and/or upstream transportation contracts that support the development of new natural gas infrastructure.

"Long-term" has not been defined since this pre-approval process is limited to projects that would support the development of new natural gas infrastructure. It is expected that the length of the contract will vary with, amongst other things, the nature and magnitude of the new natural gas infrastructure.

All applicants must complete and file the information requested in Part I, II, III, IV, V and VI.

Part I – Identification of Applicant

Name of Applicant:	File No: (OEB Use Only)
Address of Head Office:	Telephone Number:
	Facsimile Number:
	E-mail Address:
Name of Individual to Contact:	Telephone Number:
	Facsimile Number:
	E-mail Address:

Part II – Needs, Costs and Benefits

2.1	A description of the proposed project that includes need, costs, benefits (such as this project improves the security of supply and the diversity of supply sources) and timelines.
2.2	An assessment of the landed costs (supply costs + transportation costs including fuel costs) for the newly contracted capacity and/or natural gas supply compared to the landed costs of the possible alternatives.

Part III – Contract Diversity

3.1	A description of all the relevant contract parameters such as transportation/supply provider, contract length, conditions of service, price, volume, and receipt and delivery points.
3.2	An assessment on how the contract fits into the applicant's overall transportation and natural gas supply portfolio in terms of contract length, volume and services.

Part IV - Risk Assessment

4.1	Identification of all the risks (such as forecasting risks, construction and operational risks, commercial risks and regulatory risks) and plans on how these risks are to be minimized and allocated between ratepayers, parties to the contract and/or the applicant's shareholders. For example, forecasting risks include future demand, prices, actual landed costs and performance of basin; commercial risks include competitive and credit-worthiness of provider/operator; construction and operational risks include costs escalations, delays or reliability issues pertaining to new construction, and gas interchangeability and quality issues; and regulatory risks include changes in laws or regulations.

Part V – Other Considerations

5.1	A description of the relationship and any other conditions, rights or obligations between the parties to the contract and the applicant's parent company and/or affiliates.
5.2	An assessment of retail competition impacts and potential impacts on existing transportation pipeline facilities in the market (in terms of Ontario customers).

Part VI – Contract

6.1	The contract for which the utility is seeking pre-approval for is filed in this application. The utility may request confidential treatment of its contract in accordance with the Ontario Energy Board's *Practice Direction on Confidential Filings.*

TAB 2 – OEB Decision and Order dated December 17, 2015, EB-2015-0166 / EB-2015-0175

Ontario

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2015-0166 / EB-2015-0175

UNION GAS LIMITED

ENBRIDGE GAS DISTRIBUTION INC.

Applications for Pre-Approval of the Cost Consequences of Long-Term Natural Gas Transportation Contracts for Capacity on the NEXUS Pipeline

BEFORE: Cathy Spoel
Presiding Member

Christine Long
Member

Allison Duff
Member

December 17, 2015

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY

Union Gas Limited (Union) and Enbridge Gas Distribution Inc. (Enbridge) are the two largest natural gas distribution companies in Ontario. Union serves about 1.4 million residential, commercial and industrial customers in communities across northern, southwestern and eastern Ontario. Enbridge serves over 2 million residential, commercial and industrial customers in communities across central and eastern Ontario.

Union and Enbridge each signed a precedent agreement with the developers of the NEXUS pipeline (NEXUS). Union and Enbridge intend to use the NEXUS pipeline to transport gas from the Appalachian region of the United States to the Dawn hub in southwestern Ontario.

Union and Enbridge each applied to the Ontario Energy Board (OEB) for pre-approval of the cost-consequences of 15-year transportation contracts (collectively referred to as the Contracts, or individually as the Contract) under section 36 of the *Ontario Energy Board Act, 1998* and the OEB's Filing Guidelines for Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts (the Guidelines).[1] The OEB heard the two applications together.

The proposed NEXUS pipeline consists of 400 kilometres of new pipeline that would run from Kensington in eastern Ohio to Willow Run in southeastern Michigan. The NEXUS pipeline is being developed jointly by Spectra Energy Transmission, LLC (Spectra) and the DTE Pipeline Company (DTE).[2]

Union and Enbridge would both flow gas supplies on the new portion of the NEXUS path from Kensington to Willow Run, as shown on the map below, which was provided by Union and Enbridge.[3] From there, Union's supplies would flow on the existing DTE system to the St. Clair pipeline and on the St. Clair pipeline to the Dawn hub. In the

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[1] EB-2008-0280, Filing Guidelines for Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts, April 23, 2009. In this Decision and Order, we use the term "Guidelines" to refer to the entire April 23, 2009 document, i.e. both the cover letter and the actual form to be completed by the applicant for pre-approval.

[2] Spectra and DTE are the counterparties to Union and Enbridge on the precedent agreements each utility has signed for NEXUS capacity. The recent application for US Federal Energy Regulatory Commission approvals was submitted by NEXUS Gas Transmission, LLC, which the application states is a 50-50 joint venture owned by affiliates of Spectra Energy Partners, LP and DTE Energy Company: "Abbreviated Application for Certificates of Public Convenience and Necessity and Related Authorizations," November 20, 2015, at p. 5.

[3] EB-2015-0166 / EB-2015-0175, Exhibit K1.1 at p. 4.

case of Enbridge, gas supplies would flow on the existing DTE system to the Vector pipeline (at the Milford Junction) and on the Vector pipeline to Dawn.

Under the precedent agreements, Union and Enbridge each committed to a 15-year transportation contract, provided that certain conditions precedent are met. One of the conditions precedent is that the utilities obtain pre-approval of the cost consequences of the Contracts.

Union's precedent agreement is for 150,000 Dth/day of capacity on NEXUS for a 15-year period.[4] The annual cost of the Contract is about US$48 million, which results in a total cost over the term of the Contract of about US$715 million.[5] By contracting for

[4] EB-2015-0166 / EB-2015-0175, Union Pre-Filed Evidence, Exhibit A at p. 43.

[5] EB-2015-0166 / EB-2015-0175, Union Argument-in-Chief, November 18, 2015 at p. 6. Union's cost estimate is based on the upper end of the NEXUS toll, which reflects potential capital cost overruns related to the greenfield portion of the pipeline. The actual cost for the transportation capacity on NEXUS could be less depending on the actual costs to build the NEXUS pipeline.

150,000 Dth/day, Union received anchor shipper status, which results in a discount on the toll.[6]

Enbridge's precedent agreement is for 110,000 Dth/day of capacity on NEXUS for a 15-year period.[7] The annual cost of the Contract is about US$28 million, which results in a total cost over the term of the Contract of about US$420 million.[8] Enbridge does not have anchor shipper status. Although Enbridge's precedent agreement includes an option to increase its capacity from 110,000 Dth/day to 150,000 Dth/day, Enbridge has requested pre-approval of only the costs associated with the 110,000 Dth/day.[9]

For the reasons that follow, the OEB approves the applications for pre-approval of the cost consequences of the Contracts. The OEB finds that the NEXUS pipeline meets the eligibility criteria for pre-approval as it is new infrastructure. The OEB also finds that the Contracts result in increased gas supply diversity by securing direct transportation from the source in the Appalachian Basin. The OEB finds that Union and Enbridge have made prudent decisions on behalf of system supply customers who rely on these utilities to contract for their gas supply needs.

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[6] *Ibid.* at p. 4.
[7] EB-2015-0166 / EB-2015-0175. Enbridge Pre-Filed Evidence, Exhibit A / Tab 3 / Schedule 1 at p. 17.
[8] *Ibid.* at p. 19. Enbridge's cost estimate reflects the base case for the NEXUS toll, which does not reflect any capital cost overruns related to the greenfield portion of the pipeline. The actual cost for the transportation capacity on NEXUS could be higher or lower, depending on the actual costs to build the NEXUS pipeline.
[9] EB-2015-0166 / EB-2015-0175, Oral Hearing Transcripts, Volume 2, November 16, 2015 at p. 104.

2 THE PROCESS

Union filed its application for pre-approval of the cost consequences of its Contract on May 28, 2015.[10] Enbridge filed its application on June 5, 2015.[11]

A Notice of Hearing for Union's application was issued on June 26, 2015 and a Notice of Hearing for Enbridge's application was issued on July 2, 2015.

In Procedural Order No. 1, dated July 31, 2015, the OEB combined the two proceedings. The OEB also granted intervenor status to a number of parties. A list of intervenors is set out below:

- Association of Power Producers of Ontario (APPrO)
- Building Owners and Managers Association, Greater Toronto (BOMA)
- Canadian Manufacturers and Exporters (CME)
- Consumers Council of Canada (CCC)
- Energy Probe Research Foundation (Energy Probe)
- Federation of Rental-housing Providers of Ontario (FRPO)
- Industrial Gas Users Association (IGUA)
- Just Energy Ontario L.P. (Just Energy)
- Kitchener Utilities (Kitchener)
- London Property Management Association (LPMA)
- School Energy Coalition (SEC)
- Mr. Ron Tolmie
- TransCanada Energy Ltd. (TCE)
- TransCanada PipeLines Limited (TransCanada)
- Vulnerable Energy Consumers Coalition (VECC)

Before the hearing started, an issue arose concerning the scope of the evidence to be admitted. One of the intervenors, Ron Tolmie, notified the OEB that he intended to file evidence on exergy storage and other related issues. In Procedural Order No. 2, the OEB decided that it would not accept his proposed evidence as it was outside the scope of the proceeding.

In response to a challenge filed by Mr. Tolmie, a differently constituted panel of the OEB heard a motion to review Procedural Order No. 2. The OEB dismissed Mr. Tolmie's

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[10] EB-2015-0166.
[11] EB-2015-0175.

motion and upheld the decision in Procedural Order No. 2 to exclude his proposed evidence.[12]

An oral hearing on the applications for pre-approval was held on November 13, 16 and 17, and December 2, 2015.

The OEB received written submissions from the applicants, OEB staff and the intervenors, and heard oral reply argument from the applicants on December 2, 2015.

Union and Enbridge requested that the OEB issue a decision by December 21, 2015 in order to allow them to meet the terms of their precedent agreements.

[12] EB-2015-0277, Decision and Order on Motion, October 30, 2015.

3 STRUCTURE OF THE DECISION

Chapter 4 sets out the OEB's findings regarding how long-term transportation contracts are to be evaluated under the Guidelines. Chapter 5 then applies that evaluation framework to the proposed NEXUS contracts. Chapter 6 addresses cost awards.

4 THE ISSUES – THE TEST FOR PRE-APPROVAL

The Guidelines[13] establish a two-part test for obtaining pre-approval. The first part of the test determines whether the type of contract is eligible for pre-approval. If the contract is eligible, the second part of the test determines whether pre-approval should be granted. The Guidelines do not provide specific criteria for the second part of the test, yet indicate the evidence to be filed in support of the application, including the needs, costs, benefits, diversity and risks associated with the contract. The OEB's assessment of both parts of the test determines whether pre-approval is granted.

OEB approval is not required for the utilities to proceed with the Contracts. The utilities may proceed without pre-approval. However, without pre-approval, the utilities' shareholders will bear the risk of recovering the cost consequences of the Contracts in the future.

OEB pre-approval guarantees that Union and Enbridge will be allowed to collect from their customers the NEXUS costs over the 15-year term of the Contracts (approximately US$715 million in Union's case and US$420 million in Enbridge's case). With pre-approval, an OEB decision is issued before the Contracts take effect. In this way, OEB decisions are not deferred to the future and the utilities have certainty with respect to long-term contracting.

4.1 Part 1 of the Test: Are the Contracts Eligible for Pre-Approval?

Parties had different views on what types of contracts are eligible under the Guidelines. OEB staff and several intervenors argued that only contracts that would bring new sources of gas supply to the Ontario market should qualify. Union and Enbridge maintained that the source of gas supply was not crucial to the pre-approval analysis, provided that the contracts support new infrastructure.

Pre-approval of the cost consequences of a utility's gas transportation or commodity contracts is a departure from the OEB's normal approach. Usually such costs are reviewed through the regular rate-setting process.

The Guidelines arose from the recognition that utilities might not be willing to enter the long-term commitments that are sometimes demanded by the developers of new pipelines or other gas infrastructure unless they were assured in advance that the OEB would not disallow the costs associated with such commitments. Without pre-approval,

[13] *Supra,* footnote 1.

needed infrastructure might not be built. As the OEB explained in its January 27, 2011 decision in EB-2010-0300 / EB-2010-0333, a case where it had to determine an application under the Guidelines, the adoption of the pre-approval process "was recognition by the Board that as a matter of commercial reality the developers of natural gas infrastructure must in some circumstances require long-term commitments to support large infrastructure investments."[14] To facilitate the development of such infrastructure, "it was reasonable to make provision for an extraordinary process wherein the costs consequences of such long term arrangements could be pre-approved".[15]

In the OEB's 2005 report on the Natural Gas Forum (a broad OEB-led regulatory review of the gas sector), the OEB accepted that pre-approval may be appropriate for some long-term contracts, and undertook to consult on the development of pre-approval guidelines:

> The Board believes that there is a role for utilities in long-term upstream transportation contracting, but the Board is not in favour of new long-term utility supply contracts at this time. However, the Board will offer utilities the opportunity to apply for pre-approval of long-term supply and/or transportation contracts. Further, the Board will consult on the development of guidelines that will inform all stakeholders of the principles and issues the Board will consider when evaluating an application for contract pre-approval.[16]

In 2008, the OEB initiated stakeholder consultations on the development of a pre-approval process for long-term gas supply and transportation contracts. This consultation resulted in the OEB-issued "Draft Filing Guidelines for the Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts" (the Draft Guidelines).[17] The OEB indicated that during the consultative process, "no substantive issues were raised and stakeholders generally agreed to a pre-approval process for long-term contracts that support the development of new natural gas infrastructure (e.g., new pipeline facilities to access new natural gas supply sources such as Liquefied Natural Gas plants and frontier production)."[18] The OEB also issued a report attached to the Draft Guidelines which indicated:

[14] EB-2010-0300 / EB-2010-0333, Decision and Order, January 27, 2011 at p. 7.
[15] *Ibid.* at p. 7.
[16] Ontario Energy Board, Natural Gas Regulation in Ontario: A Renewed Policy Framework, March 30, 2005 at pp. 5-6.
[17] EB-2008-0280, Draft Filing Guidelines for the Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts, February 11, 2009.
[18] *Ibid.* at p. 2.

> The Board believes that these applications should be limited to those that support the development of new natural gas infrastructure (e.g., new transportation facilities to access new natural gas supply sources). The Board does not believe that the pre-approval process for long-term contracts should be used for the utility's normal day-to-day contracting, renewals of existing contracts and other long-term contracts. These contracts should continue to be addressed in the utility's rate application.[19]

After considering stakeholder comments on the Draft Guidelines, the OEB issued the final Guidelines on April 23, 2009.

Findings

The OEB finds the Guidelines apply to new pipeline infrastructure and are not limited to new pipeline infrastructure from a new gas supply source. The Guidelines state:

> This form applies to all applicants who are requesting pre-approval of long-term natural gas supply and/or upstream transportation contracts that support the development of new natural gas infrastructure.[20]

Although the Guidelines indicate that the source of gas may be a relevant factor, the source of gas is not the determinative factor. Under the heading "Needs, Costs and Benefits", the Guidelines require an applicant to describe the proposed project including the "benefits (such as this project improves the security of supply and the diversity of supply sources)".[21] The OEB finds the meaning of the words "such as" to be clear. The words merely precede an illustrative example of a benefit that might weigh in favour of pre-approval. They do not expand upon the pre-requisite for pre-approval.

The OEB elaborated on the eligibility requirements for pre-approval in the final Guidelines:

> The Board believes that applications for pre-approval of the cost consequences of long-term contracts should be limited to those that support the development of <u>new</u> natural gas infrastructure. The Board does not believe that the pre-approval process should be used for the natural gas utility's ("utility") normal day-to-day contracting, renewals of existing contracts and other long-term contracts that are not related to new natural gas infrastructure. These contracts should continue to be addressed in the utility's rate proceedings.[22]

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[19] EB-2008-0280, Report of the Board: Draft Filing Guidelines for the Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts (Attachment B to the Draft Guidelines), at p. 4.
[20] Guidelines at p. 4.
[21] *Ibid.* at p. 4 (part 2.1).
[22] *Ibid.* at p. 2 (emphasis in original).

In the final Guidelines, the OEB repeated its observation that “stakeholders generally agreed to a pre-approval process for long-term contracts that support the development of new natural gas infrastructure (e.g., new pipeline facilities to access new natural gas supply sources such as Liquefied Natural Gas plants and frontier production.)”[23] While some parties argued that this means the Guidelines only apply to new infrastructure if it is used to access these new sources of supply, the OEB finds this interpretation too narrow. These are given as examples and cannot be interpreted as restricting the pre-approval process only to pipelines that access new natural gas supply sources. This is an illustrative, rather than an exhaustive, list of the types of projects that may be eligible for cost pre-approval. The OEB finds that the key factor is whether the infrastructure is new, not whether the source of gas supply is new.

The OEB acknowledges that the panel in EB-2010-0300 / EB-2010-0333 went further than this, remarking that “the purpose of the pre-approval process is to support the development of new transportation facilities <u>to access new natural gas supply sources.</u>”[24] The panel in that case explained that “there must be a compelling case that without the reallocation of risk to the ratepayer from the shareholder arising from pre-approval, new natural gas transportation infrastructure would not be constructed and new natural gas supplies would remain beyond the reach of the market.”[25]

The source of supply was not the decisive factor in EB-2010-0300 / EB-2010-0333. The panel had already determined that the contracts were ineligible for pre-approval because they did not support the development of new gas infrastructure.[26] To the extent the decision suggests that pre-approval is only available for contracts for new sources of gas, this panel finds it unpersuasive. Nor do these comments build upon or change the original objectives of the Guidelines. The Guidelines remain the source document for the OEB and this Decision. The OEB finds that one objective of the Guidelines is to facilitate the construction of new gas infrastructure.

In summary, the OEB finds that a long-term gas supply or transportation contract will be eligible for pre-approval if it supports the development of new natural gas infrastructure. Although “long-term” is not defined in the Guidelines, it was not disputed in this proceeding that the 15-year term of the proposed NEXUS Contracts would qualify. There is no precondition that the contract relate to gas from a new source of supply. However, the proposed contract’s effect on supply diversity is a relevant factor to

[23] *Ibid.* at p. 2.
[24] EB-2010-0300 / EB-2015-0333, Decision and Order, January 27, 2011 at pp. 9-10 (emphasis added).
[25] *Ibid.* at p. 10.
[26] *Ibid.* at p. 9.

consider at the second stage of the test, that is, the evaluation of a contract on its merits.

4.2 Part 2 of the Test: Should the Cost Consequences of the Contracts be Pre-approved?

The Guidelines set out the information and analysis that must be included in an application for pre-approval of a long-term contract, and provide a framework for assessing whether the contract and its associated costs consequences are reasonable.

The Guidelines include the following key factors for OEB consideration:

1. Need, Costs and Benefits of the project
2. Contract Diversity
3. Risk Assessment
4. Other Considerations
    a. Affiliate Relationships
    b. Retail Competition Impacts

5 EVALUATING THE PROPOSED NEXUS CONTRACTS UNDER THE GUIDELINES

5.1 Are the Contracts Eligible for Pre-Approval?

OEB staff and several intervenors argued that the NEXUS Contracts are not eligible for pre-approval under the Guidelines because the Contracts are not needed to bring new sources of natural gas to the Ontario market. These parties argued that Union and Enbridge already receive supply from the Appalachian region via pathways other than NEXUS. Some also argued that, even without pre-approval of the NEXUS costs, NEXUS and/or other new transportation infrastructure, such as the proposed Rover pipeline, are likely to be built to deliver Appalachian gas to the Ontario market.

Other parties supported Union and Enbridge. These parties argued that the NEXUS Contracts are eligible for pre-approval as they support the development of new infrastructure that will bring economic gas supplies to Ontario for the benefit of Union's and Enbridge's ratepayers.

Findings

The OEB finds that the Contracts are eligible for pre-approval. The Contracts clearly support the development of new natural gas infrastructure, namely the 400 kilometres of brand new pipeline from Kensington to Willow Run.

Both Union and Enbridge indicated that without pre-approval the utilities would not proceed with the Contracts.[27] The utilities would not commit to 15-year contracts as the cost consequences would be subject to subsequent prudence reviews and approvals by the OEB. Although the utilities considered the Contracts prudent, the utilities were not willing to assume the risk that the costs would not be approved in the future. The utilities submitted that the cost of gas supply is a pass-through expense and the utilities are not compensated for taking any associated gas supply risks. The Guidelines were established to address this issue.

The utilities are entrusted to make prudent decisions on behalf of system gas users and participate in competitive markets to do so. Yet the utilities' compensation structure may inhibit or dissuade the commitment to otherwise prudent contracts. In this case, the OEB finds that consideration of pre-approval of the cost consequences is justified.

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[27] EB-2015-0166 / EB-2015-0175, Union Argument-in-Chief, November 18, 2015 at p. 2; and EB-2015-0166 / EB-2015-0175, Enbridge Argument-in-Chief, November 18, 2015 at p. 15.

Although the evidence was not conclusive, there is reason to doubt that the NEXUS pipeline would be built without the long-term transportation contracts, which include those of Union and Enbridge. Together, the Union and Enbridge Contract commitments account for almost one-third of the total contracted capacity on NEXUS.[28] As contracted capacity is only 55% of the physical capacity, if Union and Enbridge did not sign the Contracts, only 38% of physical capacity would be subscribed,[29] which would call the project's viability into question.

Some parties argued that some portion of the costs of the Contracts are not eligible for pre-approval because a portion of the Contracts rely upon existing infrastructure, in addition to new NEXUS infrastructure. The OEB disagrees. Under the Contracts, Union would pay one integrated toll for the entire pathway (both new build and existing pipeline) from Kensington to the St. Clair pipeline.[30] Similarly, Enbridge would pay one integrated toll for the entire pathway from Kensington to the Vector pipeline.[31] The threshold for eligibility is whether the Contracts support the development of new natural gas infrastructure. It is not whether the Contracts relate only to new infrastructure. The NEXUS Contracts are eligible as they will support the development of 400 kilometres of new pipeline.

5.2 Should the Cost Consequences of the Contracts be Pre-approved under the Guidelines?

Using the Guidelines as a template, the OEB will consider the following factors in its analysis of whether the proposed NEXUS contracts are reasonable:

1. Need, Costs and Benefits of the project
2. Contract Diversity
3. Risk Assessment
4. Other Considerations
    a. Affiliate Relationships
    b. Retail Competition Impacts

[28] EB-2015-0166 / EB-2015-0175, Union Reply Argument Summary, December 2, 2015 at p. 16.
[29] *Ibid.*
[30] EB-2015-0166 / EB-2015-0175, Union Pre-Filed Evidence, Exhibit A at p. 43.
[31] EB-2015-0166 / EB-2015-0175, Enbridge Pre-Filed Evidence, Exhibit A / Tab 3 / Schedule 1 at p. 17.

5.2.1 Need, Costs and Benefits of the Project

The Guidelines indicate applications for the pre-approval must include evidence regarding the need, costs and benefits of the proposed project and a landed cost analysis comparing the proposed project to alternatives.[32] The costs are known and defined in the Contracts. The benefits are not known and must be forecasted.

Union and Enbridge provided analysis which outlined the benefits of the Contracts, including: improvements to supply and transportation diversity, supply security, reliability, enhanced liquidity at Dawn, and the ability to access a competitively priced (Enbridge) or a less expensive (Union) source of supply. A number of parties agreed.

Other parties argued that the benefits cited by Union and Enbridge could be achieved without the NEXUS pipeline and without committing to long-term transportation contracts. The parties submitted that the same benefits could be achieved at a lower risk to ratepayers, by purchasing delivered supplies at Dawn or through Niagara, for example.

Findings

The OEB finds that substantial benefits will accrue to Union’s and Enbridge’s customers through the proposed long-term Contracts for transportation capacity on the NEXUS pipeline. To prove the need for the NEXUS project, it is not necessary to convince the OEB that there are no alternatives to the project. It is sufficient for the OEB to assess the benefits that will accrue to customers against the costs to customers. The Guidelines do not prescribe a specific test, yet some intervenors submitted that the benefits must be proven to exceed the costs.

The difficulty in comparing costs, which are defined, to benefits, which are forecast and assumed, is that the future is unknown. The quantification of benefits is subject to its own forecast risk as no one knows what the future holds with or without the NEXUS pipeline.

The OEB is of the view that establishing a direct transportation link between Ontario and the Appalachian basin is an important opportunity for Ontario’s natural gas market. It is the key, differentiating benefit of the Contracts, compared to the alternatives proposed. As noted by Sussex Economic Advisors, an expert retained jointly by Union and

[32] Guidelines at p. 4 (Part II).

Enbridge, the Appalachian basin is the fastest growing natural gas supply basin in North America.[33]

The OEB agrees with Union and Enbridge that procuring supply directly in the Appalachian region results in benefits that could not be achieved through the purchase of delivered natural gas supplies at a market hub. These benefits include access to pricing signals, and pricing indices available in the Appalachian region that the utilities would not be able to access directly without the Contracts. The OEB finds that this new, direct access enhances diversity of supply. In situations where gas prices are increasing at one location, the ability to access gas supply at another location provides alternatives that can reduce price volatility. In addition, the evidence indicates that at times of peak demand, a lack of transportation capacity can be the primary constraint driving cost increases for the utilities.[34]

For Union, the Appalachian supplies flowing on NEXUS will replace some of its Western Canadian supplies.[35] The increase in diversity is most pronounced in Union's northern service area, which is currently 100% reliant on Western Canadian gas,[36] although diversity will also be improved in Union's southern service area. In the case of Enbridge, the Appalachian supplies flowing on NEXUS will replace some of the gas currently sourced at Chicago,[37] which will enhance the diversity of Enbridge's supply portfolio. The OEB finds that transportation diversity will be enhanced for both Union and Enbridge by the addition of a new, direct route for Appalachian basin gas to reach Dawn.

Union and Enbridge each conducted a landed cost analysis comparing the Contracts to various alternatives. The utilities used different methodologies and assumptions, which resulted in different outcomes. For instance, Union's analysis indicated that the Contracts would be cheaper than buying gas at Dawn, whereas Enbridge's analysis indicated that the Contracts would be about 10% more expensive than the Dawn option.[38] The OEB recognizes that there is always a level of uncertainty with long-term

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[33] Sussex Economic Advisors, Union Gas Limited and Enbridge Gas Distribution Inc., NEXUS Gas Transmission – Market Study, May 2015 at p. 21.
[34] EB-2015-0166 / EB-2015-0175, Oral Hearing Transcripts, Volume 2, November 15, 2015 at p. 128.
[35] EB-2015-0166 / EB-2015-0175, Union Pre-Filed Evidence, Exhibit A at pp. 10-11.
[36] *Ibid.* at p. 29.
[37] EB-2015-0166 / EB-2015-0175, Enbridge Pre-Filed Evidence, Exhibit A / Tab 3 / Schedule 1 at p. 28.
[38] EB-2015-0166 / EB-2015-0175, Union Interrogatory Responses, Exhibit B .T1.Union.TCPL.2 at Attachment 1; EB-2015-0166 / EB-2015-0175, Enbridge Interrogatory Responses, Exhibit I.T1.Enbridge.TCPL.3 at p. 2; EB-2015-0166 / EB-2015-0175, Oral Hearing Transcripts, Volume 2, November 16, 2015 at pp. 132-133.

price forecasts yet is satisfied that, taken together, the two landed cost analyses support the applicants' contention that the Contracts are cost-competitive.

Various alternatives to the NEXUS pipeline were discussed over the course of the proceeding. One alternative was the proposed Rover pipeline announced in June 2014. Rover follows a similar path as NEXUS and has a similar toll.[39] The announcement of the Rover pipeline was made after Union and Enbridge had entered discussions for capacity on NEXUS. Rover is supported by a number of natural gas suppliers that have subscribed for capacity to bring natural gas to Dawn[40] and an application related to the project is currently before the US Federal Energy Regulatory Commission.[41] If the Rover project is built, it would provide a direct connection between Ontario and the Appalachian region. At this time, however, it is not certain that Rover will proceed. Even if it is built, the evidence indicates that there is no available capacity for Union and Enbridge, as the project is already fully subscribed.[42] For these reasons, the prospect of Rover being built does not preclude the OEB from pre-approving the Contracts.

Another alternative to NEXUS raised was the transportation of Appalachian gas to Ontario through Niagara. Enbridge, beginning in 2016, will flow a significant quantity of gas (200,000 GJ/d) through Niagara.[43] The OEB finds that Enbridge's NEXUS contract provides an appropriate balance to its capacity through Niagara and sufficiently diversifies its natural gas supply portfolio in terms of supply sources and transportation paths. Union has a contract for about 21,000 GJ/d of capacity through Niagara.[44] Some intervenors suggested that Union should have participated in previous open seasons for additional capacity through Niagara. The OEB does not find flowing gas through Niagara to be a comparable alternative to the Contracts which provide direct access at the gas supply source through NEXUS. In addition, the OEB does not find Niagara to be a viable alternative as the evidence indicates that capacity at Niagara is not available in sufficient quantities to meet Union's needs.[45]

In summary, the OEB finds that the quantitative and qualitative benefits arising from the Contracts justify the cost consequences.

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[39] EB-2015-0166 / EB-2015-0175, Union Pre-Filed Evidence, Exhibit A at p. 24.
[40] EB-2015-0166 / EB-2015-0175, Oral Hearing Transcripts, Volume 1, November 13, 2015 at pp. 35-36.
[41] *Ibid.* at p. 26.
[42] *Ibid.* at p. 38.
[43] EB-2015-0166 / EB-2015-0175, Oral Hearing Transcripts, Volume 2, November 16, 2015 at pp. 131-132, 141.
[44] EB-2015-0166 / EB-2015-0175, Union Interrogatory Responses, Exhibit B.T3.Union.BOMA.33 at p. 1.
[45] EB-2015-0166 / EB-2015-0175, Exhibit K2.2 and Undertaking J2.2.

5.2.2 Contract Diversity

The Guidelines require applications for pre-approval to include an assessment of how the contract fits into the applicant's overall transportation and natural gas supply portfolio in terms of contract length, volume and services.[46]

Union's precedent agreement is for 150,000 Dth/day of capacity on NEXUS for a 15-year period. This represents approximately 33% of Union's overall natural gas supply portfolio.[47] Enbridge's precedent agreement is for 110,000 Dth/day of capacity on NEXUS for a 15-year period. This represents approximately 15% of Enbridge's annual system gas requirements.[48]

Union and Enbridge argued that the NEXUS Contracts fit well within their gas supply portfolios. A number of intervenors agreed.

Some parties argued that alternative supply arrangements – or, at least in Union's case, a reduction in the contracted capacity on NEXUS – would better fit the applicants' overall transportation and gas supply portfolio.

Findings

The OEB finds that securing transportation capacity on a new pipeline increases contract diversity. In addition to contract diversity for transportation, the OEB finds the Contracts will increase supply diversity. As a result, the proposed Contracts are appropriate additions to the applicants' gas supply portfolios. While the Contracts represent a significant portion of each applicant's overall gas supply portfolio, the OEB does not find that the Contracts represent an overreliance on a single contract.

5.2.3 Risk Assessment

The Guidelines require applications for pre-approval to include a description of all the risks associated with a project and the applicant's plans for minimizing the identified risks.[49]

Union and Enbridge identified risks and provided risk mitigation strategies as part of their respective applications.

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[46] Guidelines at p. 5 (Part III).
[47] EB-2015-0166 / EB-2015-0175, Union Argument-in-Chief, November 18, 2015 at p. 8.
[48] EB-2015-0166 / EB-2015-0175, Enbridge Argument-in-Chief, November 18, 2015 at p. 1.
[49] Guidelines at p. 5 (Part IV).

The applicants stated that there are construction and operational risks directly associated with the NEXUS project itself, largely in terms of potential changes to the capital costs and project delays. The applicants stated that they have mitigated these risks through the inclusion of a capital cost adjustment mechanism and other protections in their precedent agreements.

There are also forecasting risks associated with the Contracts. The applicants stated that they have adequate flexibility in the remainder of their supply and transportation portfolios to ensure that if there is a reduction in demand for gas relative to their forecasts they will not be left with unused excess capacity on the NEXUS pipelines.

The applicants also discussed risks, and risk mitigation strategies, associated with supply forecasting and regulatory changes.

A number of parties supported Union and Enbridge and submitted that the risks have been adequately addressed. In addition, these parties assert that the benefits of the long-term Contracts outweigh the costs, including the associated risks.

Some parties opposed pre-approval on the basis that it shifts risks that should properly be the responsibility of the applicants' shareholders to the customer. These parties argued that if the utilities believe that the Contracts are prudent they should sign the Contracts even in the absence of pre-approval. Other parties argued that there is uncertainty regarding pricing and demand in the natural gas market and committing to substantial transportation capacity for a 15-year period is not a reasonable course of action at this time.

Findings

There are two main types of risk associated with the proposed Contracts: (a) construction risks and (b) customer financial risks.

The construction risks are related to potential capital cost overruns and project delays or cancellation. The OEB finds that the construction risks have been adequately mitigated through the precedent agreements.

In particular, the precedent agreements include a capital cost tracker, which will cap the applicants' exposure to any cost overruns that may occur. The same mechanism enables the applicants to pay a lower toll if the project comes in under budget.[50] The

[50] EB-2015-0166 / EB-2015-0175, Union Pre-Filed Evidence, Exhibit A at pp. 46-47; and EB-2015-0166 / EB-2015-0175, Enbridge Pre-Filed Evidence, Exhibit A / Tab 3 / Schedule 1 at p. 40.

precedent agreements also allow the applicants to withdraw in the event of a major delay or cancellation, without penalty or liability.[51]

The customer financial risks relate to the changes that could occur in the natural gas market over the term of the Contracts. There could be a reduction in gas demand as compared to forecast, which would reduce the need for capacity on the NEXUS pipeline. Lower cost supply and transportation options could become available; these opportunities could be lost to system gas customers due to the Contracts held by the applicants for NEXUS capacity.

With respect to demand forecasting risks, the OEB finds that the applicants' gas supply portfolios include a significant component that is not committed, which can be used to address reductions in natural gas demand. In addition, the utilities could opt not to renew short-term contracts. The OEB finds, based on the evidence, that there is little risk that any portion of the costs associated with the Contracts will become stranded due to reductions in gas demand over the 15-year term, thereby creating financial risk to customers.

Similarly, even if lower priced gas supply and transportation options became available at some point in the 15-year term, the applicants will have enough flexibility in their overall gas supply portfolios to take advantage of those opportunities.

In summary, the OEB finds that the construction risks associated with the NEXUS have been sufficiently mitigated by the applicants through their precedent agreements. The OEB also finds that the flexibility that exists in the applicants' gas supply and transportation portfolios will mitigate the ratepayer financial risks. This flexibility would allow the applicants to access future opportunities for lower cost gas supplies (if they become available) and would protect ratepayers from potential stranded costs associated with any potential decline in the demand for gas.

Overall, the OEB is satisfied that the benefits of the proposed NEXUS Contracts, as discussed in section 5.2.1, outweigh the financial costs of the Contracts and the associated risks discussed above.

The OEB also notes that the applicants and some intervenors are correct to point out that, just as there are risks associated with pre-approving the cost consequences of the Contracts, there are risks associated with not approving them. The Guidelines do not reference opportunity costs within the Risk Assessment section. The opportunity cost is

[51] EB-2015-0166 / EB-2015-0175, Union Pre-Filed Evidence, Exhibit A at p. 47; and EB-2015-0166 / EB-2015-0175, Enbridge Pre-Filed Evidence, Exhibit A / Tab 3 / Schedule 1 at pp. 40-41.

the cost to replace the direct transportation link resulting from the Contracts. The Ontario market could be deprived of the opportunity to be directly connected to the Appalachian basin with the corresponding benefits previously described.

5.2.4 Other Considerations

The Guidelines require applications for pre-approval to include a description of the relationship between the parties to the contract and the applicant's parent company and/or affiliates. Applications must also include an assessment of the retail competition impacts and impacts on existing transportation pipeline facilities.[52]

Union acknowledged that its corporate parent, Spectra Energy Corporation, has an interest in the NEXUS project. Spectra Energy Corporation owns both Union and Spectra Energy Transmission, LLC, one of the co-developers of NEXUS.[53] One party expressed concern that Union's Contract therefore was non-compliant with the OEB's Affiliate Relationship Code (ARC). However, the evidence indicated that none of the Spectra entities has a controlling interest in the NEXUS project; rather, the project is a 50-50 joint venture with the DTE Energy Company.[54] As a result, Union and NEXUS Gas Transmission, LLC are not affiliates within the meaning of the ARC. In any case, Union has indicated that it would comply with the spirit of the ARC, for example, by paying a negotiated rate that is comparable to what other shippers pay for NEXUS transportation capacity.[55]

Enbridge has no affiliate relationship issues related to the NEXUS project.

With respect to impacts on retail competition and on existing transportation pipeline facilities, the applicants provided some evidence on these issues in accordance with the Guidelines. Enbridge stated that NEXUS will have a positive impact on retail competition as utilities and marketers alike will benefit from additional supply options at the Dawn hub. Enbridge also stated that there is no expectation that NEXUS will result in any significant impacts on existing pipeline facilities that could affect Ontario consumers.[56] Union specifically discussed the risks of NEXUS to the TransCanada Mainline and stated that the impact of the applicants not renewing long-haul

[52] Guidelines at p. 5 (Part V).
[53] EB-2015-0166 / EB-2015-0175, Oral Hearing Transcripts, Volume 1, November 13, 2015 at p. 65.
[54] *Supra* note 2; EB-2015-0166 / EB-2015-0175, Union Pre-Filed Evidence, Exhibit A at p. 45; EB-2015-0166 / EB-2015-0175, Union Reply Argument Summary, December 2, 2015 at p. 22.
[55] EB-2015-0166 / EB-2015-0175, Union Reply Argument Summary, December 2, 2015 at pp. 22-23.
[56] EB-2015-0166 / EB-2015-0175, Enbridge Pre-Filed Evidence, Exhibit A / Tab 3 / Schedule 1 at pp. 42-43.

transportation was already contemplated and addressed in the Mainline Settlement Agreement.[57] No other parties raised any concerns on this issue.

Findings

The OEB finds that Union's commitment to comply with the spirit of the ARC even though not technically an affiliate of NEXUS Gas Transmission, LLC is a reasonable approach to any issues that might arise as a result of Union's parent's interest in NEXUS.

The OEB has no concerns with the impact that the NEXUS pipeline will have on retail competition or existing pipeline facilities.

[57] EB-2015-0166 / EB-2015-0175, Union Pre-Filed Evidence, Exhibit A at p. 52.

6 COST AWARDS

The OEB may grant cost awards to eligible parties pursuant to its power under section 30 of the *Ontario Energy Board Act, 1998*. When determining the amount of the cost awards, the OEB will apply the principles set out in section 5 of the OEB's *Practice Direction on Cost Awards*. The maximum hourly rates set out in the OEB's Cost Awards Tariff will also be applied. The OEB notes that filings related to cost awards shall be made in accordance with the schedule set out below.

7 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Union and Enbridge are granted pre-approval for the cost consequences of their respective long-term transportation contracts for capacity on the NEXUS pipeline.

2. Intervenors shall file with the OEB, and forward to Union and Enbridge, their respective cost claims by **January 7, 2015**.

3. Union and Enbridge shall file with the OEB, and forward to intervenors, any objections to the claimed costs by **January 21, 2015**.

4. Intervenors shall file with the OEB, and forward to Union and Enbridge, any responses to any objections for cost claims by **January 28, 2015**.

5. Union and Enbridge shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

DATED at Toronto December 17, 2015

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

TAB 3 - Enbridge Gas Distribution Inc. (Re), 2014 LNONOEB 41, OEB Decision dated January 30, 2014, Nos. EB-2012-0433, EB-2012-0451, EB-2013-0074

Enbridge Gas Distribution Inc. (Re), 2014 LNONOEB 41

Ontario Energy Board Decisions

Ontario Energy Board

Panel: Cynthia Chaplin, Presiding Member and Vice Chair; Marika Hare, Member; Peter Noonan, Member

Decision: January 30, 2014.

Nos. EB-2012-0433, EB-2012-0451, EB-2013-0074

2014 LNONOEB 41

IN THE MATTER OF an Application by Union Gas Limited Leave to construct the Parkway West Project IN THE MATTER OF an Application by Union Gas Limited Leave to construct the Brantford-Kirkwall/Parkway D Project IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. Leave to construct the GTA Project 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.

(221 paras.)

Table of Contents

Appendices

DECISION AND ORDER

1. Introduction

1 Union Gas Limited and Enbridge Gas Distribution Inc. filed three applications with the Ontario Energy Board requesting approval to construct major system expansion projects.

2 The projects include natural gas pipelines, compressor stations and related facilities. According to Union and Enbridge, the projects are needed to respond to system demands, to diversify their supply portfolios, to address short haul market access requirements for natural gas transportation, and to address integrity issues on Enbridge's distribution system. The applications were filed separately, but the Board combined the proceedings and heard them together.

3 The OEB Act requires the Board to consider the public interest when deciding whether to grant leave to construct. For the reasons set out below, the Board concludes that the applications for leave to construct are in the public interest and the projects are approved, subject to various conditions. In determining the public interest, the Board has considered a number of factors which are addressed further in the findings in this decision.

1.1 The Applications

4 Union made two applications. The Parkway West Project (EB-2012-0433) involves the installation of a standby compressor along with 740 meters of natural gas pipeline and associated facilities, all in the Town of Milton. These requests were made under sections 90 and 91 of the Act. Union estimated the total cost for the Parkway West Project at $219 million. Union also requested ***pre-approval*** for recovery of the costs of the project and an accounting order to establish the Parkway West Cost Deferral Account. These requests were under section 36 of the Act. A map of the Parkway West Project is attached in Appendix D.

5 Union's second application, the Brantford-Kirkwall/Parkway D Project (EB-2013-0074), involves the construction of 13.9 km of NPS 48 pipeline and associated facilities between the City of Cambridge and the City of Hamilton and the installation of a new compressor at the Parkway West site. These requests were made under section 90 and 91 of the Act. Union estimated the total cost of the Brantford-Kirkwall/Parkway D Project at $204 million. Union also requested ***pre-approval*** for the recovery of the costs of the Brantford-Kirkwall/Parkway D Project, and an accounting order to establish the Brantford-Kirkwall/Parkway D Deferral Account. Union also sought ***pre-approval*** of the cost consequences of two ***long-term*** short-haul transportation contracts on the TransCanada system. A map of the Brantford-Kirkwall/Parkway D Project is attached in Appendix F.

6 Enbridge's application, the GTA Project (EB-2012-0451), involves the construction of two segments of natural gas pipeline, and associated facilities, in and around the City of Toronto. Segment A is approximately 27 km long and would be located in the Town of Milton, the City of Mississauga and the City of Toronto. Segment B is approximately 23 km long and would be located in the City of Vaughan, the City of Markham, the City of Toronto and the Town of Richmond Hill. These requests were made under sections 90 and 91 of the Act. The approximate cost of Enbridge's GTA Project is $686.5 million. Enbridge is also seeking approval, under section 36 of the Act, for its proposed Rate 332 methodology for transmission services along Segment A. A map of the GTA Project is attached in Appendix H.

7 Union's Brantford-Kirkwall/Parkway D Project and Segment A of Enbridge's GTA Project would together increase the capacity on the Dawn-Parkway system and facilitate new contracting options on the TransCanada system. TransCanada intends to apply to the National Energy Board ("NEB") for an additional pipeline project, the King's North project, which together with the Union and Enbridge sections would remove a current bottleneck in the overall system. The interrelationships among these projects are discussed later in this decision. A map showing all the projects is attached in Appendix B.

1.2 The Hearing

8 The Board conducted an oral public hearing. There were 39 intervenors, including ratepayer representatives, landowners, municipalities, environmental groups, First Nations, gas shippers, and others. The Board also received four Letters of Comment. A complete list of intervenors, more information about the Letters of Comment, and further details regarding the proceeding are set out at Appendix A.

9 Seven intervenors filed evidence. Gaz Métro Limited Partnership ("GMi") filed evidence in support of the projects. The City of Markham and Markham Gateway each filed evidence regarding potential adverse impacts on future land use from the Enbridge project. Their concerns were subsequently resolved and they did not oppose the application.

10 The Council of Canadians ("COC") opposed the projects and filed expert evidence prepared by Dr. Anthony Ingraffea, Ms. Lisa Sumi, and Mr. David Hughes on shale gas production and related environmental and gas market issues. Environmental Defence and Green Energy Coalition ("GEC") also opposed the projects (in whole or in part), and each filed expert evidence related to Demand Side Management ("DSM") as an alternative to further infrastructure. GEC filed evidence by Mr. Paul Chernick from Resource Insight Inc., and Mr. Chris Neme and Mr. Jim Grevatt from Energy Futures Group. Environmental Defence filed evidence prepared by Mr. Ian Jarvis, Ms. Wen Jie Li and Ms. Gillian Henderson from Enerlife Consulting.

11 Before the oral hearing began, significant conflict arose between TransCanada and the eastern distributors (Union, Enbridge and GMi). TransCanada and Enbridge had entered into a Memorandum of Understanding ("MOU") relating to capacity on Enbridge's proposed GTA Segment A pipeline. However, when the terms were revealed, Union and GMi objected and brought a motion to enforce the Board's *Storage and Transportation Access Rule*. That dispute led directly to Enbridge terminating the MOU. Subsequently, the parties initiated civil litigation and proceedings at the NEB. The eastern distributors applied to the NEB under Section 71 of the *National Energy Board Act* to enforce service obligations against TransCanada, while TransCanada, in turn, adopted a position opposing the applications before this Board, including the filing of evidence, and filed a law suit against Enbridge. However, on the eve of the oral hearing the applicants announced that TransCanada and the three eastern distributors had entered into an agreement which became known as the "Settlement Agreement". This agreement, while entered into evidence, was not negotiated under the auspices of this Board's settlement process. The parties to the agreement intend for TransCanada to submit it to the NEB for approval. As part of the settlement, the litigation before the NEB and the courts was withdrawn and TransCanada ultimately supported the applications before this Board.

12 The Settlement Agreement is an important development in the evolution of the pipeline transportation network in Ontario. It is intended to provide stability to the commercial relationships between the eastern distributors and TransCanada. It seeks to provide a basis for the eastern distributors to access new sources of supply while ensuring that the financial viability of the TransCanada system is not threatened by decontracting.

13 Stable commercial relationships between TransCanada and the eastern distributors are desirable from a public policy perspective. This Board has, in the past, encouraged Union, Enbridge and TransCanada to cooperate in matters relating to the evolution of the pipeline system serving Ontarians. To the extent that this Settlement Agreement is responsive to the Board's previously expressed sentiments, the parties to the agreement are to be commended for their ability to seek solutions that enhance the prospects for optimal commercial outcomes consistent with the public interest.

14 At the same time, this Board must remain cognizant of the limitations surrounding its own responsibilities. The NEB has the jurisdiction to approve, or reject, the Settlement Agreement and any of its specific elements. It would therefore not be appropriate for the Board to determine whether the Settlement Agreement should be approved. The cost consequences of the Settlement Agreement on Ontario ratepayers, if it is approved by the National Energy Board, will be reviewed by the Board in a subsequent proceeding.

15 The Union and Enbridge projects are interrelated, and in some cases interdependent. The projects are also related to facility expansion on the TransCanada system. Although the applications were combined into one proceeding, the Board will set out its findings for each application separately. The findings address the following major public interest considerations for each application:

* Need and Alternatives
* Cost, Economic Evaluation, and Rate Impact
* Environmental, Technical and Safety Issues
* Landowner Matters
* Aboriginal Consultation
* Conditions of Approval

16 The interrelationships between the applications are addressed primarily under the Conditions of Approval.

2. Union's Parkway West Project (EB-2012-0433)

2.1 Need and Alternatives

17 Union's Parkway West Project involves the construction of facilities on a new site, directly across from the existing Parkway Station. Union is proposing the addition of a compressor for the discharge volumes that flow through Parkway, an additional pipeline connection to Enbridge, and upgrades to existing Union transmission pipelines and other required infrastructure. This project would provide what is known as "loss of critical unit coverage". Loss of critical unit coverage requires that at a minimum, there is enough spare horsepower available to meet demand in the event that the single biggest compressor fails. Hence, the compressor is termed an "LCU compressor".

18 Union justifies the project on the basis that Parkway is essential to natural gas flow in Ontario, and that the addition of an LCU compressor will ensure continued reliability. Union's evidence is that a major failure at Parkway would not allow Union to meet its contractual commitments and that the addition of the LCU compressor will therefore mitigate significant operational risk. Union noted that Parkway is the only site on the Dawn-Parkway System which does not have loss of critical unit coverage.

19 Union reviewed eight alternatives to meet the objectives of the Parkway West Project, including physical alternatives and contracting for services on other pipeline systems. Union also met and consulted with stakeholders to review the options. Union concluded that there are no viable alternatives that can provide reliability and resilience for its Parkway deliveries into the TransCanada system as effectively and cost efficiently as the LCU protection proposed through the Parkway West Project.

20 Most parties agreed that the LCU compressor is needed in order to provide added reliability and security to the Dawn-Parkway System and that there were no reasonably viable alternatives. Parties noted that the potential risk of an outage is significant and would have detrimental effects on a large number of customers and that the proposed Parkway West Project addresses these concerns.

21 Building Owners and Managers Association - Toronto ("BOMA") and COC did not support the Parkway West Project. GEC opposed Union's applications generally, but indicated that the LCU compressor might be an exception to its general position.

22 BOMA submitted that it was unnecessary to construct both the LCU compressor and the Parkway D compressor (which is part of the Brantford-Kirkwall/Parkway D Project), and that one new compressor should be satisfactory to address the reliability and growth concerns. Union disagreed and noted that the two different purposes (growth and reliability) cannot be met by a single compressor: Parkway D is required for load growth whereas the LCU compressor provides the reserve capacity necessary to cover off the failure of any of the other units at the facility (including Parkway D). Union submitted that there was no evidence on the record that supports BOMA's position.

23 COC opposed all of the applications, but its concerns were focused on the new sources of supply the other projects facilitate. Union responded that COC's general argument against the applications does not apply to the Parkway West Project.

Board Findings

24 The Board finds that the evidence supports the need for the Parkway West Project and that there is no superior alternative.

25 The evidence clearly shows that the lack of LCU capacity at Parkway West represents a system reliability weakness in the Union system. Parkway West is the only major station on the system that lacks LCU capacity and it is an essential gateway for not only the Union system but for services to the Enbridge system and transportation for other shippers within and beyond Ontario. A compressor failure at Parkway, in the absence of adequate LCU capabilities at that point, could have profound ramifications for the provision of gas service to central and eastern Ontario, as well as Quebec and other markets. No party identified any reasonable or practical alternative to the construction of an LCU compressor.

26 BOMA recommended the construction of a single compressor as an alternative to the LCU project, noting that Union planned to construct an additional compressor as part of the Brantford-Kirkwall/Parkway D Project. As the Board understands the argument of BOMA, one large compressor could provide transmission capacity on the Brantford-Kirkwall segment as well providing LCU capability should an outage occur at Parkway. In BOMA's view, eliminating the second compressor would provide substantial cost savings.

27 The Board does not agree with BOMA's analysis. The evidence is that an LCU compressor provides additional incremental capacity that can be quickly deployed to backstop the system when an outage occurs at one of the other compressors. The evidence shows that whether or not the Parkway Compressor D is built, separate LCU protection is warranted. To the extent Parkway D is justified on the basis of growing demand (which is addressed elsewhere in this decision) it cannot provide LCU coverage. Union needs to be able to replace the single largest unit in service at Parkway should an outage occur, regardless of the number of existing operational compressors at Parkway.

28 COC also expressed opposition to Union's LCU project in general terms, but its objections related more to its opposition to the extraction of shale gas[1] through the hydraulic fracturing process, and concerns about reliance on U.S. rather than Canadian sources of supply. These issues are not relevant to the issue of building an LCU compressor at Parkway West.

2.2 Project Costs, Economic Evaluation and Rate Impact

29 The total estimated Parkway West Project cost, including contingencies and interest during construction, is $219 million, and the largest full-year revenue requirement is approximately $17.7 million. Union sought ***pre-approval*** for the recovery of the project costs.

30 The Board's economic feasibility requirements for transmission and distribution pipelines are outlined in E.B.O. 134 and E.B.O. 188. These requirements relate to system expansion projects which will result in incremental revenues. Since the Parkway West Project is not a system expansion project and does not result in incremental revenues, it is not subject to these economic feasibility tests. As a result, Union did not conduct an economic feasibility analysis.

31 Based on the current Board approved allocation of Dawn-Parkway costs, 16% of the project costs would be allocated to in-franchise rate classes and 84% of the costs would be allocated to ex-franchise rate classes. Union is not proposing any changes to the allocation of Dawn-Parkway transmission system costs, including the allocation of Parkway costs, as a result of the Parkway West Project.

32 Union's proposal to allocate costs directly attributable to the Parkway West Project between in-franchise and ex-franchise rate classes using the current approved allocation method for Dawn-Parkway transmission costs, along with consequential shifts in the allocation of indirect costs and taxes, results in a small rate reduction for in-franchise rate classes. The average Rate M1 residential customer in Union South and Rate 01 customer in Union North would experience a rate reduction of about $0.84 per year and $0.33 per year, respectively. Costs allocated to ex-franchise customers would increase by $18.6 million. The M12/C1 Dawn-Parkway rate would increase to $0.089 GJ/day from the current $0.078 GJ/day.

33 Most parties took no issue with the estimated costs and rate impacts associated with the Parkway West Project. However some objections were raised. Also, a number of parties raised concerns with respect to Union's request for cost ***pre-approval***. The following issues are addressed by the Board:

* Treatment of site costs
* Allocation of project costs
* ***Pre-Approval*** of the costs

Treatment of Site Costs

34 Union has attributed the full costs of the Parkway West site to the Parkway West Project, even though part of the site is to be used for the Parkway D compressor, which is part of Union's Brantford-Kirkwall/Parkway D Project. Union maintained that the same land and facilities are required for the Parkway West Project, whether or not the proposed Parkway D compressor is constructed. Union also noted that the bill impacts are the same regardless of how the costs are allocated between the two projects.

35 Energy Probe and School Energy Coalition ("SEC") argued that Union's allocation of Parkway West site development costs are not appropriate. Energy Probe argued that site development costs should be allocated between the two projects. SEC submitted that even if the rate impact of allocating some site development costs to the Brantford-Kirkwall/Parkway D Project is virtually nothing, as claimed by Union, proper cost allocation between projects should be followed and half of the Parkway West site development cost ($51 million) should be allocated to the Brantford-Kirkwall/Parkway D Project.

36 Union responded that attributing half of the Parkway West land and site development costs to the Brantford-Kirkwall/Parkway D Project is not consistent with the Discounted Cash Flow ("DCF") analysis, which is an incremental cost approach. Union noted that even though the two projects are concurrent, in principle the investment in Parkway D is an incremental decision, independent of Parkway West. Union maintained that the same land and facilities are required for Parkway West, whether or not Parkway D is required.

Board Findings

37 Union took the position that it would have purchased and developed the same sized site regardless of whether its plans contemplated the construction at the present time of one or two compressors. However, Union acknowledged that the size of the site was driven by anticipated future growth. Thus, the size of the proposed site and the land and development costs are not exclusively related to system reliability.

38 Although the evidence shows there is also a component of land acquisition that is related to future growth, the allocation of the site costs is moot because the Board is approving both Union projects and the evidence is that the allocation of the site costs has no impact on rates. Given the coincident nature of the projects, and the fact that there is no rate impact, more granular cost allocation is of limited significance.

Allocation of Project Costs

39 Association of Power Producers of Ontario ("APPrO") questioned whether all M12 shippers and Union South in-franchise customers should be paying costs for added reliability, or whether those customers requesting and directly benefiting from LCU protection should bear the costs. APPrO submitted that Enbridge's small volume customers are the primary beneficiary of the increased reliability because of the company's location and its reliance on storage and gas supplies originating from Dawn and Niagara. APPrO noted that its members are the first customers to be curtailed in the event of an emergency. Union responded that LCU coverage reduces the risk of a major failure at Parkway and thus reduces the risk of all types of customers losing gas services, including all gas-fired power generators.

40 The City of Kitchener ("Kitchener"), a direct customer of Union, also argued that the costs for the Parkway West Project should be recovered from those customers benefitting from the project. In Kitchener's view, it does not benefit from the project and it should not be required to bear any of the associated costs. Kitchener proposed that the cost allocation methodology for the LCU compressor should be reviewed in a separate, consultative process. Union responded that Kitchener's argument overlooks the benefits it and others receive as a result of the project. In Union's view, these benefits include a Dawn-Parkway system that remains as fully contracted as possible, and maintaining and increasing the health and liquidity of the Dawn Hub, which benefits all parties that buy or sell gas at Dawn. Union also maintained that the Dawn-Parkway System is integrated, with different specific system additions benefitting specific customers differently. Union reiterated that the proposed cost allocation methodology follows the current, Board-approved methodology which is aligned with the principle of cost causality.

Board Findings

41 The Board accepts Union's proposal that the current Board-approved cost allocation methodology should be used to allocate the costs of the project to Union's rate classes.

42 APPrO suggested that large customers will obtain minimal benefits from the installation of the LCU compressor because they are curtailed first in the event of a service outage. However, Union's perspective, with which the Board agrees, is that enhanced reliability reduces the risk of curtailment -- which is of particular benefit to large customers who would otherwise be curtailed first. Therefore, the Board is of the view that, in general, larger customers will obtain a benefit from enhanced system reliability.

43 Kitchener argued that it would derive no benefit from the provision of LCU capacity at Parkway from an operational or reliability perspective because the City of Kitchener is serviced by Union from its Owen Sound lateral, which is upstream of Parkway. Kitchener argued that the cost allocation methodology should be revised so that customers upstream of Parkway West do not bear the costs of the Parkway West LCU compressor. Union responded that there are system-wide benefits from high utilization and liquidity of Dawn -- both of which Union considers to be aspects of reliability. Union also argued that the Dawn to Parkway system is an integrated gas transmission and distribution system.

44 While Kitchener may not be directly affected by a compressor outage at Parkway West, the Board is nevertheless of the view that Union's investments are intended to advance an important public purpose -- the provision of a reliable gas transportation system within Ontario. The need for new facilities should be considered in the context of the system as a whole, and not merely from a local perspective. The considerations that Kitchener has raised would require a broader examination of cost allocation principles and their application to the Dawn-Parkway system, which is beyond the scope of this proceeding. Kitchener proposed that the Board conduct a separate review using a consultation process. In the normal course, cost allocation issues are reviewed in cost of service rebasing hearings. The Board finds that Kitchener has not made a sufficiently compelling case to warrant a stand-alone review of this issue, but this issue could be raised in Union's next cost of service proceeding.

Pre-Approval of the Costs

45 Union's application includes a request for ***pre-approval*** of the project costs and their inclusion in rates. Union has also applied for approval of a deferral account to capture any variance between the estimated costs and actual costs. Union explained that it is seeking ***pre-approval*** of the recovery of the costs consequences due to the size of the Project, which is the largest in Union's history. Union maintained that it is not able to proceed with the development of the Parkway West Project without reasonable certainty of cost recovery.

46 Union noted that under the settlement agreement for its multi-year Incentive Regulation Mechanism ("IRM"), which the Board approved, the parties agreed to treat major capital additions as Y factors during the IRM period provided that they meet various criteria.[2] Union submitted that the Parkway West Project meets the criteria for Y factor treatment during the IRM period. Union noted that the project exceeds the $5 million annual revenue requirement and $50 million capital cost thresholds, is needed to serve customers and to maintain system safety, reliability or integrity, cannot reasonably be delayed, and is the most cost effective manner of achieving the project's objectives relative to reasonably available alternatives. Union further noted that the Parkway West Project is identified in the IRM settlement agreement as an example of a project that will be evaluated during the IRM period. Union maintained that the parties to the IRM settlement agreement agreed that the Parkway West Project meets the criteria, provided there is no material change made by the Board.

47 APPrO, London Property Management Association ("LPMA") and SEC supported Union's request noting that the project will primarily be paid for by ex-franchise customers, ***pre-approval*** is an efficient use of regulatory time, and the Parkway West Project meets the criteria for Y factor treatment outlined in the IRM settlement agreement. These parties also agreed that the Parkway West Project deferral account should be established. APPrO submitted that ***pre-approval*** of the costs should only be granted up to the current cost estimate of $219 million.

48 Board staff, BOMA, Canadian Manufacturers and Exporters ("CME"), Consumers Council of Canada ("CCC"), Energy Probe and Federation of Rental-housing Providers of Ontario ("FRPO") opposed Union's request for ***pre-approval*** for various reasons. Board staff submitted that Union does not require an additional layer of assurance through the leave to construct application in order to recover its costs. Board staff noted that Union's IRM process ensures that Union has the appropriate opportunity to include the revenue requirement associated with the projects in a future IRM application, making ***pre-approval*** unnecessary. FRPO and Energy Probe provided similar submissions. BOMA submitted that ***pre-approval*** is not appropriate as it is impossible to conduct a proper prudence review in advance of any expenditures being made. Both CCC and CME made similar submissions to BOMA's, arguing that the prudence of actual costs incurred should be considered in the context of a rate proceeding. CME noted that Union is already entitled to apply to include the Parkway West revenue requirement into rates in a subsequent IRM proceeding. No party opposed the approval of the requested Parkway West deferral account.

Board Findings

49 The Board approves the recovery of the costs of the Parkway West Project, subject to two limitations set out below. This project and the Brantford-Kirkwall/Parkway D Project are the largest, in financial terms, which Union has undertaken. Union emphasized that ***pre-approval*** of costs was a prerequisite for the company to undertake the project, as the company considered that it was too risky to undertake the project in the absence of assurances that the costs would be recovered in rates.

50 While some of the intervenors supported the request several did not, generally arguing that Union does not require an additional layer of assurance with respect to costs and that the terms of the IRM settlement agreement are sufficient. However, given the magnitude of the expenditure that is proposed, the Board is of the view that Union's request is reasonable and consistent with the overall regulatory structure. Recovery of these costs is specifically contemplated in the IRM settlement agreement approved by the Board. This situation is also similar to traditional cost of service ratemaking, in which the costs of projects approved in leave to construct proceedings typically flowed into rates with only significant cost variances being subjected to examination in the subsequent rates proceeding.

51 The Board's approval of cost recovery is subject to two important limitations. First, the Board is only pre-approving recovery of costs up to the current estimate of $219 million. None of the parties took issue with Union's cost projection of $219 million for the Parkway West Project and the Board considers the cost projection to be a reasonable estimate in the circumstances. Second, the costs will only be incorporated into rates when the project is completed and in-service. This provides reasonable assurance that ratepayers are not exposed to costs prematurely.

52 No party took specific issue with Union's request for a deferral and variance account, and the Board finds that it is appropriate to use an account to track any difference between the estimated cost and actual cost. The request for a deferral and variance account is granted. The Board wishes to emphasize that any excess costs over and above the pre-approved amount will be examined at Union's next rates application after the completion of the project. As evidence tendered in the proceeding showed, Union has experienced cost overruns on several of its past compressor projects and therefore the Board will be looking to the utility to rigorously control its expenditures on this project.

2.3 Environmental, Technical and Safety Issues

53 Stantec Consulting Ltd. prepared the environmental reports for the Parkway West Project. The results in the environmental reports indicate that the location of the proposed Parkway West Project is environmentally acceptable and no significant cumulative effects are anticipated. Union maintained that by following its standard construction practices and adhering to the mitigation measures identified in the environmental reports, construction of the Parkway West Project will have negligible impacts on the environment. Union noted that the Ontario Pipeline Coordinating Committee's review raised no significant issues.[3]

54 Union provided detailed evidence regarding the design, installation and testing of the project. Union noted that all work would be done in accordance with the requirements of Ontario Regulation 210/01, *Oil and Gas Pipeline Systems* under the *Technical Standards and Safety Act, 2000*.

55 There were no issues raised by parties with respect to environmental impacts or technical and safety requirements.

Board Findings

56 Union has committed to implement all the recommendations in the environmental reports. The Board accepts Union's evidence regarding the environmental assessment and finds that the proposed mitigation and monitoring activities are acceptable and address the environmental concerns. The Conditions of Approval reflect Union's commitments.

57 The Board is also satisfied that the evidence establishes that the pipeline design and specifications are acceptable based on current standards.

2.4 Landowner Matters

58 Union noted that the station property site has been purchased already and there are no outstanding landowner concerns related to the site. Union also noted that for the pipeline segment it will require new permanent and temporary land rights, crossing permits or agreements with Hydro One Networks Inc. and her Majesty the Queen in the Right of Ontario, administered by Infrastructure Ontario. Union has met and discussed the project with Hydro One and Infrastructure Ontario, and with the Ministry of Transportation and 407ETR, who have existing rights in the Highway 407 corridor. Union maintained that although agreements have not been finalized with these entities, no significant concerns have been raised. Union included a proposed form of easement as part of its application.

59 There were no issues raised by parties with respect to landowner matters.

Board Findings

60 Under section 97 of the Act, the Board ensures that the forms of agreement provided to landowners who are located along the approved route of the pipeline are appropriate. The Board determines the appropriate subject-matter of the form of an agreement to be offered to an Ontario landowner, as well as the technical format of the document but not the substance of the agreements, which are left to the landowner and the pipeline company to negotiate. The Board's approval of the form of an agreement thus provides a baseline for the initial offer of an easement agreement to a landowner, and prevents the company from unilaterally resiling from its proffered terms.

61 The Board is satisfied that Union has properly consulted with those landowners directly affected by the Parkway

West Project and that it will continue to do so leading up to and throughout construction. The Board has examined the form of easement agreement provided by Union and finds that it is acceptable and it is therefore approved.

2.5 Aboriginal Consultation

62 Union indicated that it is not aware of any outstanding issues raised by First Nations or Métis organizations. Union notified First Nation and Métis organizations by letter regarding the Parkway West Project on two separate occasions. Union noted that it is conducting formal consultation with Six Nations of the Grand First Nation, Mississaugas of the New Credit First Nation, and Métis Nation of Ontario with respect to the Parkway West Project. Union noted that during construction, it will have inspectors in the field who are available to First Nations and Métis organizations as primary contacts to discuss and review any issues that may arise during construction. When the necessary archaeological assessments for the project are complete, the company has committed to consulting with and providing the result of the surveys to any First Nations or Métis Nations organizations upon their request as part of the environmental review process.

63 There were no issues raised by First Nations or Métis organizations, or by other parties with respect to Union's consultation with First Nation or Métis organizations.

Board Findings

64 The Board is satisfied that the evidence establishes that Union has made appropriate efforts to consult with affected First Nations and Métis organizations with respect to the Parkway West Project. The Board expects Union to continue to proactively consult with affected First Nations and Métis organizations, as appropriate, throughout the construction phase of the project. The Conditions of Approval reflect Union's commitments as indicated in the prior section,.

2.6 Conditions of Approval

65 Union accepted the standard conditions of approval for Section 90 and Section 91 applications as proposed by Board staff, with one exception. Union proposed that Condition 1.2 be modified so that leave to construct is not terminated until December 31, 2015 as opposed to December 31, 2014.

66 Union submitted that no other conditions are required as the Parkway West Project is independent of both the Brantford-Kirkwall/Parkway D Project and Enbridge's GTA Project. Most parties agreed that this project was independent of the other two projects, although APPrO proposed that if the other projects are not approved, then the Board should delay approval of the Parkway West Project until the Parkway facilities accommodate a greater share of the Ontario volumes. In addition, APPrO proposed that ***pre-approval*** of the costs should be conditional on approval of the other projects in the combined proceeding.

67 Energy Probe submitted that additional wording should be added to Condition 1.3 and 4.1. The proposed additions are set out in bold below.

> 1.3 Union 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 ("OPCC") review. **Union shall also adhere to the conditions of all other permits, approvals, licences, certificates and easements rights**.

4.1 Union 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.

Board Findings

68 The Board agrees that the standard conditions presented to Union during the hearing should be adopted, with certain modifications. The Board is prepared to accept Union's request for additional flexibility on the timing of the project and will therefore modify Condition 1.2 so that leave to construct will not be terminated until December 31, 2015 as opposed to December 31, 2014. The Board will also modify condition 4.1 by inserting the words "to the Board" for clarification, as was suggested by Energy Probe.

69 The Board finds that this project is independent of the other projects considered in this proceeding. The project is predicated on providing loss of critical unit coverage for the compression at Parkway and increased reliability for the substantial interconnection with Enbridge at Parkway. It is not impacted by pipeline capacity downstream of Parkway or the related projects. Therefore, the Board finds that there is no requirement for a linkage in the Conditions of Approval between this project and the other projects. Consequently, the Board will not adopt APPrO's proposal that ***pre-approval*** of the costs consequences be conditional on approval of the other projects. APPrO's other proposal that approval be delayed is moot because the other applications are being approved.

70 The Board will not accept Energy Probe's proposed modification to Condition 1.3. The various bodies from which Union must acquire approvals, permits, licences and certificates will have their own enforcement powers. The Board concludes that enforcing the approvals of other authorities is not an appropriate role for the Board. In addition, Energy Probe's proposal is legally vague and thus potentially unenforceable.

71 The Conditions of Approval for this application are attached as Appendix C of this decision.

3. Union's Brantford-Kirkwall/Parkway D Project (EB-2013-0074)

3.1 Need and Alternatives

72 The Brantford-Kirkwall/Parkway D project involves the construction of 13.9 km of NPS 48 pipeline to enhance capacity between the existing Brantford Valve Site and the Kirkwall Custody Transfer Station. The project also includes the addition of the Parkway D compressor, including measurement and associated facilities. The project would allow Union to deliver new contracted volumes to Enbridge, GMi, and the U.S. Northeast and to provide Dawn-based natural gas supply to its customers. Union developed the proposal in consultation with Enbridge, TransCanada and GMi and it complements the projects being developed by Enbridge (i.e. Segment A of the GTA Project) and TransCanada (i.e. King's North Project).

73 Union justified the project on the basis that it will facilitate access to gas supplies from eastern U.S. sources (primarily the Marcellus and Utica shale) and will therefore increase security and diversity of supply for its in-franchise customers, particularly in the Union North area. Union also claimed that the project will produce significant gas supply savings for Union North sales services and bundled direct purchase customers. These savings were estimated at $144 million over the next 15 years.

74 Union maintained that the project will support the continued growth of the Dawn Hub, which would increase market depth and liquidity and the price competitiveness of gas supply options for Ontario customers over the ***long term***.

75 Union considered both facility and non-facility alternatives to the project. Union concluded that non-facility alternatives (e.g. winter peaking service) were not viable due to the large size of the forecast 2015/2016 capacity shortfall (approximately 557 TJ/day) and the fact that the shortfall is associated with firm incremental demand. Union also considered pipeline looping and compression alternatives. These were considered separately and in various combinations. Union concluded that across all pipeline and compressor scenarios, the proposed Brantford-Kirkwall/Parkway D Project ranked the lowest (i.e. best) in terms of capital cost per unit of capacity.

76 Most parties supported the application and agreed that there was no better alternative. CME noted that the expansion of the entire pathway from Parkway to Maple appears to be necessary to meet market demands. CME also submitted that the market will likely suffer if any component of the pathway, which includes Union's Brantford-Kirkwall pipeline, Enbridge's Segment A pipeline and TransCanada's proposed King's North pipeline, is not built or is significantly delayed.

77 Three parties opposed the project: BOMA, GEC and COC. These parties argued that the Board should not approve any of the projects in the combined proceeding.

78 BOMA argued that given the uncertainty as to whether the NEB will approve the Settlement Agreement, it would not make sense for the Board to approve any transmission related components of the proposed projects, including Union's Brantford-Kirkwall/Parkway D application. Further, BOMA viewed the overall increase of compression capacity at Parkway West as excessive and not required at this time. BOMA submitted that if the Settlement Agreement is approved, there appears to be sufficient compressor horse power at Parkway with the addition of the proposed LCU compressor to secure the forecast growth and provide LCU protection.

79 GEC argued that the applicants have not established the need or demonstrated the economic value for any of the projects in the combined proceeding, and have not properly investigated lower cost alternatives to the proposed capital expansions, including DSM. Union responded that there is no evidence that DSM initiatives could significantly decrease demand in the near or medium term. Union noted that even if demand did decrease, that would in no way undermine the critical importance of achieving diversity and security of supply for Ontario which is achieved through the Brantford-Kirkwall/Parkway D Project.

80 COC submitted that the group of projects is not in the public interest because there are significant supply risks associated with the Marcellus and Utica shale gas resources as well as significant adverse environmental impacts. COC argued that continued reliance on Western Canadian Sedimentary Basin ("WCSB") supplies was the preferred alternative from the perspective of environmental impact, security of supply and cost.

81 Union responded that placing sole reliance on supply from the WCSB would be contrary to the realities of the market and undermine the objective of seeking security and diversity of supply. Union also noted that doing so would be contrary to the Board's findings in the Natural Gas and Electricity Interface Review regarding the importance of the Dawn Hub.[4] In that decision the Board held that "it is in the public interest to maintain and enhance the depth and liquidity of the market at the Dawn Hub as a means of facilitating competition."

Board Findings

82 The Board finds that the evidence supports the need for the Brantford-Kirkwall/Parkway D Project and that there is no superior alternative which has been presented.

83 The project is part of a group of projects, including Enbridge's GTA Segment A pipeline and TransCanada's proposed King's North pipeline that will facilitate greater flows of mid-continent natural gas into Dawn for transportation to downstream markets. The projected benefits of these projects stem from an enhanced diversity of supply, gas costs savings, and enhanced liquidity at Dawn.

84 The Brantford-Kirkwall/Parkway D Project received substantial support from Union's ratepayer groups. However, BOMA, COC and GEC opposed the project.

85 BOMA's concerns relate mostly to the timing of the project and to concerns about the uncertainty around the upcoming NEB proceeding, which will consider the Settlement Agreement. However, the Board finds that this concern can be effectively addressed by conditioning the approval, particularly in respect to timing. This issue is discussed in further detail below in the Conditions of Approval section. BOMA also proposed that only one compressor be installed, instead of both the Parkway D compressor and the LCU compressor. However, that argument has previously been addressed in this decision in relation to the Parkway West Project.

86 GEC focused on natural gas conservation as a preferred alternative, primarily through DSM programs. In its argument, GEC focused primarily on the Enbridge GTA reinforcement projects but stated that its views generally applied to Union as well. However, GEC did not advance specific arguments against the Brantford-Kirkwall/Parkway D Project based on evidence in the proceeding. The issue of DSM as an alternative is discussed later in this decision in the context of the Enbridge application. There was no evidence that DSM measures would obviate the need for the Brantford-Kirkwall/Parkway D Project. GEC's own witness, Mr. Chernick, did not take a position on Union's applications, but indicated that because the projects relate to switching gas supplies the need for the projects would not be affected by load reductions. As he stated in testimony:

> "I was asked to look at the feasibility and benefits of avoiding additions through load reductions. And since the justification for Segment A and some of the other facilities had to do with switching gas supplies, it really wouldn't have been affected by load reductions."[5]

87 Similarly, the other evidence related to DSM alternatives (Mr. Neme and Mr. Jim Grevatt on behalf of GEC and Mr. Ian Jarvis, Ms. Wen Jie Li and Ms. Gillian Henderson from Enerlife Consulting on behalf of Environmental Defence) related only to the Enbridge application. The Board finds that there is no evidence that DSM measures would provide a superior alternative to the Union project.

88 COC opposed all of the applications. COC submitted that the applicants have underestimated the risks of diversifying supply with shale gas while overestimating the benefits. COC also took the position that Canadian gas is preferable to a reliance on U.S. sourced gas. However, Ontario is situated within a continental energy market which has developed over a substantial period of time. The integrated nature of the gas market has brought significant cost and reliability benefits to Ontario consumers. Further, the evidence in the proceeding is that shale production is expected to remain strong and there are no regulatory impediments to ongoing production where it is currently taking place. It is the Board's view that while uncertainties exist for all supply sources in terms of future cost and availability, it is widely acknowledged, including by this Board in prior decisions, that supply diversification enhances reliability and brings cost benefits through enhanced competition.

89 COC also opposed the project on the basis that it enables greater use of an environmentally harmful source of supply -- shale gas -- which is produced through hydraulic fracturing. COC compares the Board's position to the considerations before the United States Department of State, and the President of the United States in the case of TransCanada's proposed Keystone XL Pipeline. COC argued that environmental impacts of shale production should be taken into account when considering the applications.

90 The Board does not agree with COC's analysis for two reasons. First, there was evidence in this proceeding that conventional WCSB gas supplies are being replaced with shale gas from western Canada and therefore shale gas supplies will likely enter the Ontario market from Canada as well. In addition, in an integrated pipeline system there are multiple paths that gas can take; at any given time gas in the proposed pipeline could come from multiple sources, including conventional supplies. Second, there are currently no regulations in Ontario or at the Canadian federal level which prohibit shale gas production or transportation. There was no evidence that the relevant authorities within the Marcellus or Utica basins, from which the proposed facilities will access gas, are failing to enforce legal standards relating to environmental protection in relation to shale or tight gas production. There is therefore no public policy or regulation governing shale gas production which could form a basis upon which the Board could reasonably deny the application.

3.2 Project Costs, Economic Evaluation and Rate Impact

91 The Brantford-Kirkwall/Parkway D Project is estimated to cost $204 million, comprised of:

* The Brantford-Kirkwall pipeline at a cost of $96 million.
* Parkway D Compressor Station at a capital cost of $108 million.

92 The annual revenue requirement associated with the project reaches approximately $15.9 million in 2018. Union expressed a high degree of confidence in its cost estimates noting that it is further along in the costing process than it has been in other leave to construct applications in which approval was granted by the Board. Union requested ***pre-approval*** of the costs and an associated variance account.

93 In evaluating the economic feasibility of the project, Union used a three-stage analysis in accordance with the Board's E.B.O. 134 *Report on System Expansion*. The report forms the basis of the filing requirements on the economic feasibility test for leave to construct applications for pipeline transmission projects. The Board's *Filing Guidelines on the Economics Tests for Transmission Pipeline Applications* provides further guidance on the proper economic tests to be used, including the details of the discount cash flow analysis.[6] In E.B.O. 134, the Board discusses that if the first stage analysis results in a profitability index ("PI") of 1.0 or greater, no further analysis is required. The second and third stage analyses quantify other public interest factors not considered at Stage 1. Stage 2 includes all other quantifiable public interest information as to costs and benefits, and Stage 3 assesses all other relevant public interest factors plus the results from Stage 1 and Stage 2.

94 Stage 1 of the analysis consists of a discounted cash flow, which identifies the incremental cash inflows and outflows resulting from a project. When evaluating facilities projects, the PI typically should be above 1.0 in order to be considered economic. The PI is calculated by dividing the net present value of the cash inflows by the net present value of the cash outflows. Union's Stage 1 analysis indicates a cumulative net present value of $1.8 million and a PI of 1.01. Union noted that this estimate is conservative for several reasons. First, the gas cost savings included by Union in the estimate reflect an Empress to Dawn basis differential that is higher than that forecasted by TransCanada for the winter 2013/2014 ($0.92/GJ versus $0.64/GJ). Union noted that every 10 cent reduction in the basis differential results in a $2 million increase in gas cost savings. Second, the economics reflect only 15 years of gas cost savings notwithstanding that the Brantford-Kirkwall/Parkway D Project has been evaluated over a 30-year period.

95 Union did not complete a Stage 2 analysis because the Stage 1 NPV is positive. The Stage 3 analysis of other public interest considerations were outlined by Union in its argument-in-chief, based on evidence in the proceeding. Union noted that there are a number of such considerations such as security of supply, contribution to a competitive market, environmental benefits, employment, utility taxes, cost reductions, diversity of supply, and ***long-term*** growth and rate stability.

96 As with its Parkway West Project, Union proposed to use the current Board-approved cost allocation methodology, which allocates costs between in-franchise and ex-franchise rate classes using distance weighted Dawn-Parkway design day demands. On that basis, in-franchise rate classes will be allocated approximately 16% of the costs, with the remaining 84% of costs allocated to ex-franchise rate classes. Union stated that the largest revenue requirement for the project would be $15.9 million, with the following resulting cost allocation impacts:

* An increase of approximately $1.6 million, allocated to Union North in-franchise rate classes
* A reduction of approximately $1.7 million, allocated to Union South in-franchise rate classes
* An increase of approximately $16.0 million allocated to ex-franchise rate classes

97 Union estimated the following rate impacts:

* The average Rate 01 residential customer in Union North would see an increase of approximately $2.80 per year.
* The average Rate M1 residential customers in Union South would see a decrease of approximately $1.12 per year.
* For ex-franchise customers taking M12 Dawn-Parkway transportation service, the M12 rate is expected to increase by approximately $0.003/GJ/d; from $0.078/ GJ/d to $0.081/GJ/d.

98 Parties raised three issues related to project cost, economic evaluation and rate impact:

* Gas cost savings
* ***Pre-Approval*** of the costs
  * ***Pre-Approval*** of the cost consequences of two contracts with TransCanada

Gas Cost Savings

99 One of the key drivers for the economic analysis is the forecasted gas savings. Although shale gas from eastern U.S. sources is expected to be priced at a premium to WCSB supplies, the associated transportation costs are forecast to be lower and this is expected to result in overall net gas cost savings.

100 COC, GEC and BOMA submitted that Union's estimated gas cost savings appear to be overestimated. GEC cautioned that although there may be some gas cost savings initially, those savings will not be realized in the end because under the Settlement Agreement TransCanada will be made whole for any lost revenues due to the shift from long haul to short haul service. BOMA noted that the gas cost savings are based on speculative tolls and commodity price projections. SEC also submitted that the estimated gas savings may be overstated and are uncertain for a number of reasons: the Settlement Agreement is not yet approved; there is uncertainty around the impacts of the TransCanada Energy East project; and there is uncertainty as to how the impacts of converting from long haul to short haul service will be allocated.

101 Union responded that its gas cost savings estimates are conservative. Union noted that it had used a higher differential between the gas price at Empress and Dawn ($0.92/GJ) than the current differential between these two supply points (approximately $0.50/GJ) and the forward market differentials for 2015/16 (approximately $0.60/GJ to $0.70/GJ). Union noted that TransCanada's projection for winter 2013/2014 is currently between $0.64/GJ and $0.77/GJ. Union maintained that, even without the predicted significant savings in gas costs, the Brantford-Kirkwall/Parkway D Project is still in the public interest based on increased security and diversity of supply. Union submitted that the opportunity to develop access to Dawn and Niagara is now, because Ontario needs to ensure that its end users have access to the least expensive natural gas possible. Union agreed with LPMA's argument that the best way to manage the risk of gas cost uncertainty is through supply diversity.

Board Findings

102 The economic analysis of the Brantford-Kirkwall/Parkway D Project hinges to a large extent on the estimated gas cost savings, which are a major driver for a positive NPV. The evidence shows that gas purchased at Dawn is currently more expensive than gas purchased at Empress and it is expected to remain so for the foreseeable future. However, long haul transportation costs from Empress are higher than the cost of short haul transportation services on pipelines that serve Dawn. The Settlement Agreement addresses that issue and provides for an alignment of that differential, in absolute terms, in a manner intended to keep TransCanada whole. The shift from long haul transportation on the TransCanada system to short haul transportation from the new mid-continent shale gas supply fields has created, and will continue to create, lost revenues for TransCanada. The Settlement Agreement provides that the lost revenue will be recovered over time. While it is proposed in the Settlement Agreement that, on a net basis, TransCanada will be largely kept whole, the Board notes that there are several other factors that must be taken into account, including timing differences with respect to payments, which may result in discounts to present values, as well as a fixed contribution to be made by TransCanada, and TransCanada's acceptance of a return on equity that is less than what was awarded to it in the most recent NEB decision (although it will still exceed historical return on equity levels for TransCanada).

103 While Union submits that the net effect is forecast to be gas cost savings to the eastern distributors, the Board is less sure of that outcome. After weighing the various factors noted above, the Board concludes that the delivered gas cost savings on a *final net* landed basis are uncertain. Any revenue shortfall on the TransCanada system caused by the proposed shift to short haul transportation from long haul transportation will be recovered eventually under the terms of the Settlement Agreement. As a result, there may be no enduring transportation savings to offset the gas commodity cost differential.

104 However, the alternative for the eastern distributors under the recent NEB decision is continued uncertainty with respect to access to gas transportation service on the TransCanada system. That results from the fact, recently underscored by the NEB's latest decision on TransCanada tolls, that TransCanada has no legal obligation to serve the public.[7]

105 Therefore it is difficult to come to a firm conclusion about the likelihood of TransCanada costs under the various comparative scenarios as there will always be an element of uncertainty in relation to future economic events. However, the Board accepts as a matter of principle that TransCanada will need to be able to recover its costs in order to continue offering services and to offer new services. The Board concludes that under the most likely scenarios TransCanada will be kept whole, and therefore ratepayers will be no worse off than they would be under the current TransCanada toll regime.

106 Furthermore, Ontario gas consumers will obtain additional certainty through this project concerning their access to alternative supply sources. The project will provide access to more supply and to more sources of supply while retaining market access to existing WCSB supplies. That is a clear benefit to Ontario consumers, and is a positive element in relation to the economic viability of the project. Supply diversity enhances security and has the tendency to lower gas prices from what they would otherwise be if the market continued to rely on fewer sources of supply.

107 COC questioned the certainty of eastern shale supply in light of declining production profiles and potential environmental regulations. The Board accepts that all forecasts are uncertain; indeed forecasts based on current information vary. However, all current forecasts show substantial ongoing total production from eastern mid-continent shale supplies. Future regulations may affect price or volumes, but whether regulations having that effect will be adopted in the future is uncertain. Certainly there is no strong evidence that regulatory action will be taken in the short term which would have the result of significantly diminishing production. Nevertheless, production levels are always sensitive to price and the gas market can be highly volatile. Volatility can be driven by all sorts of factors including the economy, weather, transportation bottlenecks, new drilling technologies, and access to storage. Access to liquid markets and a variety of supply sources (which is facilitated by this project) helps to mitigate those uncertainties and price volatility.

108 The Board concludes that while it cannot firmly determine that Brantford-Kirkwall/Parkway D Project will result in gas cost savings, in the light of the contextual factors, gas cost savings are possible. Even if gas cost savings do not materialize, the project is justified on the grounds of enhanced security and diversity of gas supply, and the contribution that the project will make to enhance a competitive natural gas market in Ontario through increased liquidity at Dawn. The Board notes that the rate impacts are modest and the project has the general support of ratepayer representatives.

***Pre-Approval* of the Costs**

109 As with the Parkway West Project, Union is also seeking ***pre-approval*** of recovery of the cost consequences of the Brantford-Kirkwall/Parkway D Project. The total estimated Brantford-Kirkwall/Parkway D Project costs are $204 million with the largest full-year revenue requirement being approximately $15.9 million. Union also requested approval for a variance account to capture any difference between the estimated costs and actual costs. Union's justification and parties' positions were the same for this project as for the Parkway West Project.

Board Findings

110 Consistent with the finding for the Parkway West Project, the Board will approve the recovery of the cost consequences of the Brantford-Kirkwall/Parkway D Project, subject to two limitations, and the associated variance account. Based on the evidence, the Board concludes that there was no substantive difference between the two projects in relation to this issue and therefore the same reasons apply.

111 As with the earlier finding, the Board will impose two limitations on the cost ***pre-approval***. First, the Board is only pre-approving recovery of costs consequences up to the current estimate of $204 million. The Board finds that this cost estimate is reasonable. Second, costs will only be incorporated into rates when the project is completed and in-service. This provides reasonable assurance that ratepayers are not exposed to facilities costs prematurely.

112 The Board also approves the requested variance account and notes that the same expectations regarding cost control and the future review of cost overruns applies to this project.

Pre-Approval of two contracts with TransCanada

113 Union has requested ***pre-approval*** of the cost consequences of two anticipated TransCanada ***long-term*** short-haul transportation contracts. Union submitted that even though precedent agreements have not been executed with TransCanada, the Board should provide ***pre-approval*** of the cost consequences of those contracts. Union cited several reasons the Board should provide ***pre-approval***, including:

* the contracts are directly tied to and support the construction of new facilities planned by Enbridge and TransCanada, as contemplated by the Board's guidelines;
* there are significant economic benefits (approximately $10 million annually) to ratepayers in Union North;
* the contracts represent significant financial and term commitments by Union; and,
* the term and volume associated with the anticipated contracts are known and the remaining aspects of the contract are standard and will be comparable to other TransCanada precedent agreements executed by Union.

114 Most parties opposed Union's request. Board staff, CME and FRPO submitted that Union's request is not consistent with the Board's *Filing Guidelines for the **Pre-Approval** of **Long-Term** Natural Gas Supply and/or Upstream Transportation Contracts* (the "Guidelines").[8] CME further submitted that the Board should reject Union's request because the contracts do not currently exist. CCC submitted that approval of the contracts should not be provided until both Segment A of Enbridge's GTA Project and TransCanada's King's North Project have been approved.

115 Union responded that no party had suggested that Union should not enter into the ***long-term*** contracts. Union submitted that based on this, it is appropriate for the Board to consider their cost consequences at this time because the Board has all of the required evidence with respect to the anticipated tolls, the terms of the contracts and the transportation paths.

Board Findings

116 The Board will not grant the requested ***pre-approval*** of the cost consequences of the two ***long-term*** contracts with TransCanada.

117 The Guidelines specify that ***pre-approval*** of the cost consequences of ***long-term*** contracts should be limited to those contracts that support the development of new natural gas infrastructure. Although the proposed contracts are related to the new infrastructure proposals, no contract has yet been put in place, nor is there any precedent agreement. The Board has difficulty with the concept of approving the cost consequences of a contract which does not yet exist. How can the Board consider the cost consequences of these proposed contracts when the Board does not know what those costs may be? Union maintained that all the key factors are known, including anticipated tolls. However, in the absence of actual agreements, or even precedent agreements, that information remains highly uncertain. It would be contrary to the public interest to make a decision that is based on an absence, or paucity, of evidence. In addition, there was no cogent evidence to show that the requested approval was crucial to the project.

3.3 Environmental, Technical and Safety Issues

118 Stantec Consulting Ltd. ("Stantec") prepared a route selection and environmental impact report for the Brantford-Kirkwall Pipeline in 2009. Stantec subsequently prepared an addendum to the report in 2013. According to the report, the location of the Brantford-Kirkwall Pipeline is the environmentally preferred route. A mitigation plan has been developed to minimize any potential impacts. Stantec also prepared an environmental report for the Parkway West Compressor Station. The report indicates that the Proposed Parkway West Compressor Station will have minimal effects on the environment and Union plans to follow the mitigation measures that have been recommended. There were no issues raised by parties with respect to the environmental impacts of the pipeline or the compressor.

119 Union stated that the design, installation and testing of the pipeline and station facilities would be done in accordance with the requirements of Ontario Regulation 210/01, *Oil and Gas Pipeline Systems* under the *Technical Standards and Safety Act, 2000*. There were no issues raised by parties with respect to technical and safety requirements.

Board Findings

120 Union has committed to implement all the recommendations of the environmental reports. The Board accepts Union's evidence regarding the environmental assessment of the project, and finds that the proposed mitigation and monitoring activities are acceptable and address the environmental concerns. The Conditions of Approval reflect Union's commitments.

121 The Board is also satisfied that the evidence establishes that the pipeline design and specifications are acceptable based on current standards.

3.4 Landowner Matters

122 Union has purchased the site for the compressor station. For the Brantford-Kirkwall Pipeline, Union has negotiated early access agreements with landowners along the route to conduct all necessary preliminary surveys. Union committed to having all land rights in place prior to construction. Union noted that it will implement a comprehensive program to provide landowners, tenants and other interested parties with information regarding the proposed pipeline. Union included its draft form of easement which will be offered to all affected landowners in the event an easement is necessary.

123 There were no issues raised by parties with respect to landowner matters.

Board Findings

124 Under section 97 of the Act, the Board ensures that the forms of agreement provided to landowners who are located along the approved route of the pipeline are appropriate. The Board determines the appropriate subject-matter of the form of an agreement to be offered to an Ontario landowner, as well as the technical format of the document but not the substance of the agreements, which is left to the landowner and the pipeline company to negotiate. The Board's approval of the form of an agreement thus provides a baseline for the initial offer of an easement agreement to a landowner, and prevents the company from later resiling from its proffered terms.

125 The Board is satisfied that Union has properly consulted with those landowners directly affected by the Brantford-Kirkwall/Parkway D Project and that it will continue to do so leading up to and throughout construction. The Board has examined the form of easement agreement provided by Union and finds that it is acceptable and it is therefore approved.

3.5 Aboriginal Consultation

126 Union indicated that it is not aware of any outstanding issues raised by Métis or First Nations organizations related to the proposed facilities. Union noted that during construction it will have inspectors in the field who are available as primary contacts to discuss and review any issues that may arise. Union will make the necessary archaeological assessments for the project available to any Métis or First Nations organization that requests a copy. Union will undertake construction in accordance with the mitigation measures recommended in the assessment. Board staff submitted that an appropriate mitigation plan has been developed by Union to address any potential issues regarding affected First Nations and Métis organizations.

127 There were no issues raised by other parties with respect to Union's consultation with First Nation or Métis organizations.

Board Findings

128 The Board is satisfied that the evidence establishes that Union has consulted appropriately with affected First Nations and Métis organizations with respect to the Brantford-Kirkwall/Parkway D Project. The Board expects Union to continue to proactively consult with affected First Nations and Métis organizations, as appropriate, throughout the construction phase of the project.

3.6 Conditions of Approval

129 Union accepted the standard conditions of approval as proposed by Board staff, with one exception. Union submitted that the termination date should be December 31, 2016 rather than December 31, 2015.

130 Union acknowledged that this project is related to the Enbridge GTA Project and the planned TransCanada King's North project. Union stated that it will not undertake construction of the Brantford-Kirkwall Pipeline until TransCanada has received approval from the NEB for the King's North Project. However, Union also maintained that the Parkway D Compressor is not dependent on the TransCanada King's North Project, but is required to meet Enbridge's distribution demands.

131 Many parties argued that approval for the Brantford-Kirkwall/Parkway D Project should be conditional on other approvals. Board staff submitted that the timing of the Brantford-Kirkwall/Parkway D Project should be aligned with Segment A of Enbridge's GTA Project and TransCanada's King's North Project so that all projects are in-service at about the same time. Board staff submitted that it would not be appropriate to have facilities complete and in-service but under-utilized, because the associated costs will begin to be recovered from in-franchise customers rather than primarily from ex-franchise customers as contemplated in the proposal. CME and LPMA agreed with Board staff's position.

132 Union responded that it will not begin construction of the Brantford-Kirkwall pipeline until after TransCanada has received approval from the NEB for the King's North Project. However, contrary to Board staff's submission, Union argued that there is no need for the timing of the King's North Project's in-service date to be perfectly aligned with the Brantford-Kirkwall pipeline or Enbridge's GTA Project, and any requirement for perfect alignment could be detrimental. Union noted that short-term delays are not uncommon in building large infrastructure projects like these, but that does not mean that a delay in one project would eliminate the need for the others.

133 Union also submitted that it would set an undesirable precedent for the Board to condone delaying infrastructure projects until all contingencies were eliminated. Union submitted that it and its customers should not have to wait until the NEB approves King's North to proceed with development of the Brantford-Kirkwall pipeline. In the event the Board does impose a condition of approval, Union submitted that the condition should not interfere with:

* Union's ability to incur costs in connection with the development of the proposed Brantford-Kirkwall pipeline leading up to construction; or
* Union's ability to recover its prudently incurred costs for any development work on the proposed Brantford-Kirkwall pipeline, even if the NEB does not ultimately approve the King's North Project.

Board Findings

134 The Board notes that Union has accepted all standard conditions with a proposed revised termination date of December 31, 2016, which is acceptable to the Board.

135 The Board has considered the interrelationships amongst the projects and how appropriate conditions may be used to ensure a rational construction sequence with respect to the approved facilities. The Board will not condition approval of the Brantford-Kirkwall/Parkway D Project on the approval and construction of Enbridge's proposed GTA pipeline Segment A, notwithstanding the relationship between the projects. Such a condition would be moot in the circumstances because elsewhere in this decision the Board has granted Enbridge leave to construct Segment A.

136 However, the Board finds that the Brantford-Kirkwall pipeline and the proposed TransCanada King's North project are interdependent (as Union has acknowledged). Accordingly, the Board will condition approval of the construction of the Brantford-Kirkwall pipeline on the NEB's approval of the TransCanada King's North project. In addition, the Board will condition approval on the receipt by Union of a written commitment from TransCanada (after it receives NEB approval) to proceed with the construction of King's North in accordance with the proposed schedule. Within ten days of its receipt by Union, the company shall provide the Board with a copy of TransCanada's written commitment to proceed, and the Board will determine at that time whether further action is required.

137 Union has indicated that it intends to expend funds on development work in relation to the pipeline in advance of the NEB's decision on King's North. The Board cautions Union that it will be at risk for recovery of these costs should the pipeline not proceed.

138 The Conditions of Approval for this application are attached as Appendix E of this decision.

4. Enbridge GTA Project (EB-2012-0451)

4.1 Need and Alternatives

139 Enbridge's GTA Project involves the construction of two segments of pipeline and associated facilities in and around the Greater Toronto Area. Segment A would be 27 km of NPS 42 pipeline in and around the Town of Milton, the City of Mississauga and the City of Toronto. Closely related to this is the Parkway Gate Station which will connect Enbridge to Union's Parkway West Station. Segment B would be a 23 km NPS 36 pipeline in and around in the City of Vaughan, the City of Markham, the City of Toronto and the Town of Richmond Hill. Enbridge is also seeking approval of its proposed rate methodology for Rate 332 for transportation services along Segment A.

Segment A/Parkway Gate Station

140 Segment A and the Parkway Gate Station would connect Enbridge to TransCanada and provide gas delivery to Enbridge's Albion Road Station. Segment A has a planned capacity of 2,000 TJ/day. Enbridge maintained that Segment A is needed primarily for distribution purposes, although it has additional transportation benefits and is related to Union's Brantford-Kirkwall/Parkway D Project and TransCanada's King's North project. Enbridge plans to use 40% of the capacity (800 TJ/day) on Segment A to serve in-franchise distribution customers while the remaining 60% (1,200 TJ/day) would be used for transportation purposes, serving ex-franchise customers.

141 Enbridge identified the following distribution benefits:

* increased supply diversity through access to gas supplies from the U.S. Northeast
* greater system capacity to meet load growth
* gas supply cost savings particularly for peak and seasonal supplies
* improved reliability of upstream arrangements by replacing less secure (short term firm and interruptible) long haul transportation from Western Canada with more secure short haul firm transportation from emerging U.S. Northeast and Dawn supply
* backup and entry point diversity for the single largest point of risk in the Enbridge franchise -- the Parkway Gate Station

142 Enbridge identified the following transportation benefits:

* access to gas from the U.S. Northeast using short-haul transmission
* greater access to the Dawn Hub

Segment B

143 Segment B is primarily designed to address load growth, safety and reliability issues. Enbridge forecasts that, by the winter of 2015/2016, the current infrastructure will be unable to supply the required volume of gas at the minimum required inlet pressure at Enbridge's Station B. Station B is the most remote point on the Extra High Pressure (XHP) system from the entry point of gas to the Enbridge GTA franchise area. Without the GTA Project, the inlet pressure at Station B is forecast to drop below the minimum system pressure. With the GTA Project, there will be additional capacity to serve Station B.

144 Enbridge first identified Station B inlet pressure as a concern in 2002. Enbridge explained that it had deferred construction of the proposed Segment B pipeline on a number of occasions, dating back to 1993, and instead had either procured additional Storage Transportation Service or Firm Transportation capacity. Enbridge noted that its ability to manage the operational risks has become constrained because customer growth has consumed the available capacity in the XHP distribution system.

145 In addition, the NPS 26 line is the only XHP pipeline connecting the western and eastern parts of Enbridge's distribution system serving the GTA. The smaller NPS 26 connecting pipeline is a bottleneck between the NPS 36 Parkway North line and the NPS 36 Don Valley line. The proposed Segment B would eliminate this east-west bottleneck and allow gas to be available from more diverse supply points and aid in daily load balancing.

146 Enbridge also noted that Segment B will address operating parameters recently implemented by the Technical Standards and Safety Authority ("TSSA") for pipelines operating at greater than 30% of Specified Minimum Yield Strength ("SMYS") in densely populated or high consequence areas. In order to mitigate the risk of a catastrophic event, Segment B would have an operating pressure below 30% SMYS whereas both the Don Valley and the NPS 26 line operate at greater than 30% SMYS. Enbridge indicated that these have been identified as high priority areas in the company's risk assessment process.

147 Enbridge explained that it had reviewed a variety of alternatives to the project: using existing pipeline infrastructure on the distribution system or external to Enbridge's system; curtailing existing firm customers; using liquefied natural gas; and contracting for more transportation services. Enbridge concluded that none of these were viable alternatives to the GTA Project. Enbridge also investigated compression alternatives within the distribution system to alleviate the potential of falling below minimum system pressure requirements. This alternative was rejected because it would involve adding compression at numerous locations which is problematic in an urban setting.

148 While most parties supported Enbridge's application, Environmental Defence, GEC and BOMA opposed the project on the basis that DSM was a viable alternative for all or part of the project. Both Environmental Defence and GEC coordinated to sponsor expert evidence on DSM.

149 Mr. Ian Jarvis, Ms. Wen Jie Li and Ms. Gillian Henderson from Enerlife Consulting provided expert evidence on behalf of Environmental Defence. Their evidence examined the potential role increased DSM efforts could play in offsetting load growth in the GTA area. Enerlife Consulting concluded 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.

150 Mr. Chris Neme and Mr. Jim Grevatt from Energy Futures Group and Mr. Paul Chernick from Resource Insight, Inc. provided separate, but related pieces of expert evidence on behalf of GEC. Energy Futures Group provided a companion piece of evidence to that of Enerlife Consulting. Energy Futures Group critiqued Enbridge's assessment of DSM as an alternative and provided an assessment of the potential incremental efficiency savings achievable in the GTA Project area based on the experience of leading jurisdictions. Energy Futures Group concluded that examples from other jurisdictions clearly demonstrate that Enbridge could be capturing much greater savings through aggressive energy efficiency than it has been capturing to date. Mr. Chernick examined the extent to which expanded DSM efforts could defer or avoid some or all of EGD's proposed GTA Project, with a focus on Segment B. Mr. Chernick concluded that Segment B appears to be avoidable through load reductions from a combination of accelerated DSM, expansion of interruptible or curtailment rates for industrial, commercial and apartment loads, and arrangements to reduce the load of the Portlands Energy Centre ("Portlands") (a large combined-cycle power plant served from Station B) on winter design-peak days.

Board Findings

151 The Board finds that the evidence supports the need for the GTA Project and that no superior alternative has been identified.

152 COC opposed the GTA Project as a whole for the same reasons it opposed the Union projects. The Board has already explained earlier in this decision in respect of the Union projects why it does not agree with COC's analysis, and the Board adopts the same reasoning in relation to COC's objections to the Enbridge project. The Board does not consider COC's arguments to be a valid basis to deny the application.

Segment A/Parkway Gate Station

153 Most parties supported Segment A and the Parkway Gate Station, largely for the same reasons they supported Union's Brantford-Kirkwall/Parkway D Project. Enbridge has been guided by the Board's direction in the Union EB-2011-0210 decision. In that proceeding, the Board was concerned with the potential for overbuilding or duplicative infrastructure which would result in adverse consequences to ratepayers. As a result, the Board directed Union Gas, Enbridge and TransCanada to co-operate on building natural gas infrastructure. The Board finds that Enbridge's Segment A, as well as Union's project, are responsive to the Board's direction. Segment A and the Parkway Gate Station alleviate a key transmission bottleneck, enable switching from long haul to short haul transportation services, and provide efficiency and optimization benefits through shared transportation and distribution use.

154 BOMA, GEC and Environmental Defence objected to Segment A and the Parkway Gate Station to varying degrees, largely for the same reasons BOMA and GEC objected to the Union Brantford-Kirkwall/Parkway D Project. The Board has previously addressed these arguments and has explained why it does not agree with the analysis. The Board adopts the same reasoning as it relates to Segment A and the Parkway Gate Station. As with the Brantford-Kirkwall/Parkway D Project, the Board finds that there is no credible evidence that DSM is a viable alternative to Segment A and the Parkway Gate Station.

Segment B

155 Most parties supported Segment B as the appropriate way to address customer growth and system reliability and safety concerns. However, a few parties raised objections and concerns with respect to whether the project is needed at this time and whether there were suitable alternatives. The Board will deal with each issue separately and then set out its expectations regarding future planning.

Segment B -- Need

156 Two issues were raised with respect to the need for the project:

- the risk assessment process
- the urgency of the requirement

157 Environmental Defence submitted that demand growth and gas supply alternatives were the primary drivers for Enbridge's proposal and that reliability concerns were a secondary consideration in the planning process. GEC questioned the rationale supporting pressure as a driver for Segment B, arguing that pressure was not a significant issue in the near or ***long term*** as many other lines on Enbridge's system currently operate above 30% SMYS. SEC also noted that a significant number of Enbridge's pipelines operate at or above 30% SMYS. Although supportive of the overall project, SEC submitted that Enbridge's risk assessment was inadequate and argued that the company should have developed or conducted an analysis of its distribution system to determine if and when facilities are needed to address pressure issues.

158 The Board finds that there was limited evidence that Enbridge undertakes a systematic and transparent risk assessment process for pipeline replacement. Other pipelines on the company's system are over 40 years old and operate at or above 30% SMYS, and Enbridge's prioritization process for determining pipeline replacement is not entirely clear. However, the Board finds that there are reliability issues associated with the NPS 26 and Don Valley Line which need to be addressed. These issues arise from load growth and recent TSSA code changes. Recent experience on the Don Valley Line confirms the existence of a significant physical risk. For any future pipeline replacement or reinforcement proposals, the Board expects to see a more transparent and systematic risk assessment and project prioritization.

159 While not opposing the project, some parties suggested that Segment B was the least urgent portion of the GTA Project, particularly the north-south Don Valley line, and that it could perhaps be done in stages or the construction start date deferred. The Board finds that Enbridge's evidence is adequate to approve the project now, and that there is no compelling reason to defer the building of Segment B or to stage the construction. The Board accepts Enbridge's evidence that there are cost efficiencies in proceeding with Segment B concurrently with Segment A.

Segment B -- Alternatives

160 Environmental Defence submitted that Enbridge had not established that the GTA Project was the preferred alternative compared to a combination of DSM and increased interruptible service. BOMA provided similar submissions with respect to Enbridge's lack of evaluating DSM as an alternative during its planning. GEC submitted that DSM as an alternative was not properly considered and that Enbridge did not fully evaluate the least cost planning option of increased conservation and/or rate design options.

161 Rate design options would include interruptible and/or curtailment rates for specific customers. For example, it was suggested that if Portlands were switched to an interruptible service, then the reliability issue would be largely addressed, at least in the short term. Portlands did not participate in the hearing, so it is speculation as to whether it would agree to such an arrangement. However, it is significant that Enbridge did not explore this option or other rate options with key customers. Enbridge explained that it plans its system to meet peak needs and assumes that interruptible loads are on.

162 The second alternative would be DSM programs. As noted above, both GEC and Environmental Defence provided expert evidence which examined the potential for increased natural gas savings in the GTA to offset or defer Enbridge's proposed GTA Project. Both GEC and Environmental Defence's experts concluded that some or all of Enbridge's GTA Project could be avoided or deferred.

163 GEC submitted that the Board needs to promote energy conservation and that DSM has proven to be a viable alternative to capital investments with a 4:1 benefit to cost ratio. Further, GEC submitted that concentrated DSM in higher influence areas could address Enbridge's peak issues on Segment B. The added benefit of this option would be greenhouse gas reduction, in accordance with government policy.

164 Environmental Defence submitted that DSM was a superior alternative to the project. In Environmental Defence's view, load growth and the reliability concern can be adequately addressed using DSM and interruptible rate options. Environmental Defence argued that such an approach would be less risky for ratepayers and would be consistent with government policy.

165 Many parties submitted that although DSM provides benefits, it was not a viable or reasonable alternative to Segment B. Board staff submitted that increased DSM activity is not a full or partial alternative at this time. In Board staff's view Enbridge's current approaches to DSM and system planning are not directly comparable because system planning is based on peak demand which is not the basis for DSM program planning. SEC submitted that it is not practical to require Enbridge to design and develop new DSM programs to meet an in-service date of winter 2015/2016. However, SEC also noted that Enbridge waited and addressed the pressure issue poorly, eliminating any possibility for targeted or increased DSM as an option.

166 Enbridge responded that it is fully committed to DSM but that DSM cannot be seen as an appropriate alternative to any portion of the GTA Project. Enbridge noted that the DSM framework is specifically intended to consider annual consumption savings.

167 Enbridge submitted that the capacity required to reduce the pressure in the Don Valley Line (165 TJ/day) is more than an order of magnitude larger than what Enbridge could achieve through its DSM efforts.

168 Based on the evidence of GEC and Environmental Defence, the Board accepts that targeted DSM programs and/or rate design options might in some circumstances mitigate the need for Segment B. However, there are significant uncertainties:

* It is uncertain whether DSM or rate design would fully offset the need for the pipeline. For example, Portlands is a firm service customer and presumably selected that option, including paying a substantial contribution in aid of construction, understanding its options. In addition, the intervenor evidence identified the use of 80 buildings for targeted DSM, but Enbridge's evidence is that there are only 42 such buildings in the relevant area.
* Considerable time and resources would be required to substantially re-structure Enbridge's current DSM program. The evidence suggests that the DSM budget would need to triple in size and the nature of the programs would change substantially.

* The impact of targeted DSM programs on Enbridge's peak demand is uncertain as Enbridge does not currently have the necessary analytical tools or information. The current DSM framework is intended to achieve annual consumption savings.
* The cost of the DSM programs is uncertain. It would be important to understand the costs and rate impacts as part of the analysis of the alternatives.

169 These uncertainties are significant because of the timing for Enbridge's requirement and the lack of documented success of this approach in another similar situation involving a gas utility. The Board accepts the company's evidence related to the timing in which the reliability and load growth issues must be addressed, given the physical system risks involved, and concludes that DSM and/or rate design options are not a sufficiently viable alternative in these circumstances to warrant denial of the project.

170 GEC and Environmental Defence also argued that the project should be rejected on the basis that Enbridge's planning approach was inadequate. The Board does not agree. Enbridge claimed to have considered DSM alternatives, but the consideration was cursory at best. The evidence is clear that no staff with DSM expertise attended the relevant meetings. Enbridge acknowledged that it had not conducted integrated resource planning[9] and argued that it could not have been expected to do so. The company conducted its planning, and the assessment of alternatives, within the context of the current regulatory framework and the current framework for DSM. The Board finds that this approach was reasonable in the circumstances.

Future Planning

171 Environmental Defence urged the Board to send a signal to the companies that new supply-side investments will not be approved unless all lower cost DSM and/or interruptible service options have been explored and documented. Other parties agreed and argued that both Enbridge and Union should be required to do a better job at properly incorporating DSM into system planning, with some parties suggesting that both companies should be required to conduct integrated resource planning.

172 Enbridge responded that if the Board decides to consider integrated resource planning within the DSM framework, or more broadly in a generic hearing, Enbridge would be willing to take a leadership role. Enbridge was supportive of a generic hearing regarding the role of geographically targeted DSM programs under an integrated resource planning framework, including addressing some of the suggestions from Environmental Defence, GEC and BOMA.

173 In light of the evidence presented, the Board concludes that further examination of integrated resource planning for gas utilities is warranted. The evidence in this proceeding demonstrates that the following issues should be examined:

* The potential for targeted DSM and alternative rate designs to reduce peak demand
* The role of interruptible loads in system planning
* Risk assessment in system planning, including project prioritization and option comparison
* Shareholder incentives

174 There will undoubtedly be other issues as well. The Board notes that this review is particularly timely given the recent provincial ***Long Term*** Energy Plan. Further information on how the Board will examine gas integrated resource planning will be released in due course.

175 Pending that review, the Board expects applicants to provide a more rigorous examination of demand side alternatives, including rate options, in all gas leave to construct applications.

4.2 Project Costs, Economic Evaluation, Rate Impact (including Rate 332)

176 Enbridge estimated the cost of the GTA Project to be $686.5 million. Segment A is estimated to cost approximately $384 million, including the Parkway West Gate Station, while Segment B is estimated to cost approximately $302 million. Enbridge conducted economic feasibility calculations for the GTA Project in accordance with both E.B.O 188 and E.B.O. 134. Based on Enbridge's analysis, the PI of the GTA Project is 1.73 and the NPV is $667 million. Enbridge also conducted sensitivity analysis scenarios: 10% higher capital costs; zero transmission revenue from shippers on Segment A; 25% and 50% lower transportation cost savings. Under these scenarios, either individually or collectively, the GTA Project is still economically feasible in Enbridge's analysis. Because the economic feasibility results are positive, the company only performed a Stage 1 analysis. However, Enbridge maintained that the evidence shows that Stage 2 benefits would be substantial for consumers using natural gas as opposed to other fuels. Enbridge also noted that the reliability benefits of GTA Project were not monetized, and are not part of the economic feasibility calculations, but are of significant value.

177 Under Enbridge's analysis, total bill impacts are positive overall. Enbridge provided bill impacts for each rate class, calculated two ways: (1) the total impacts associated with all three applications (Enbridge's GTA Project and Union's Parkway West and Brantford-Kirkwall/Parkway D Projects) and the expected gas cost savings; and, (2) the bill impacts associated solely with the Settlement Agreement, which relates to increased gas costs. The first analysis indicates customer bill savings ranging from a reduction of 3.7% for residential customers to a reduction of 11.0% for industrial customers. The second analysis indicates customer bill increases ranging from an increase of 2.3% for residential customers to an increase of 3.4% for industrial customers.

178 Enbridge also requested Board approval of the proposed rate methodology for Parkway to Albion transportation service on Segment A under Rate 332. Enbridge proposed that 60% of the fully allocated revenue requirement for Segment A be allocated to transportation service customers. Enbridge has also proposed that the allocated costs be recovered through a monthly charge, but the company indicated that the actual rate design for Rate 332 should be reviewed by the Board in the company's customized incentive rate application which is currently before the Board.[10]

179 Parties provided a range of submissions regarding the economics of the GTA Project. However, there was general support for Enbridge's proposition that the GTA Project will allow the company to switch to short haul transportation for seasonal or peaking needs from the more expensive firm long haul service which it is currently using.

180 Parties raised two concerns with respect to rate impacts: the estimated gas cost savings and the allocation of costs on Segment A, particularly in the event there are no transportation customers. With respect to gas costs savings, parties raised many of the same issues as were raised in the context of Union's Brantford-Kirkwall/Parkway D Project.

181 With respect to the allocation of Segment A costs, Enbridge's proposal is that if there are no transportation service customers on Segment A, then the full revenue requirement would be recovered from in-franchise customers. Board staff submitted that it is unreasonable for distribution customers to bear the risk and cost consequences in the event that transmission service revenue on Segment A does not occur or is delayed. Board staff submitted that the risk should reside with the parties standing to benefit from the availability of incremental capacity stemming from upsizing Segment A from NPS 36 to NPS 42, such as transmission customers or Enbridge shareholders. CME, CCC, BOMA and Energy Probe took similar positions. CME suggested that a condition of approval should be added so that Enbridge cannot begin construction of Segment A until it provides an undertaking to the Board that it will not seek to recover from its distribution customers any more than 40% of the revenue requirement for Segment A.

182 Some parties argued that additional costs should be allocated to transportation customers in any event, namely the incremental costs of increasing the pipe size and changing the starting point. Energy Probe submitted that it is not appropriate for ratepayers to have any cost responsibility for additional capacity or operating capital related to Enbridge's change from an NPS 36 to NPS 42 pipeline as it is unnecessary to serve its in-franchise distribution needs. FRPO submitted that the incremental cost of moving the starting point of Segment A from Bram West to Parkway only benefits transportation services and therefore the incremental cost should be borne by those customers.

183 Enbridge noted that the original application was for a distribution-only NPS 36 pipeline and that its revised approach added the transportation component in response to the Board's direction in Union's EB-2011-0210 proceeding where the Board encouraged cooperation amongst Union, Enbridge, and TransCanada with regard to natural gas infrastructure expansion. Enbridge further noted that the updated application and approach to Segment A results in distribution ratepayers bearing 40% of the revenue requirement on $350 million rather than 100% of the revenue requirement for a project that would cost only $55 million less. Enbridge submitted that the results of its open season for Segment A demonstrated enough interest to warrant an NPS 42 pipeline.

184 Enbridge argued that it would be inappropriate for shareholders to bear the risks associated with 60% of the revenue requirement of Segment A. Enbridge maintained that if the Board were to accept the position advanced by Board staff regarding the allocation of responsibility for the revenue requirement of Segment A, the company could not proceed with the GTA Project on that basis. Enbridge submitted that the GTA Project is not primarily for transportation purposes, but rather that it is primarily for distribution purposes.

Board Findings

185 The Board accepts the cost estimate for the GTA Project as reasonable and finds that the economic analysis, along with the qualitative factors related to supply diversity and reliability, supports a conclusion that the project is in the public interest.

186 Some parties challenged the estimates of gas cost savings. The Board has already addressed this issue in its decision on Union's Brantford-Kirkwall/Parkway D Project. The Board does note however, that the evidence supporting gas cost savings is stronger for this project than for the Union project. Enbridge is currently relying on firm service for seasonal requirements, thereby incurring significant unabsorbed demand charges. The completion of Segment A will facilitate a shift to alternative sources of seasonal services, and the evidence demonstrates these alternatives will be less expensive.

187 Parties supported the proposed 60/40 transportation/distribution allocation of the Segment A revenue requirement. However, some parties argued that in addition to the 60/40 split, all of the incremental costs associated with changing Segment A to a joint distribution/transportation project should also be allocated to transportation customers. The Board does not agree. Segment A is an integrated distribution and transportation pipeline and the cost allocation method appropriately allocates costs on the basis of total costs and the proportion of total capacity for each use.

188 Some parties also disputed who should bear the costs of unused transportation capacity on Segment A. This situation would arise if Segment A were completed before Union's Brantford-Kirkwall/Parkway D Project and/or TransCanada's King's North project. Enbridge proposed that the costs be recovered from distribution customers. Some parties argued that the Board's approval should be conditioned on the NEB's approval of King's North. That proposal, which the Board will not adopt, is discussed later under Conditions of Approval. Other parties argued that Enbridge's shareholders should bear the risk of unused transportation capacity. The Board does not agree that shareholders should be at risk for 60% of the revenue requirement for Segment A. The project is a combined distribution and transportation project. The project is responsive to the Board's direction in Union EB-2011-0210, *2012 LNONOEB 362* that the various companies cooperate on infrastructure planning. The Board accepts that this type of coordination may result in some timing differences amongst the projects. The benefits of a combined approach are significant in terms of lowering total cost, avoiding duplicate infrastructure and reducing environmental impact.

189 However, the Board also agrees with parties that if there is no transportation revenue, distribution customers should not automatically bear the costs associated with the incremental capacity added to serve transportation customers. The evidence is that the cost difference between the NPS 36 pipeline (which would be required for distribution needs only) and the NPS 42 pipeline (which accommodates both distribution and transportation needs) is $55 million. Once Segment A is in service, if there are no transportation customers, then Enbridge will be required to record the revenue requirement impact of the $55 million in a deferral account for eventual recovery from transportation customers on Segment A.

190 There are also incremental costs associated with changing the starting point from Bram West to Parkway. However, under a distribution-only project, with Bram West as the starting point, there would also have been additional TransCanada charges. The charges are avoided in the combined distribution and transportation project. For this reason, the Board will not segregate the incremental starting point costs.

191 The Board will also approve the proposed methodology for transportation service on Segment A under Rate 332. The Board finds that the proposed 60/40 allocation of the revenue requirement for Segment A to transmission and distribution customers respectively is consistent with established cost allocation principles in that 60% of the capacity is for transportation customers and 40% is for distribution customers. The Board notes however that the detailed rate design will be examined through a separate proceeding, at which time parties will have an opportunity to review this issue in greater detail.

192 APPrO opposed the rate impact on unbundled distribution customers and argued that the costs of the GTA Project should be borne mostly by bundled and transportation customers. APPrO indicated that it intended to address this concern in an upcoming rate proceeding, likely Enbridge's IRM application. APPrO's argument is similar to the submission Kitchener made on Union's Parkway West Project. Like Kitchener, APPrO raises considerations which require an examination of cost allocation principles which is beyond the scope of this proceeding. Cost allocation issues are generally reviewed in cost of service rebasing hearings, and APPrO has indicated that it intends to raise the issue in a future rates proceeding. The Board need not make a determination on this issue at this time.

4.3 Environmental, Technical and Safety Issues

193 Dillon Consulting Inc. ("Dillon") prepared an environmental report for Enbridge in 2012 and recommended the route and location for the GTA Project through the process outlined in the Board's *Environmental Guidelines*. Dillon subsequently prepared two amendments to the environmental report, one in February 2013 and the second in July 2013 in response to ongoing consultations. According to the report, the locations of Segment A and Segment B are the environmentally preferred routes. A mitigation plan has been developed to minimize any potential impacts. There were no issues raised by parties with respect to the GTA Project environmental report.

194 Enbridge stated that the design, installation and testing of the pipeline and station facilities would meet or exceed the most stringent standards according to CSA Z662-11 which is the Canadian Standards Association's Oil & Gas Pipeline System standard (2011 edition). There were no issues raised by parties with respect to technical and safety requirements.

Board Findings

195 The Board accepts Enbridge's evidence regarding the environmental assessment of the GTA Project, and finds that the proposed mitigation and monitoring activities are acceptable and address the environmental concerns. Enbridge has committed to implementing all the recommendations of the Environmental Report. The Conditions of Approval reflect Enbridge's commitments.

196 The Board is also satisfied that the evidence establishes that the pipeline design and specifications are acceptable based on current standards.

4.4 Landowner Matters

197 Enbridge submitted that there are no outstanding issues with respect to land matters related to the GTA Project. Enbridge included a proposed form of agreement as part of its application. Enbridge noted that it has offered, or will offer, the form of agreement to each of the landowners affected by the GTA Project. Enbridge noted that it will complete agreements with landowners, and obtain permits, following approval of the project by the Board.

198 Metrolinx and York did not object to the proposed pipeline route, but submitted that they would like to continue to be included in discussions about the project once the final detailed engineering plans are complete.

199 Metrolinx noted that Enbridge still needs to obtain the necessary permits and/or enter into the crossing agreements required by Metrolinx. Enbridge responded by confirming that it will continue to work with Metrolinx through the detailed design of the GTA Project, provide detailed design drawings, obtain permits and enter into crossing agreements necessary to carry out the work. Enbridge also noted that it will, to the extent practicable, avoid impacting existing and planned GO Transit and Metrolinx facilities.

200 York submitted that it remains concerned about temporary and permanent impacts of the construction and operation of the proposed pipeline on existing and planned regional facilities. York noted that Enbridge will still be required to obtain all the necessary permits and/or enter into agreements as required by York. Enbridge confirmed that detailed engineering or construction plans will include proposed construction and staging requirements for the pipeline, and the plans will be provided to York for its review and comment. Enbridge also confirmed that it will continue to work with York through the detailed design of the GTA Project, obtain permits and enter into agreements necessary to carry out the work and avoid impacting existing and planned York facilities where practicable.

201 8081 Woodbine Investment requested that a condition be included in the Board's Conditions of Approval indicating that leave to construct does not authorize any expropriation in respect of Part 1 on Plan 65R-32626, owned by 8081 Woodbine Investment land. Enbridge confirmed it does not require land rights in respect of Part 1 on Plan 65R-32626 and submitted that the proposed condition is not warranted and that it is premature for the Board to make such a ruling. Enbridge submitted that any issue with expropriation is more properly dealt with by the panel constituted to consider any such application.

202 Enbridge noted that it and Markham Gateway had entered into Minutes of Settlement in respect of the location of the GTA Project within the Markham Gateway lands. Enbridge expressed its intention to fulfill its obligations as set out in the Minutes of Settlement.

Board Findings

203 Enbridge has successfully resolved most landowner issues. Several landowners and adjacent landowners have requested that Enbridge continue to work with them to keep them informed of progress and ensure there are no land conflicts. The Board notes Enbridge's commitments to York Region, Metrolinx, Markham Gateway and Contango.

204 With respect to the condition of approval proposed by 8081 Woodbine Investment, the Board agrees with Enbridge that it is inappropriate for the Board to make any decisions on possible expropriation at this time. Issues related to expropriation are beyond the scope of this proceeding.

205 The Board approves the form of easement which has been filed by Enbridge.

4.5 Aboriginal Consultation

206 Enbridge followed the consultation guidelines set out in the Board's *Environmental Guidelines*. Two First Nations intervened in the proceeding: the Mississaugas of the New Credit First Nation ("MNCFN") and the Six

Nations. Both were granted costs eligibility. Six Nations withdrew from the proceeding on April 24, 2013. The MNCFN filed written submissions.

207 The MNCFN suggested that the Crown's duty to consult with respect to potential impacts to existing or asserted Aboriginal or treaty rights has not been satisfied. The MNCFN requested that the Board include a variety of conditions to any approval, including a request that the project be delayed until Enbridge has provided the appropriate financial resources to retain expertise to review the project. MNCFN requested that it be included in further environmental assessments conducted on traditional territory.

208 Enbridge reiterated its commitment to continue to work with the MNCFN throughout the remainder of the planning, design and construction for the GTA Project, a commitment outlined in the environmental report. Enbridge noted that as a result of the findings in the archaeological assessments the location of the proposed pipeline was altered to reduce and mitigate potential impacts and a Stage 2 archaeological assessment was scheduled for completion in 2013. Enbridge noted that in April 2013, Dillon wrote to the First Nations and Métis organizations regarding the results of the Stage 2 assessment that had been completed on a 7 km section of Segment B, which indicated that no archaeological remains were found in this section. Enbridge further noted that there has been additional correspondence with First Nations and Métis organizations regarding the completion of Stage 2 and Stage 3 archeological assessment work. Enbridge committed to continuing to work with all First Nations, including the MNCFN, and Métis throughout the remainder of the archeological assessment, and the design and construction of the GTA Project.

209 Board staff noted that the MNCFN had notice of this proceeding since March, 2013 and that it appears that Enbridge's pre-filed evidence addressed many of the MNCFN concerns. Board staff noted that to the extent that the MNCFN was not satisfied with Enbridge's proposal, or if it had further questions, the interrogatory process would have been an appropriate forum to obtain additional information. Board staff did not support the conditions requested by the MNCFN.

Board Findings

210 The MNCFN was granted intervenor status and was deemed eligible for a cost award. The MNCFN did not file any interrogatories, and did not participate in the Issues Day, the settlement conference, or the oral hearing but did participate in final argument. It is unfortunate that the MNCFN did not take advantage of the opportunity to explore Enbridge's evidence in detail through the hearing process. For example, Enbridge's archaeological assessment could have been subjected to questioning through the interrogatory process and the oral hearing. That is one of the key purposes of having a hearing. The Board provided the MNCFN with eligibility for an award of costs, so funding for counsel, consultants and experts (if required) was available.

211 With respect to the MNCFN's submissions regarding the duty to consult, the Board offers the following comments. To the extent that the duty to consult issues identified fall within the Board's jurisdiction, it is the Board's responsibility to ensure appropriate consultation has taken place. MNCFN does not suggest that the Board itself should be engaged in one on one consultation. The Supreme Court's decision in *Rio Tinto Alcan Inc. v. Carrier Sekani Tribal Council*[11] also suggests that this will not normally be the role of a tribunal.

212 The MNCFN indicated that it is in the process of developing a ***long-term*** relationship agreement with Enbridge Inc. but that an agreement has not yet been finalized. The Board takes this as a positive indication that discussions are ongoing between the parties at a variety of levels, including with respect to this particular project, and therefore no formal findings are required at this time with respect to the quality of the consultations that have occurred with respect to this project. In addition, the MNCFN proposed a number of conditions designed to address its primary concerns. The MNCFN's proposed conditions were as follows:

* For each work site, Enbridge provide MNCFN with the following information: (i) exact location and size of site; (ii) plans to protect the environment and sensitive watershed; and (iii) the

contamination characteristics, dewatering details, and water treatment and discharge plans for the site.

* Enbridge Gas permit third party contractors ("Monitors") selected by the MNCFN to actively participate in Enbridge's environmental and archaeological assessment and monitoring work at any Work Site that has high archaeological potential or has significant environmental concerns, as determined by MNCFN.
* Enbridge Gas provide financial resources to the MNCFN to hire and administer the Monitors and to hire consultants to review all of the permits and approvals that Enbridge has made with respect to the initial construction and ongoing operations and maintenance activities, to the extent necessary to protect the MNCFN's rights, title and interests.
* Enbridge Gas ensure that adequate insurance and/or funds are available for any cleanup, compensation and restoration in the event of accidents and malfunctions on the MNCFN's traditional territory resulting from the Project and any operations and maintenance activities in the future.

213 The Board finds that the first condition is reasonable and that condition will be adopted as presented. With respect to the other three conditions, the Board finds that the conditions should be applied in conjunction with a reasonability standard and therefore the Board has modified them accordingly. In addition, the Board's Conditions of Approval only govern the construction phase, not ongoing operations and maintenance. Enbridge's ongoing operations are governed using other mechanisms, including rate regulation and various technical requirements established by standards-setting authorities. The Board will modify each of the conditions accordingly:

* Enbridge Gas will permit Monitors selected by the MNCFN to actively participate in Enbridge's environmental and archaeological assessment and monitoring work at any Work Site that has high archaeological potential or has significant environmental concerns, as determined jointly by the MNCFN and Enbridge, both parties acting reasonably.
* Enbridge Gas will provide reasonable financial resources to the MNCFN to hire and administer the Monitors and to hire consultants to review the construction permits and approvals required by Enbridge, to the extent necessary to protect the MNCFN's rights, title and interests.
* Enbridge Gas will ensure that it has adequate insurance and/or funds available for any cleanup, compensation and restoration in the event of accidents and malfunctions on the MNCFN's traditional territory resulting from the project.

214 With the application of those conditions, the Board is of the view that it is appropriate for the Board to issue its final decision with respect to this application.

4.6 Conditions of Approval

215 Enbridge accepted the standard conditions of approval for section 90 and section 91 applications as proposed by Board staff with a termination date of February 28, 2015.

216 For Segment A, the main concern raised by parties was how the in-service date should correspond to the proposed TransCanada King's North project. It was the general position of parties that Segment A should be in some way tied to the approval and construction schedule of the TransCanada project.

Board Findings

217 The Board notes that Enbridge has accepted all standard conditions with a revised termination date of February 28, 2015, which is acceptable to the Board.

218 The Board has considered the interrelationships amongst the projects and how appropriate conditions may be used to ensure a rational construction sequence with respect to the approved facilities. The Board has conditioned the Brantford-Kirkwall pipeline on approval of TransCanada's King's North project. Many parties argued that Segment A should be similarly conditioned. Energy Probe proposed a related condition requiring that Enbridge demonstrate it has entered into ***long-term*** contracts for capacity on Segment A. The Board will not adopt these conditions. Although Segment A is related to the Union and TransCanada pipeline projects, it also has a distribution purpose which is distinct. The Board will therefore not condition Segment A on the NEB's approval of the King's North project or the completion of ***long-term*** contracts. Ideally, all of the projects (Union's, Enbridge's and TransCanada's) would be in-service at the same time. However, the Board accepts that there is some risk of timing differences. Elsewhere in this decision the Board has addressed how the risk of underutilized transmission capacity on Segment A will be treated.

219 Various parties proposed other conditions of approval, which have been addressed elsewhere in this decision. The Conditions of Approval for this project are attached at Appendix G.

5. THE BOARD ORDERS THAT:

   1. Union Gas Limited is granted leave, pursuant to sections 90(1) and 91 of the Act, to construct the Parkway West project, consisting of the installation of a compressor and the construction of 740 meters of natural gas pipeline and associated facilities in the Town of Milton, all subject to the conditions of approval set out in Appendix C.
   2. Union Gas Limited is granted approval, pursuant to section 36 of the Act, for the recovery of up to $219 million of capital costs for the Parkway West Project, beginning from the date that the as-constructed facilities are placed in service. The Board further approves the creation of a Parkway West variance account to track any variances from the $219 million cost estimate.
   3. Union Gas Limited shall file a Draft Accounting Order for the Parkway West Project with the Board within **10 days** of the date of this Decision and Order. The Draft Accounting Order shall include the purpose of the account, an account description, the account number and accounting entries for recording any variances.
   4. Union Gas Limited is granted leave, pursuant to sections 90(1) and 91 of the Act, to construct the Brantford-Kirkwall/Parkway D Project; consisting of 13.9 km of NPS 48 pipeline and associated facilities between the City of Cambridge and the City of Hamilton and a new compressor at the Parkway West site, all subject to the conditions of approval set forth in Appendix E.
   5. Union Gas Limited is granted approval, pursuant to section 36 of the Act, for the recovery of up to $204 million of capital costs for the Brantford-Kirkwall/ Parkway D Project, beginning from the date that the as-constructed facilities are placed in service. The Board further approves the creation of a Brantford-Kirkwall/Parkway D variance account to track any variances from the $204 million cost estimate.
   6. Union Gas Limited shall file a Draft Accounting Order for the Brantford-Kirkwall/Parkway D Project with the Board within **10 days** of the date of this Decision and Order. The Draft Accounting Order shall include the purpose of the account, an account description, the account number and accounting entries for recording any variances.
   7. Enbridge Gas Distribution Inc. is granted leave, pursuant to section 90(1) and 91 of the Act, to construct the GTA Project; consisting of the construction of two segments of natural gas pipeline, and associated facilities, in and around the City of Toronto, more particularly described as: Segment A (approximately 27 km long and located in the Town of Milton, the City of Mississauga and the City of Toronto), the Parkway West Gate Station and associated facilities, and Segment B (approximately 23 km long and located in the City of Vaughan, the City of Markham, the City of

Toronto and the Town of Richmond Hill), all subject to the conditions of approval set out in Appendix G.

8. Enbridge will create a deferral account to track the revenue requirement impact of $55 million in incremental capital spending associated with the transmission component of the GTA Project. Enbridge Gas Distribution Inc. shall file a Draft Accounting Order with the Board within **10 days** of the date of this Decision and Order. The Draft Accounting Order shall include the purpose the account, an account description, the revenue requirement impact calculation methodology for recording costs, the account number and accounting entries.
9. Intervenors shall file with the Board and forward to Union Gas Limited and/or Enbridge Gas Distribution Inc. their respective detailed and project specific cost claims within **7 days** from the date of this Decision and Order.
10. Union Gas Limited and Enbridge Gas Distribution Inc. shall file with the Board and forward to intervenors any objections to the claimed costs within **14 days** from the date of this Decision and Order.
11. Intervenors shall file with the Board and forward to Union Gas Limited and/or Enbridge Gas Distribution Inc. any responses to any objections for cost claims within **21 days** of the date of this Decision and Order.
12. Union Gas Limited and Enbridge Gas Distribution Inc. shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

220 All filings with the Board must quote the file number EB-2012-0451/EB-2012-0433/EB-2013-0074, and be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/,and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Parties should use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca.

221 If the web portal is not available, parties may e-mail their documents to the attention of the Board Secretary at BoardSec@ontarioenergyboard.ca. All other filings not filed via the Board's web portal should be filed in accordance with the Board's *Practice Directions on Cost Awards*.

DATED at Toronto, January 30, 2014

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

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1 Shale is a low permeability rock, and gas found in it is produced by using horizontal drilling and hydraulic fracturing. Conventional gas supplies come from higher permeability rock. There are extensive shale supplies in the eastern U.S., western Canada and in other parts of North America.

2 EB-2013-0202, *2013 LNONOEB 11*

3 The Ontario Pipeline Coordinating Committee (OPCC) coordinates the Ontario government's review of natural gas facility projects in Ontario that require approval from the Board. Its goal is to minimize negative environmental impacts that could arise from these projects by reviewing environmental assessments and routing reports prepared by the applicants before they apply to the Board to have projects approved. The committee is made up of government

ministries and agencies that have a role in reviewing natural gas transmission and distribution facility projects and is chaired by a staff member from the Board.

4 EB-2005-0551, *2006 LNONOEB 64*

5 Transcript Vol. 7, p. 55-56.

6 EB-2012-0092,

7 RH-003-2011

8 EB-2008-0280, *2009 LNONOEB 113*

9 An integrated resource plan is a utility plan for meeting demand through a combination of supply-side and demand-side resources.

10 EB-2012-0459, *2014 LNONOEB 14*

11 *[2010] 2 S.C.R. 650*, para. 60.

TAB 4 - Report of the Ontario Energy Board, issued October 25, 2018, Framework for the Assessment of Distributor Gas Supply Plans, EB-2017-0129

Ontario Energy Board | Commission de l'énergie de l'Ontario

October 25 2018

Report of the Ontario Energy Board

Framework for the Assessment of Distributor Gas Supply Plans

EB-2017-0129

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Table of Contents

1. Introduction

The Ontario Energy Board (OEB) has developed a Framework for the Assessment of Distributor Gas Supply Plans (the Framework). The Framework sets out the OEB's approach for the assessment of the cost consequences of rate-regulated natural gas distributors' (distributors) gas supply plans. The Framework will ensure that there is transparency, accountability and measurability regarding the distributors' gas supply plans to assure they deliver value to consumers. This Report of the Ontario Energy Board (the Report) provides the Framework and rationale behind it. The Report is designed to provide both distributors and customers information about the necessary elements of a gas supply plan and the OEB's approach to the assessment.

Distributors that are rate-regulated by the OEB provide natural gas supply services for the vast majority of their customers. The distributors supply the gas commodity to system gas customers who have chosen to buy gas from the distributor rather than enter into a contract with a gas marketer or producer directly. As well, distributors provide transportation (in some cases) and load balancing services (including storage) to customers who purchase their gas supply directly. These services require the distributors to develop a plan for supply, transportation and storage to meet the forecasted customer demand.

Gas supply costs represent a significant component of the gas bill for all customers – approximately 45 per cent for the average residential customer, for instance. The proportion of the bill that consists of gas supply costs varies as the market price of natural gas changes. The decisions made concerning gas supply and the arrangement of associated transportation and storage can have significant multi-year impacts on natural gas customers' costs.

In keeping with its commitment to protect consumers and hold distributors to account, the OEB has identified three guiding principles that will be used in assessing gas supply plans: cost effectiveness, reliability (which includes security of supply) and support for public policy. The Framework outlines the information that the OEB requires to assess whether the gas supply plans appropriately balance the guiding principles and deliver value to customers. The responsibility for delivering reliable supply to customers in a prudent manner remains with the distributors. Distributors manage and execute their plans and adjust their activities to address changes to demand and supply conditions.

1.1. Consultation to Develop the Framework

On March 16, 2017, the OEB launched the initiative to update the regulatory approach to the gas supply planning process with the objective of injecting greater transparency, accountability and measurement to ensure that consumers are getting value for money. Through this initiative, the OEB determined that it would develop a framework designed to achieve these objectives, and to allow for a consistent approach to the assessment of rate-regulated distributors' gas supply plans. A Technical Working Group, having a balanced and broad representation of relevant interests, was established to provide advice on a number of topics related to the development of the Framework.

The OEB issued the *Draft Report of the Ontario Energy Board: Framework for the Assessment of Distributor Gas Supply Plans* (Draft Framework) on April 12, 2018 for stakeholder comment. The OEB received comments from nine stakeholders, including natural gas utilities, consumer groups representing residential, commercial and industrial natural gas users as well as environmental organizations.

Stakeholders were generally supportive of the Draft Framework and the OEB's initiative to provide guidance on its assessment of gas supply planning with the objective of increasing accountability, transparency and performance measurement. Some comments focused on the principles that would guide the OEB's assessment of the plans, including the inclusion of public policy as a guiding principle. Distributors suggested some changes to the principles, including seeking greater specificity in the set of principles. Stakeholders provided comments regarding the assessment criteria as well as how they should be applied. Some stakeholders questioned whether the length of time between plan reviews was too long to ensure oversight given the changing state of gas markets. A number of stakeholders commented on the assessment process, saying there was a need for increased stakeholder engagement and that the process should follow more of an adjudicative approach rather than the stakeholder model that ends with a report by OEB staff.

The OEB has considered all of the comments and made amendments to the Framework where appropriate. Additional clarity regarding the principles that will guide the OEB's review has been provided. In regard to comments on the plan review process, the information contained in the review and assessment of gas supply plans is intended to inform other related applications and provide a basis of understanding about the plans for the OEB when it is deciding on related applications. As stated earlier, the assessment of the gas supply plans will not result in a decision on the costs or cost recovery. That would be the subject of related applications. Changes have been made to the process for plan review to allow for additional stakeholder engagement, including questions and additional submissions.

1.2. Next Steps to Implementing the Framework

In order to implement the Framework, a distributor will submit to the OEB a comprehensive five-year gas supply plan for a detailed review once every five years. In addition, distributors will submit an annual gas supply update that focuses on the changes to the supply and demand conditions and includes a retrospective view of the plan's performance. The OEB has set out the process and approach it intends to take for the review of the five-year gas supply plan and the annual gas supply update. Through a robust review of the plan, including consideration of rate impacts and risks, the OEB will be able to rely on the plans in related applications filed by distributors.

This Report is organized into six sections including this introduction to the initiative.

Section two provides background on the current review of distributors' gas supply plans and the consultations that led to the development of the Framework.

Section three sets out the guiding principles and criteria that the OEB will rely on to assess the cost consequences of the distributor's gas supply plans.

Section four explains the process the OEB intends to follow for the review of distributors' gas supply plans.

Section five describes how the results of the OEB's review may be used in other related applications before the OEB.

Section six sets out the OEB's plan for evaluating the effectiveness of the Framework in meeting the objectives of transparency, accountability and improved performance measurement.

Finally, as part of implementing the Framework, the OEB has identified filing requirements for both the five-year gas supply plan and the annual gas supply update, which are attached as Appendix A to this Report.

2. Background

2.1. Gas Supply Plan Development

The goal of a distributor's gas supply plan is to develop a portfolio of gas supply, transportation and storage assets that provides customers with service that meets demand and is consistent with the province's public policy objectives.

Gas supply planning starts with a demand forecast. The distributor's projected customer requirements will differ between distributors and regions and is based on customer mix and location. Once the demand forecast is developed, distributors identify how they will provide sufficient supply to meet their demand requirements. Distributors will determine the mix of assets (i.e., transportation and storage) that will enable them to achieve this goal. Once the asset mix is developed, distributors will then determine an approach to procuring the commodity that efficiently utilizes the assets. This could entail various pricing tools such as longer term price commitments and shorter term or index pricing approaches.

2.2. Current Gas Supply Planning Review

Distributors currently provide gas supply information to the OEB at various times. The gas supply memoranda that distributors include in their annual rate application provides an overview of a distributor's planning activities. The overview describes the process that the distributor has adopted in developing its supply, transportation and storage strategies to meet its forecasted demand. The primary focus of the rate application is not the pass-through charges related to gas supply. This is done as part of the Quarterly Rate Adjustment Mechanism (QRAM) discussed below.

Through the consultations it has been identified that the memoranda do not provide critical data that would enable the OEB to assess how the plan compared to the distributor's forecast or the customer bill and rate impacts. The review of a distributor's application covers a wide range of topics and provides limited opportunity for the OEB to assess and connect the distributor's gas supply planning process with the cost information in the rate application. Under the Framework, it is expected that distributors' gas supply plans will expand on the information in the memoranda to meet the objectives set out here.

Distributors are reimbursed for supply and transportation on a cost pass-through basis through the QRAM. The QRAM process reflects the result of the distributor's implementation of gas supply planning activities and any near-term actions taken to respond to market conditions. It is intended to be a mechanistic approach to adjust rates based on: (a) variances between the previously set rate and the actual costs incurred;

and (b) the impact of updated future forecasted gas supply prices on the gas supply portfolio. As the QRAM process is mechanistic, it does not provide opportunity for a detailed assessment of the inputs and does not articulate a link between gas supply planning and the QRAM rates.

2.3. Developing the Framework – Prior Policy Initiatives

The winter of 2013/14 was much colder than forecasted, which caused the demand for, and price of, natural gas to increase significantly across a large portion of North America. The two large gas distributors in Ontario, Union Gas Limited and Enbridge Gas Distribution Inc., implemented their respective supply plans but in the end experienced supply costs that were far in excess of what was forecasted. This resulted in significant but different rate impacts in each of the distributor's subsequent applications under the QRAM. To better understand the factors that contributed to this price increase, its impact on customers and the reasons for the distributors' different approaches, the OEB undertook a number of initiatives to review what happened, the adequacy of the existing gas supply planning process and the OEB's regulatory oversight of it.

In December 2014, the OEB hosted a Natural Gas Market Review that included a discussion of pricing influencers in the winter of 2013/2014 and their impact on customers. The resulting OEB Staff Report to the Board on the 2014 Natural Gas Market Review recommended that the OEB initiate a proceeding to review its policy in relation to gas procurement and the assessment and approval of distributor gas supply plans.

Following the Natural Gas Market Review, the OEB initiated a stakeholder consultation on distributor gas supply planning (EB 2015-0238) to focus on gas supply and transportation planning strategies and the approach distributors take to developing their plans. The output of the consultation was an OEB Staff Report to the Ontario Energy Board. The Staff Report proposed a structure and content for future gas supply planning memoranda, and recommended that the OEB consider improvements to the current review process for gas supply planning. The recommendations were based on the three foundational objectives, identified through the consultations, of increased accountability, transparency and performance measurement.

1) *Increased Accountability - Gas distributors should apply for pre-approval of their Gas Supply Plan on a stand-alone basis (separate from other applications). The application should be submitted at the same time, in the same format (to ensure that they can be easily compared) and reviewed jointly by the same panel.*
2) *Increased Transparency - Gas distributors should submit a gas supply memorandum annually on a stand-alone basis. This new memorandum should be in a common format and submitted at the same time. The content should be consistent with the information already included in gas supply*

memoranda and include the side-by-side comparison document developed in this consultation.

3) *Performance Measurement – To increase the OEB's ability to measure the performance of the distributors' gas supply plans, the new memoranda should include a report card on the performance of the plan over the previous 3 years along with a forecast of the forward looking 3 years. The report card should be in a common format that enables a side-by-side comparison.*

The OEB endorsed the recommendations from the Staff Report and initiated the development of this Framework.

3. The Framework

The OEB expects that the implementation of the Framework will introduce greater transparency, accountability and performance measurement to the review of gas supply plans to ensure that customers are receiving value from the distributors' gas supply activities. The Framework builds on prior consultations and the OEB's experience in reviewing distributors' gas supply plans.

The approach set out in the Framework ensures transparency by requiring distributors to publicly file a comprehensive five-year gas supply plan once every five years and annual updates. The assessment process will provide customers and other stakeholders the opportunity to file comments with respect to the gas supply plans. In addition, clearly defined principles are established that the OEB will apply in the assessment of the gas supply plans, which ensures that both customers and the distributors understand how the gas supply plans will be considered.

Distributors maintain responsibility to develop and execute their gas supply plans and are accountable for the outcome. To this end, performance metrics will assist the OEB in assessing whether the gas supply plans are achieving the Framework's guiding principles. The Framework places a greater emphasis on the customer impact of the gas supply decisions that are made on their behalf. This will include an assessment of costs, risks and volatility of the plan.

3.1. Guiding Principles for the Assessment of Gas Supply Plans

The OEB is of the view that a principle-based approach to gas supply planning is an effective means of guiding the distributors' approach to developing a gas supply plan that is consistent with the outcomes customers' desire. In assessing a gas supply plan, the OEB will focus on determining whether or not a distributor has successfully balanced all of the guiding principles. Guiding principles also help provide consistency, clarity and predictability in the OEB's assessment of the plans.

The OEB has defined guiding principles that are consistent with its legislated mandate to protect the interests of customers with respect to price and the reliability of gas service. The guiding principles for a distributor's gas supply plan are to deliver gas supply that is cost-effective, reliable (secure) and achieves public policy objectives.

1) <u>Cost-effectiveness</u> – The gas supply plans will be cost-effective. Cost-effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner.
2) <u>Reliability and security of supply</u> – The gas supply plans will ensure the reliable and secure supply of gas. Reliability and security of supply is achieved by ensuring gas supply to various receipt points to meet planned peak day and seasonal gas delivery requirements.

3) Public policy – The gas supply plan will be developed to ensure that it supports and is aligned with public policy where appropriate.

For clarity, cost-effectiveness does not necessarily mean the “lowest cost,” reliability does not mean “reliable at any cost” and support for public policy does not mean “support at any cost” or “any level of reliability.” Rather, the intent is to strike a balanced approach to the benefit of customers. Distributors are required to demonstrate that their gas supply plans balance the principles in a way that is prudent and appropriate for customers. It is expected that distributors will employ strategies that clearly describe their approach, customer impacts and risks associated with both the options considered and chosen to deliver value to customers.

3.2. Framework Criteria

The information requirements set out below will be used by the OEB to evaluate a distributor’s plan to assess whether it meets the principles and delivers value to consumers. Gas distributor’s plans must meet specific criteria established by the OEB and the gas supply plan should include a description of how the criteria have been met.

3.1.1. Demand Forecast Analysis

The development of demand forecasts is the starting point for gas supply planning. Distributors prepare demand forecasts so that they can determine the appropriate portfolio of transportation and storage assets required to meet customer demand. Distributors will use these forecasts to inform the development of their plans and also for the purposes of cost allocation and rate-setting. Distributors already prepare volume forecasts and the OEB expects the distributors to use its OEB-approved methodology when preparing a gas supply plan.

As part of the review of a gas supply plan, the OEB will assess whether the distributor has demonstrated they have considered the appropriate factors that could impact the demand forecasts. In presenting their demand forecasts, distributors should describe the process they undertake to develop the forecast and describe the associated risks with their approach. For example, distributors should describe factors such as historical demand, customer demographic trends, changing weather patterns and how they impact the forecast. In its assessment of the gas supply plan, the OEB will consider whether the distributors have appropriately supported their decision and incorporated an understanding of current and future trends. A detailed description of this along with a rationale that supports their approach will assist the OEB in understanding how distributors undertake this task and the potential customer impact.

3.1.2. Supply Option Analysis

The OEB will assess whether the distributor has demonstrated that their gas supply plan balances cost with the other outcomes described in the guiding principles. The gas supply plan will describe the options that were considered and how the selected option was determined. The description will need to include an analysis of the landed cost and bill impact(s) of the options examined, identify the risk associated with each option and how the options align with the guiding principles. This approach will be applied to the development of the distributor’s transportation, storage and supply strategies within the gas supply plan.

To effectively demonstrate that the plans have considered a variety of options, best- and worst-case scenarios and their impact on customers, distributors will provide information that supports their planning decisions. This will include, but not be limited to, the following:

- A description of a forecast that outlines the current market conditions in Ontario and North America (Market Outlook)at the outset of gas supply planning to provide context for the decisions that distributors make.
- A description of the costs associated with the various options considered and how the final option(s) was/were selected.
- Analysis of the bill impact of options considered and how these compare to the selected option(s), including a description of the considerations used to determine the final plan.
- A description of how the options considered the impact of price volatility as a result of various supply/demand scenarios and how the distributor determined what level of volatility was deemed acceptable for customers.
- A description of the various options considered to deliver reliable supply to customers and why the final option(s) was/were chosen.
- Analysis of the cost and bill impact of options considered and how these reliability options compare to the selected option(s), including a description of the considerations used to determine the final plan.
- A description of the distributor’s approach to balancing reliability and flexibility (including planned discretionary supply) within its plan and the cost and risk trade-offs associated with their approach.
- A description of how the distributor built supply and transportation route diversity into the plan and the cost implications and risks associated with their approach.

An expected outcome for the gas supply plan is that it provide the flexibility to respond to changing market conditions while balancing cost-effectiveness and maintaining reliability of supply. One of the ways distributors have historically done this is to procure less supply than they have contracted pipeline capacity to ship. This provides the distributor with an opportunity to sell capacity or procure supply to meet demand and changes in requirements. The gas supply plan must describe how the distributor has determined these quantities and identify the risks associated with their approach along with the impact on customers, including the costs associated with unutilized assets.

The analysis of supply options will also provide the distributor with the opportunity to identify new sources of supply through renewable natural gas (RNG). Building this new supply into its plan may require the distributor to expand on areas such as supply development, flexibility and value to customers.

3.1.3. Risk Mitigation Analysis

Distributors develop a gas supply plan that supports the needs of its customers as identified through the demand forecast, and in doing so also manages both the cost and reliability-related risks on behalf of their customers. Increased reliability typically costs more and distributors are expected to determine the appropriate balance. Distributors will articulate their approach by including a suite of scenarios that describe the envelope of plan forecasts based on worst, best and most likely cases, in addition to their selected option(s). This accompanied by commensurate price forecasts for customers can describe the range of realistic outcomes. By describing the potential causal events that would lead to those outcomes, the OEB will be in a better position to understand the implications of the plan, its flexibility and impacts.

One of the underlying themes of the consultation on distributor gas supply planning was the topic of risk and the cost to mitigate it. Currently in Ontario, distributors manage the gas supply portfolio by balancing cost and reliability. During prior consultations, stakeholders had difficulty understanding how the distributor's objectives for the plan were linked to some of the decisions that distributors make. For example, distributors assess the risk/cost trade-off between procuring landed supply or procuring closer to the production source but the inputs to the final decision and a description of the alternative options were not articulated in a meaningful way in the gas supply memoranda.

Under the Framework, the gas supply plans will have to provide a clear description of the risk management process (identification and mitigation) and an assessment of the risk/cost trade-off implications for customers that are associated with options examined. This will include, but not be limited to, a description of the how the distributors' plans will address demand forecast variability and price volatility. Gas supply planning strategies should be flexible so that they can adapt to changing market conditions and customer demand in both the short-term and long-term. Gas supply planning should also minimize risk by diversifying contract terms, supply basins and upstream pipelines, and other strategies designed to maintain a viable gas industry in Ontario. This information will assist the OEB in assessing the differences in risk profiles for the various options as well as for the respective distributors. The OEB will assess the distributor's approach to managing risk to determine if the approach is reasonable and in line with customer expectations.

3.1.4. Achieving Public Policy Objectives

The distributor is to identify and demonstrate the public policy that their gas supply plan is supporting and how they've balanced achieving this with the other guiding principles in this Framework. They should be public policy initiatives that are in effect rather than proposed public policy initiatives.

3.1.5. Procurement Process and Policy Analysis

Once the transportation and storage strategies have been established, the execution of the gas supply plan is based on the distributors' respective gas procurement policies. The gas supply plan will include an overview of these policies along with a description of how the distributor monitors the market and what resources are applied to ensure that it meets demand.

In addition, the distributors should describe the "triggers" and other considerations that require it to take action (e.g., sell/procure more gas, sell/procure transportation, curtailment or storage), the options available and the risks associated with their approach, along with the impact on customers. The distributors should be mindful that a description of triggering events does not impact the markets and therefore negatively impact customers.

Distributors will need to provide a robust description of the internal processes and level of expertise associated with developing, reviewing, approving and executing the gas supply plan. For example, distributors in the past have used consultants to provide market forecasts and analysis that were used to inform their plans. Distributors should provide a description of the work completed by third parties and how their work is considered when developing the gas supply plan.

3.1.6. Performance Measurement

It is expected that a distributor will develop performance metrics that reflect the criteria the OEB has established to demonstrate how the principles have been achieved. The measures should demonstrate the value proposition for customers and how it balanced the Framework's guiding principles. Effective metrics will allow the OEB to focus its assessment on results that deliver value for customers and not a line-by-line review of expenditures.

Distributor performance metrics should link directly to one or more of the gas supply plan criteria and be chosen to illustrate the benefits expected from the gas supply planning decisions the distributor has made. Performance metrics are generally quantitative measures that will be used to assess whether the principles have been achieved. However, qualitative measures, such as increased reliability, may also be considered. Performance metrics ensure that the outcomes are measurable in keeping with one of the objectives of the Framework.

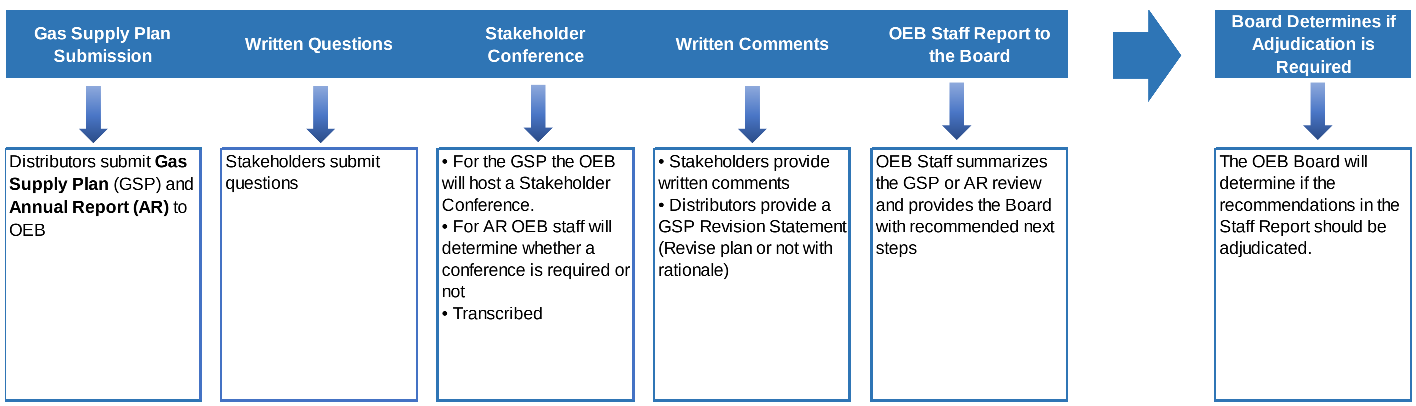
In reviewing distributors' performance metrics, the OEB's considerations are:

- A focus on strategy and results, not activities.
- Demonstration that distributors consider opportunities for continuous improvement in their planning.
- Demonstration of value to customers.
- Performance metrics that will accurately measure whether the plans are cost-effective and reliable and support public policy.

The performance metrics of the gas supply plans should reflect the Market Outlook and the critical elements of the plan that the distributor intends to use to meets its demand requirements. At a minimum, distributors should use the Market Outlook section of their gas supply plans as the basis for developing performance metrics. The Framework's filing requirements provide more information about what is to be included in the outlook.

4. Gas Supply Plan Assessment

The Framework outlines a robust process for the review of distributors' gas supply plans, in particular to achieve the transparency that has been endorsed by the OEB. Given the importance of gas supply-related costs to natural gas customers, the process must ensure adequate participation and engagement. Gas supply plans play an important role in a number of different OEB processes, discussed further below. Therefore, it is important to consider how the process for the review of the plans can contribute to these other proceedings to deliver greater value to customers.



4.1. Gas Supply Plan Submission

The OEB requires the distributors to submit a five-year gas supply plan for review every five years. The OEB believes that five years is an appropriate period for a robust review of the gas supply plans because it allows for an efficient use of resources for all stakeholders. This review will provide the main OEB assessment of the cost consequences using the criteria set out in the Framework.

During the years between the gas supply plan reviews, an annual supply plan update will be submitted to provide the OEB and stakeholders with an opportunity to examine changes in the demand forecast and the market, reflecting on the previous year's actual comparison to their plan. The depth of review of the update will be contingent on the level of divergence from the five-year gas supply plan.

The filing requirements attached as an Appendix to this Framework provide an overview of the type of information that is expected to be contained in the distributor's gas supply plan submissions. These filing requirements have taken into consideration the type of information identified in prior consultations. The filing requirements will provide the OEB with the information necessary for the review and assessment of a distributor's plan for alignment with the principles set out in the Framework.

4.2. Stakeholder Engagement

Distributors will submit their gas supply plan to the OEB in accordance with the timing to be established by the OEB. The OEB will provide stakeholders with the opportunity to submit written questions about the plan prior to the stakeholder conference and final written comments after the conference. The stakeholder conference will be transcribed and will provide an opportunity for the distributor to present its plan and address questions from stakeholders about the manner in which the guiding principles are achieved. All material will be posted on the OEB's website.

Distributors, based on feedback received from the stakeholders and OEB staff, may choose to provide written comments or revise their plans after the stakeholder conference. Distributors will provide a gas supply plan revision statement that describes the plan revisions with supporting rationale underpinning their decision.

4.3. Staff Report to the OEB

OEB staff will prepare a report to the OEB providing its assessment of the plan. The OEB staff report will be informed by the stakeholder conference and written submissions. Following consideration of the OEB staff report, the OEB may determine that a proceeding is required to address specific issues highlighted by the staff report. Unless the OEB decides to hold a proceeding to consider the distributor's plan, the five-year review process would end with the OEB staff report.

4.4. Annual Gas Supply Plan Updates

Distributors are required to provide an annual gas supply plan update. The annual gas supply plan update is an important tool for distributors to identify significant events that result in a change to the gas supply plans. They will primarily focus on updates to the Outlook section of the gas supply plan, a description of significant changes from previous updates and a historical comparison of actuals to the Outlook. The content and format of the updates can be found in the Filing Requirements.

The review and assessment of the Update will be carried out in a manner similar to the five-year gas supply plan. The OEB will determine if the update submitted has significantly diverged from the five-year plan, and would benefit from holding a more in-depth evaluation. OEB staff will prepare a report to the OEB providing its assessment of the update. The timing of the update and review may be co-ordinated with other related applications from the distributor.

5. Links to other Applications

It is expected that information provided in the gas supply plan will be used to inform other gas supply-related applications submitted to the OEB. The gas supply plan assessment under the Framework is expected to provide for greater efficiency in these other related application processes. Distributors will retain the responsibility to support their gas supply plans in these other applications in a manner that promotes regulatory efficiency and avoids duplication and overlap.

5.1. QRAM

The gas supply plan describes the most likely outcome and cost envelope (best/worst case) of the distributor's planning activities over a five-year forecast period. In addition, the annual updates will include any adjustment to the forecast and a comparison of actuals with what was forecast for the previous 3 years. With the annual update filings, distributors can demonstrate how changes to the gas supply plan compare to their forecasts in QRAM. This provides a baseline for assessing actual costs compared to forecasted costs and the impact on the customers' rates.

5.2. Leave to Construct

In some cases, leave to construct applications are centred on improving cost effectiveness/reliability for customers. The gas supply plan provides distributors with a consistent mechanism to demonstrate how some specific types of projects will deliver value to customers and can be used to measure the impact over time to determine if the distributor's assessment of benefit was accurate. In addition, the gas supply plan can highlight the need for additional facilities to support demand and provides a link to the distributor's Utility System Plan.

5.3. Long-Term Contracts

Applications for pre-approval of long-term contracts often focus on the value to customers in terms of cost, reliability and public policy. The gas supply plan will provide a mechanism for the distributor to demonstrate the value to customers of the proposed long-term contract (e.g., NEXUS) and the ability to measure the outcome over time.

5.4. Rate Applications

As discussed earlier, distributors' rate applications have or may have an impact on gas supply, transportation and storage rates. The gas supply plan offers a consistent basis to demonstrate how the distributor's gas supply plans and decisions may affect rate applications, including capital plans for new facilities.

6. Monitoring the Framework in meeting the OEB's Objectives

The OEB expects that over time, experience and lessons learned will provide insight into aspects of the Framework that can be further enhanced and strengthened. After the first five-year plan has been completed and implemented, the OEB will assess the Framework and the review process against the following outcomes:

- The regulatory expectations in relation to gas supply planning inputs are understood by the gas utilities and all gas supply stakeholders.
- The regulatory approach to assessing gas supply plans is clear and consistent.
- The application of OEB performance metrics on the outcomes of gas supply planning result in positive outcomes for customers.

The OEB will monitor, evaluate and report on whether the expected policy outcomes for the Framework are being met over time.

Appendix

Filing Requirements – Distributor Gas Supply Plans

These Filing Requirements are intended to assist distributors in preparing their gas supply plans in order to align with the OEB's Framework. The guidelines outline the minimum information necessary to be filed by gas distributors in order for the OEB to review their gas supply plans and gas supply plan updates.

These requirements provide direction to the distributors on the content of their plans. The requirements should be read in conjunction with the Framework to fully understand the intention behind the requirements.

1. General Gas Supply Plan Requirements

The plans and updates are to be submitted to the OEB by deadlines established by the OEB. The basic information that distributors must include with their gas supply plans are outlined in this section.

1.1. Administrative Information

- Table of Contents
- Introduction – The introduction should include a summary of the objectives of the plan and, at a high level, how the plan achieves the Framework's guiding principles.
- Significant Changes – To facilitate a more efficient review of the plans, distributors will describe the significant changes to the plan from the previously submitted plan and the resulting customer impact.
- Process, Resources and Governance – Distributors will provide a description of the internal processes and level of expertise associated with developing, reviewing, approving and executing the gas supply plan. For example, distributors in the past have used consultants to provide market forecasts and analysis that were used to inform their plans. Distributors should provide a description of the work completed by third parties and how their work is considered when developing the gas supply plan.

1.2. Gas Supply Plan Criteria

A description of the following gas supply plan criteria:

1) Demand forecast analysis
2) Supply option analysis
3) Performance metrics
4) Risk mitigation analysis
5) Achieving public policy
6) Procurement process and policy

The plans should focus on both the risk and impact to the customers. To effectively demonstrate that the plans have considered a variety of options and their impact on customers, distributors will provide information that supports their planning decisions. This will include, but not be limited to, the following:

- A detailed description of the process they undertake to develop the demand forecast and describe the associated risks with their approach.
- A detailed description of the rationale that supports their approach to developing their demand forecast, the options considered and their impacts on customers.
- A description of the costs associated with the various options considered and how the final option(s) was/were chosen.
- Analysis of the bill impact of options considered and how these compare to the chosen option(s), including a description of the considerations used to determining the final solution.
- A description of how the options considered (and chosen) impact price volatility and predictability and how the distributor determined what level of volatility was deemed acceptable for customers.
- A description of the various options considered to deliver reliable supply to customers and why the final option(s) was/were chosen.
- Analysis of the cost and bill impact of options considered and how these reliability options compare to the chosen option(s), including a description of the considerations used to determining the final solution.
- A description of the distributor’s approach to balancing reliability and flexibility within a plan and what the cost and risk trade-offs are associated with their approach.
- A description of how the distributor built supply and transportation route diversity into the plan and what the cost implications and risks are associated with their approach.

1.3. Gas Supply Plan Outlook

The performance metrics of the gas supply plans should provide a quantitative forecast, or Outlook, of the following outputs of the plan that the distributor plans to use to meet its demand requirements. The performance metrics should describe how the plan is performing versus the forecast and should be meaningful to customers. At minimum, the Outlook section of the gas supply plan should include the following:

- Forecasted demand
- Commodity and other market-based solutions portfolio
- Renewable natural gas portfolio
- Transportation portfolio
- Storage portfolio
- Unutilized capacity
- Long-term contracts
- Other solutions that the distributor determines will be used to meet its demand requirements

1.4. Gas Supply Plan Execution

The gas supply plan should include an overview of the natural gas procurement policies used by the distributors and a description of the triggers that signal that action is required. This section will also include a description of the flexibility built into the plan, how these quantities were arrived at and what the impacts are for customers.

1.5. Description of Continuous Improvement Strategies

Continuous improvement to the gas supply planning task undertaken by the distributors is an important element of the transparency objective of the Framework. Distributors are expected to include areas of improvement in their plans.

1.6. Link to Other Applications

Distributors should describe how their plans link to other applications submitted to the OEB and highlight the bill and rate impacts of applications on the gas supply plan. If at a later date the distributor submits an application that appears to have an impact on the gas supply plan, the distributor will be required to describe why the gas supply plan impact was not included.

1.7. Three-Year Historical Review

The gas supply plan should include a review of the prior three years comparing the

Outlook included in the gas supply plan to actual data.

2. Annual Gas Supply Plan Update General Requirements

Distributors will submit an annual gas supply plan update (Update) to the OEB for review. The Update will include a three-year analysis of actual data that the OEB can compare to the data the distributor included in the Outlook section of the gas supply plan.

The following sections describe the minimum information that distributors are to include in their Update.

2.1. Significant Changes to the Gas Supply Plan

The Update should describe the significant changes to the plan from the previously submitted Update and the resulting customer impact.

2.2. Updated Gas Supply Plan Outlook

The Update should include updated data for the five-year Outlook.

2.3. Three-Year Historical Review

Distributors will include a three-year historical comparison of actuals to the Outlook similar to the comparison that would be included in the gas supply plan.

3. Submission Schedule

3.1. Gas Supply Plans

January 1, 2019 – Initial five-year gas supply plan for the following implementation year is due. For example, if the distributor’s planning period is January to December, the initial five-year plan will be for the period January 1, 2020, to December 31, 2024. Similarly, if the gas supply planning period is from November to October, the initial five-year plan will be for the period November 1, 2019, to October 31, 2024.

January 1, 2024 – Second five-year gas supply plan for the following implementation year is due.

3.2. Annual Updates

May 1, 2019 – Initial annual update for the prior three years and the following three years. Annual updates are required to be submitted to the OEB every year following the implementation of this Framework.

TAB 5 - Northeast Gas Association, "The Role of LNG in the Northeast Natural Gas (and Energy) Market"

About LNG

The Role of LNG in the Northeast Natural Gas (and Energy) Market

Introduction

Liquefied natural gas (LNG) is natural gas (primarily methane) that has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit. It can be compressed, stored and transported over long distances by ship; and then stored on land in specially-designed storage facilities. The liquefied gas can then be reheated, converted to vapor, and injected into a pipeline system, for distribution throughout a gas system. It can also be transported to local utility storage tanks via truck.

LNG has traditionally been used for supplemental supplies, particularly for winter peak periods. It is also important in particular areas (like parts of New England) to help maintain system pressures at different points of the regional natural gas system. It is a fuel with multiple applications, from powering electric power plants to fueling heavy-duty trucks and water ferries, among other applications.

LNG can help meet demand for natural gas, and provide supply flexibility to the natural gas and energy marketplace.

LNG has an excellent safety record in all its facets - shipping, trucking and storage. The Northeast Gas Association (NGA) runs an annual program with the Massachusetts Firefighting Academy on LNG. The school has been in operation over 25 years, training personnel from utilities, pipelines, and local fire departments.

Use of LNG in the Northeast

Photo of LNG delivery at Everett, MA during snowstorm, Jan. 2018

LNG remains an important fuel for New England - providing about 28% of design day supply in the winter for local gas utilities. LNG provides about 10% of New England's total annual gas supply.

There is no underground storage located in New England (geologic unsuitability.) LNG is thus an important part of the region's supply and deliverability network.

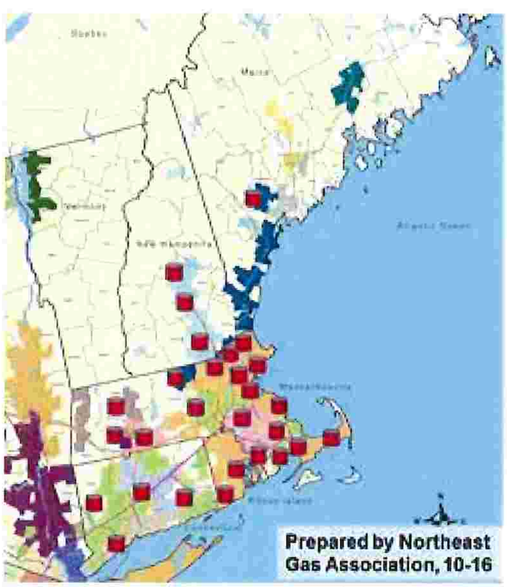
There are liquefaction and satellite storage tanks in localities in the region that are owned and operated by the local distribution companies (LDCs).

In 2018, according to NGA, the LNG storage capacity in New England among the local distribution companies (LDCs) was 16 Bcf (which does not include the storage at the Everett LNG terminal). Vaporization capacity for daily sendout by New England gas LDCs was approximately 1.4 Bcf/day; and liquefaction capability by the LDCs was 43,500 MMBtu/day.

LNG is also part of the utility supply portfolios in New Jersey, downstate New York and Pennsylvania.

LNG is utilized by several LDCs in New Jersey, with total state storage capacity of about 4 Bcf. One utility added liquefaction capability in 2016.

LNG in New York is obtained by liquefaction of pipeline gas. Two LDCs maintain LNG peak-shaving plants. The facilities provide service area system reliability as well as assist in meeting peak day requirements. These facilities have storage capacity of approximately 3.2 Bcf, liquefaction capability of 16,800 Mcf/day, and a vaporization rate of approximately 26,100 Mcf/hr.



Natural gas utilities in New England own and operate LNG storage tanks as a key part of their winter supply portfolio. Total LDC LNG storage capacity is 16 Bcf.

One utility in southeastern Pennsylvania uses LNG for injection into its system, with total storage capacity of about 4.25 Bcf at two plants. It receives LNG through both liquefaction and trucking. Another PA gas utility operates an LNG liquefaction plant with storage capacity of 1.25 Bcf; through a subsidiary, it provides delivery of LNG by truck to serve Mid-Atlantic and New England markets.

Imports in the region (and in the U.S.) have been on the decline in recent years as U.S. domestic natural gas production has been on the increase. With its more limited pipeline infrastructure, the Northeast and especially New England, however, remain key markets for LNG. The import terminals near Boston and in New Brunswick are well-positioned to respond to market conditions if contract arrangements are in place.

Recent LNG Imports into New England

Everett LNG in 2018 imported 56.3 Bcf, while U.S. LNG imports totaled 71.7 Bcf (source: U.S. Department of Energy, Office of Natural Gas Import and Export Activities).

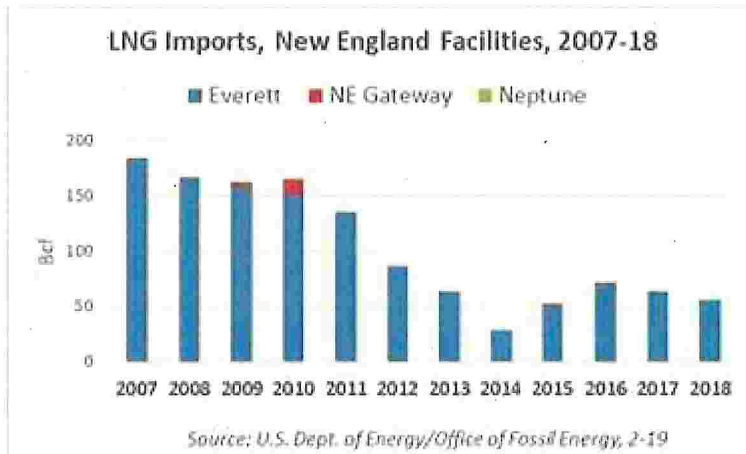
There were no LNG imports by the offshore Northeast Gateway facility in 2017 or 2018. However, the facility did bring cargoes to the region in January/February 2019 and injected volumes during cold weather periods.

As in the U.S., New England LNG imports reached their highest level in recent years in 2007.

New England also receives supplies from the Canaport LNG facility in Saint John, New Brunswick, Canada. The facility is located about 60 miles from the Maine border. Canaport is a joint enterprise of Repsol and Irving Oil. In 2018 it imported approximately 21 Bcf, compared to 14 Bcf in 2017. (source: National Energy Board of Canada).

Storage tanks at Exelon Generation, Everett LNG facility

Import Facilities in New England



There are three import facilities in New England: the Exelon Generation, Everett LNG facility in Everett, MA; the Northeast Gateway facility offshore Cape Ann, MA; and the Neptune facility offshore Cape Ann, MA.

Everett LNG, formerly known as Distrigas, is a subsidiary of Exelon Generation. Its Everett, MA facility has been in operation since 1971. It has storage of 3.4 billion cubic feet (Bcf). The terminal's maximum installed vaporization capacity is about one billion cubic feet per day; on a sustainable basis, the vaporization capacity is approximately 700 million cubic feet per day. It also has sendout capability of 100,000 MMBtu/day by truck, which supports local storage refills for local gas utilities throughout the region. The terminal is directly connected to the interstate pipeline network and to National Grid's local distribution system in the Boston area. In 2003, a nearby power plant with two units, with total nameplate capacity of about 1,500 megawatts, entered service, fueled by LNG from the terminal. Everett has received over 1,200 cargoes. In March 2018, Exelon Generation announced an agreement to purchase the LNG terminal from its longtime owner ENGIE North America, "to ensure the continued reliable supply of fuel to Mystic Units 8 and 9 while they remain operating." The transaction was finalized in fall 2018.

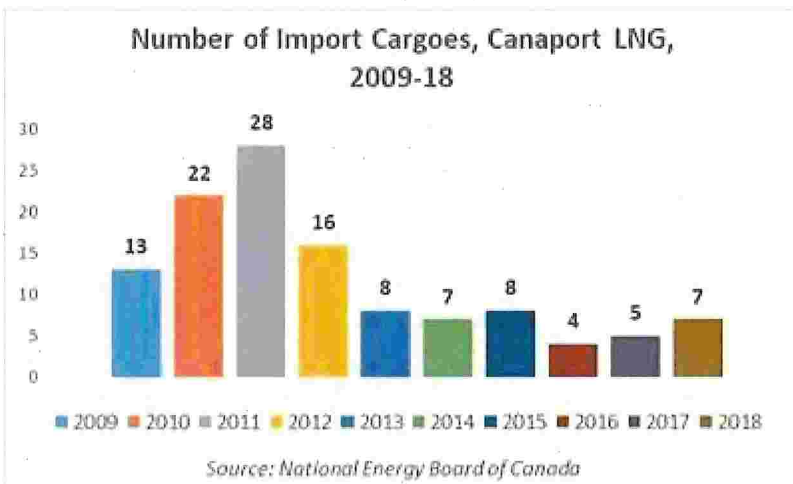
The Northeast Gateway facility is owned and operated by Excelerate Energy. The facility began commercial operations in May 2008. Operating approximately 18 miles east of Boston in Massachusetts Bay, the offshore LNG facility is capable of injecting vaporized natural gas into the existing offshore HubLine natural gas pipeline system operated by Spectra/Enbridge. The offshore facility has varied in its levels of imports over the years. It imported several cargoes from 2008 to 2010, but no cargoes from 2011 to 2014. It brought volumes in for deliveries into the New England market in early 2015 and early 2016, during the high-demand peak winter months; but then no cargoes in 2017 or 2018. It provided volumes in early 2019 during several high demand cold weather days.

The Neptune LNG facility was developed in 2010 by ENGIE, which also operated Distrigas at that time. The facility is located approximately 10 miles off the coast of Gloucester, MA. The Neptune port consists of a buoy system where LNG vessels could moor and discharge natural gas by using onboard vaporization equipment. It is capable of injecting about 0.4 Bcf per day of gas into the pipeline system from a special regasification system on-board its delivery vessels. However, it has not been active since its start-up. Several years ago, the U.S. Maritime Administration (MARAD), part of the U.S. Department of Transportation, approved the request of Neptune LNG LLC (Neptune) for continuation of the suspension of port operations at the Neptune Deepwater Port (Neptune Port) by amending the Neptune Deepwater Port License (License). On December 22, 2017, MARAD received a written request from Neptune for authorization to temporarily suspend operations at the Neptune Port. In the request, Neptune indicated that conditions within the Northeast region's natural gas market continue to impact the Neptune Port's ability to import liquefied natural gas (LNG). As a result, the Neptune Port has remained inactive over the past several years and will likely remain inactive for the foreseeable future. For these reasons, Neptune requested MARAD's authorization to formally suspend port operations for a period of four years. The suspension period became effective June 26, 2018, and will extend for a period of four years, to be measured in calendar days - or until mid-2022.

Canaport facility, New Brunswick, Canada (photo: Repsol)

E. Canada Import Facility

In June 2009, the Canaport LNG terminal in Saint John, New Brunswick, Canada began operation. It was developed by Repsol and Irving Oil. It has 3 storage tanks; each tank can hold 3.3 Bcf. It is capable of moving on average over 700 million cubic feet per day into the Brunswick Pipeline and then the Maritimes & Northeast Pipeline for delivery into Maine and New England. Its markets are in the Maritimes, New England and the Northeast. Since its inception, it has introduced over 400 Bcf into the market.



U.S. Exports of LNG

With the strong rise in U.S. domestic production, there is strong market interest in developing LNG export facilities in the U.S. A number of companies have filed with the federal government for export licenses. Canada is also considering export facilities, with projects most likely advancing on its West Coast.

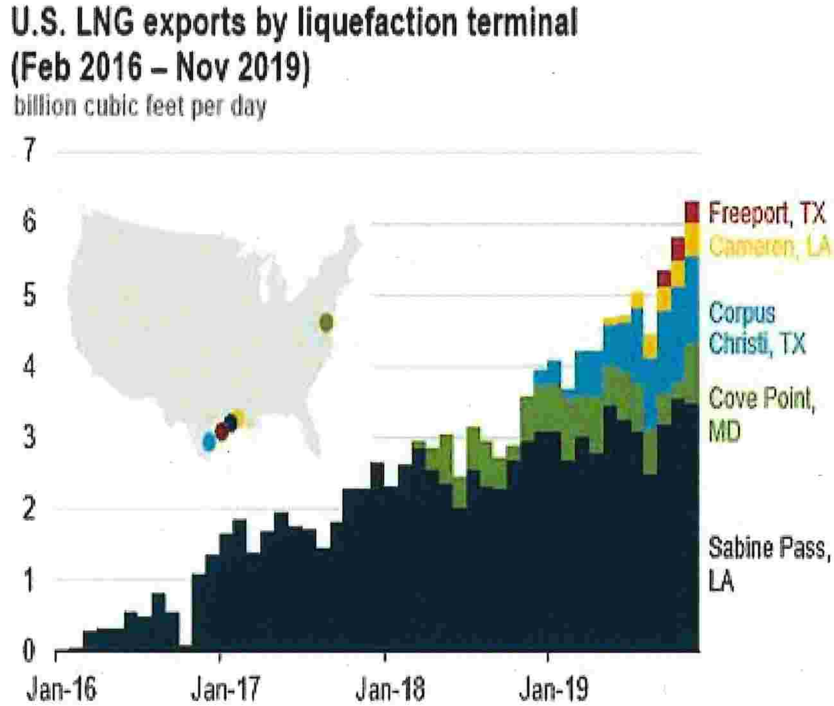
Dominion last year repurposed its Cove Point facility in Maryland, long an import facility, into an export facility. It commissioned its first export cargo in March 2018. U.S. EIA noted on March 8, 2018 that: "Cove Point has a design capacity to liquefy up to 0.75 billion cubic feet per day (Bcf/d) of natural gas. The natural gas is sourced from the high-producing Marcellus and Utica shale plays. Cove Point is the only LNG export facility on the east coast of the United States and was the second export facility operating in the Lower 48 states after Sabine Pass in Louisiana, which began commercial operations in 2016."

The U.S. Department of Energy maintains a list of export facility project applications; the list is posted online ((http://energy.gov/fe/downloads/summary-lng-export-applications-lower-48-states).

In 2018, the U.S. exported just over 1,000 Bcf (or 1 Tcf) of LNG by vessel (compared to imports of 71.7 Bcf). The level of U.S. exports is expected to rise further in coming years as more facilities come online.

Portable LNG (and CNG)

A relatively new development is the introduction of portable or mobile LNG and CNG (compressed natural gas) to bring natural gas to industries and businesses not located near a pipeline system or within a distribution service area. Some areas and businesses in northern New England and New York, for instance, not connected to local gas systems, are opting for gas (LNG or CNG) delivered by truck to meet energy needs. The gas is transported via a trailer that also can serve to offload the gas into the facility. This is currently being utilized to serve paper mills, farms and other entities.



Source: U.S. EIA, 12-19

LNG for Transportation

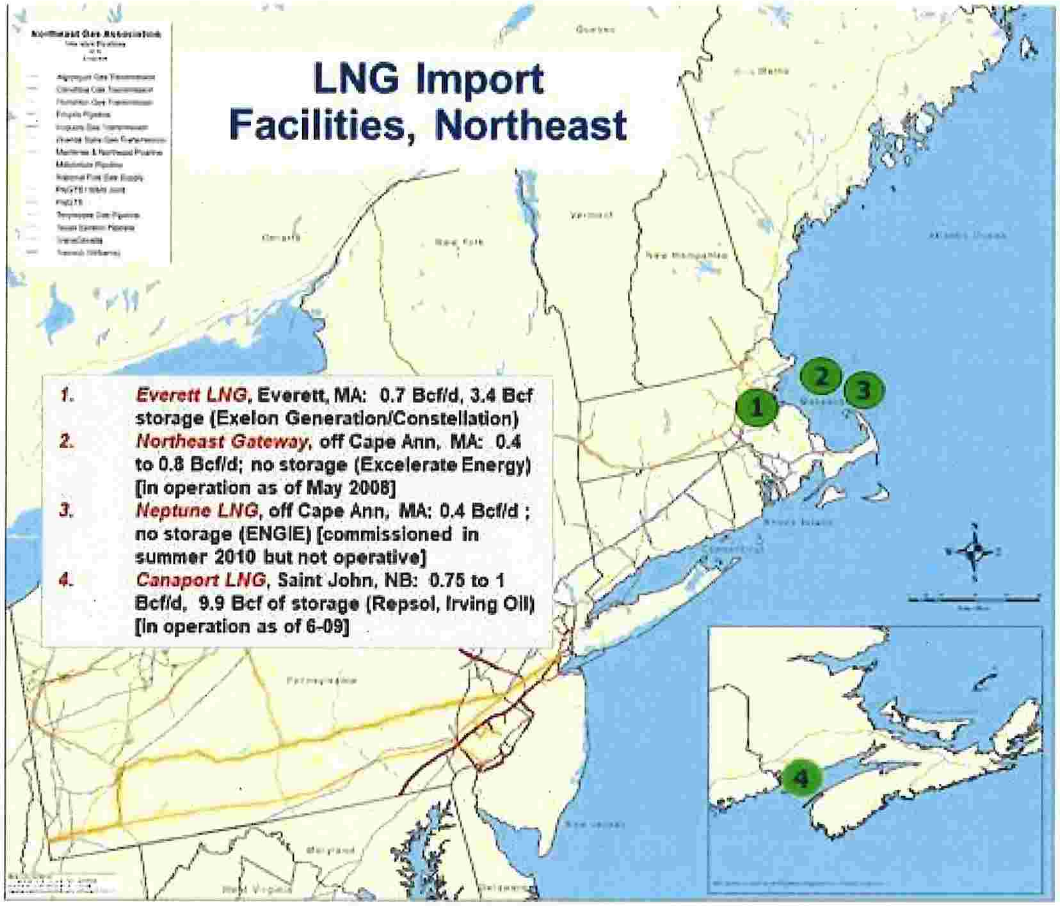
The value of natural gas is also leading some companies with vehicle fleets to consider CNG and also LNG as a transport fuel. LNG is of greatest interest for heavy-duty trucks that travel long distances. In Canada, Gaz Métro introduced the "Blue Highway" concept, adding LNG fueling infrastructure from Québec City to Toronto. Distrigas has added LNG fueling at its Everett facility.

In 2012, ANGA released a study on LNG as a transportation fuel. It notes: "LNG has higher energy density than CNG and thus offers significant potential in NGV market segments where long vehicle ranges are required. Because LNG must be stored at extremely low temperatures, the tanks required to maintain these temperatures on vehicles are large. As such, LNG is most appropriate for heavy-duty vehicles, which can accommodate the volume needed for LNG storage."

LNG is also suitable for fueling of marine transport-such as water ferries-and rail.

LNG Terminals in Northeastern North America

A map of the operating facilities is shown here.



For Further Information

Exelon Generation, Everett LNG

Repsol Energy North America / Canaport LNG

Excelerate Energy/Northeast Gateway Deepwater Port

LNG/LP Firefighting & Safety Training - NGA and Mass. Fire Academy

U.S. Dept. of Energy / Fossil Energy

NARUC Report on LNG Market, 11-18

Northeast Gas Association
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NYSEARCH/NGA
20 Waterview Boulevard, 4th Floor, Parsippany, NJ 07054 / Phone 973.265.1900 / Fax 973.263.0919

TAB 6 - OF-Tolls-Group1-T211-2018-01 01, National Energy Board Letter Decision, December 4, 2018 - A96353-1

LETTER DECISION

OF-Tolls-Group1-T211-2018-01 01
4 December 2018

Mr. Alan L. Ross
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Mr. Kevin Thrasher
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Dear Mr. Pelletier, Mr. Thrasher, Mr. Ross and Mr. Samuel:

Nipigon LNG Corporation (NLNG)
Application pursuant to Section 12, Section 13, Section 59, Subsection 71(2), Subsection 71(3) and Part IV of the *National Energy Board Act* (NEB Act) in respect of TransCanada PipeLines Limited (TransCanada) and the TransCanada Mainline pipeline system (the TransCanada Mainline)

The Application

On 12 October 2018, the National Energy Board (Board) received an application from NLNG pursuant to sections 12, 13, 59 and 71 of the NEB Act requesting the Board direct TransCanada to provide facilities, and service under just and reasonable terms, to connect and transport gas from the TransCanada Mainline to its planned liquefied natural gas (LNG) project (the Application). In the Application, NLNG has requested the following relief (collectively, the Orders):

a) for an Order, pursuant to subsection 71(3) of the NEB Act, directing TransCanada to provide adequate and suitable facilities for the interconnection of the Nipigon LNG Project (the Project) with the TransCanada Mainline at a point on the Northern Ontario Line (the NOL) segment of the TransCanada Mainline west/upstream of TransCanada's Nipigon Compressor Station in the unorganized Township of Ledger (the Ledger Interconnection) by 30 June 2020;

…/2

b) for an Order, pursuant to subsections 71(2) and (3) of the NEB Act, directing TransCanada to establish a new delivery point at or near that location of the Project by 30 June 2020;

c) for an Order, pursuant to subsection 71(2) of the NEB Act, directing TransCanada to transport and deliver, on a firm basis, up to 7,200 GJ/day of natural gas to NLNG, commencing June 30, 2020, or so soon thereafter as is reasonably practical in the circumstances (Ledger Delivery); and,

d) for an Order, pursuant to section 59, section 71 and Part IV of the NEB Act, prescribing just and reasonable terms for the Ledger Delivery, including:

    i) service pursuant to terms consistent with TransCanada's standard renewable firm service agreement for an initial period of 10 years; and,

    ii) just and reasonable tolls calculated in a manner determined by the Board.

NLNG submitted that it had been involved, for several months, in ongoing discussions with TransCanada, as it was seeking the Ledger Interconnection and Ledger Delivery on the TransCanada Mainline to deliver gas to the Project. NLNG noted it had applied to the Ontario Energy Board (OEB) for approval of the facilities needed to supply gas to the Project from the Ledger Interconnection.

However, according to the Application, despite the proposed Project not being located in a Local Distribution Company (LDC) franchise area, TransCanada would not proceed with the Ledger Interconnection without written confirmation from the LDCs – Union Gas Limited (Union) and Enbridge Gas Distribution Inc. (EGDI) – that Ledger "is not a current or potential franchise area". According to the Application, TransCanada said that this requirement stemmed from the Mainline Settlement Agreement between TransCanada, Union, EGDI, and Énergir, L.P. (the Settlement) which contained a no-bypass provision whereby TransCanada would not construct facilities to directly serve LDC customers within the LDCs' franchise areas. According to NLNG, TransCanada also noted it would not proceed with pre-work for the Ledger Interconnection until NLNG obtained all provincial approvals.

NLNG submitted that TransCanada's request for NLNG to obtain approval from the LDCs is unreasonable, discriminatory, and contrary to the NEB Act and TransCanada's common law obligations as a common carrier. NLNG submitted that it is not in the public interest for TransCanada to require a new shipper to obtain approval from other shippers to access natural gas from the TransCanada Mainline. NLNG submitted that TransCanada's obstruction had contributed to a delay in the commercial operation date of the LNG plant from October 2019 to October 2020.

NLNG submitted that the Board should find it in the public interest to issue the Orders pursuant to subsections 71(2) and 71(3) of the NEB Act. Requiring TransCanada to provide the interconnection facilities per subsection 71(3), in NLNG's view, will not cause TransCanada undue burden.

Comment Process

On 16 October 2018, the Board solicited comments on the Application and on any further process the Board may hold to consider the Application. The Board requested that interested parties file comments by 24 October 2018, TransCanada file comments by 31 October 2018, and NLNG file any reply comments with the Board by 7 November 2018. The Board noted in its letter that it was particularly interested in comments from TransCanada and any LDCs regarding NLNG's submission that "the proposed LNG Plant is not within any LDC's franchise area". The Board stated that it may issue its ruling on this matter or set out further process to deal with the Application.

Submissions from Interested Parties

The Board received comments from the North Shore Municipalities group on 23 October 2018. The North Shore Municipalities Group, composed of Schreiber, Terrace Bay, Marathon, Manitouwadge, and Wawa, indicated that the Nipigon LNG Project is an essential element of the North Shore Project[1] and is critical to its development.

The Board received comments from Union and EGDI on 24 October 2018. Both Union and EGDI confirmed that the Township of Ledger is not covered by a franchise agreement held by their respective companies. Union noted that as Ledger is an unorganized township, franchise rights cannot be established for the area. Union noted that it does not have plans to expand in this area but may in the future, including the area of the proposed plant.

The Board also received comments from the Canadian Association of Petroleum Producers (CAPP), Centra Gas Manitoba (Centra), and a joint submission from Red Rock Indian Band (RRIB), the Bingwi Neyaashi Anishinaabek (BWA), and the Biinjitiwaabik Zaaging Anishinaabek (BZA) (collectively, the First Nations Group) on 24 October 2018.

The First Nations Group submitted that the RRIB, BWA and BZA have been in consultation with NLNG, and that RRIB, BWA and BZA have a significant interest in realizing both direct economic benefits and community development opportunities from the Project.

CAPP submitted that the Settlement should not be used as a mechanism to allow the eastern LDC's to delay development of natural gas infrastructure in areas that may be of future interest to their businesses, and that the no-bypass provision made by TransCanada and the LDCs should not impede other industry participants from conducting normal business on a federally regulated open access pipeline. CAPP requested the Board grant the relief requested by NLNG.

[1] The North Shore Municipalities Group filed a copy of the North Shore Natural Gas Project Plan with the Board. The filing describes the plan to source LNG from a regional facility, and deliver the LNG to the Municipalities via truck. When there is demand, locally stored LNG will be converted to natural gas and delivered through distribution systems to homes and businesses at the Municipalities.

Centra noted that TransCanada's reliance on the Settlement to deny timely access on the Mainline is unfair, discriminatory, and should not be endorsed by the Board. Centra supported the Board granting the relief requested by NLNG.

TransCanada's Submissions

TransCanada filed its comments with the Board on 31 October 2018. TransCanada submitted that it has always been willing to serve the Project. Contrary to NLNGs submissions, TransCanada is not a common carrier pipeline – which is a designation that only applies to oil pipelines under subsection 71(1) of the NEB Act. TransCanada noted that the Board does have the jurisdiction to order TransCanada to construct facilities, but only if the Board determines that to do so would not cause undue harm to TransCanada.

TransCanada noted that in its view, it was reasonable for it to have regard for its obligations under the Settlement – as the Settlement ended litigation between it and the LDCs, and it was considered by the Board in establishing the Mainline's tolling framework. TransCanada submitted that it was reasonable to seek assurances that the Project did not fall within an LDC's franchise area, but that confidentiality concerns expressed by NLNG prevented it from doing so.

TransCanada noted that if the applied-for Certificate of Public Convenience and Necessity sought by NLNG is granted by the OEB, NLNG will be able to receive gas from the Mainline, regardless of whether Union or EGDI seek to establish a franchise in Ledger in the future. TransCanada submitted that because of the confirmations by Union and EGDI that they do not hold franchise agreements with Ledger, the Orders are not required. Given these confirmations, TransCanada concluded that it could provide the requested service without bypassing Union or EGDI for the sole purpose of serving a customer base of these LDCs. TransCanada indicated it would be prepared to proceed with NLNG's request for service under the normal course of business, which would entail:

i. NLNG's execution of a standard backstopping agreement regarding development costs for the proposed meter station that commits NLNG to execute an firm transportation service agreement;
ii. the addition of a new Distributor Delivery Area (DDA) within Ledger that includes only the new delivery point; and
iii. all necessary regulatory approvals of the Proposed Meter Station and any related facilities, once applied for.

TransCanada added that requiring it to proceed with the interconnection, without sufficient financial backstopping and contractual underpinning for the proposed meter station would place an undue burden on TransCanada and other Mainline shippers. It added that should NLNG execute a backstopping agreement by early 2019, this would provide sufficient time to meet the requested in-service date of June 2020, subject to regulatory approvals.

NLNG's Reply

NLNG submitted its reply comments on 7 November 2018. In its reply, it noted that despite TransCanada's submissions, the orders sought are still required. NLNG stated that the orders sought are still necessary for the Project to proceed on a timely and efficient manner, and that the basis of TransCanada's argument does not resolve all of the issues raised in the Application.

NLNG cited multiple reasons the Orders should still be granted, including:

- There are no objections to the Project;
- A majority of interested parties support the Project;
- The Project is not in a Franchise area, and does not result in a bypass;
- The Settlement or DDA Agreements cannot be used to secure a "maybe" business opportunity for another shipper on a federally-regulated pipeline;
- The Project benefits the Mainline shippers and TransCanada;
- The Project benefits industry, First Nations and other communities; and
- The Project is in the public interest.

NLNG submitted that the only basis for TransCanada's submission is that it has now obtained written confirmation from the LDCs, via this proceeding, that the Township of Ledger is not in a current or potential franchise area. However, NLNG submitted that without the Orders:

a) TransCanada will continue its discriminatory and anti-competitive behaviour;
b) TransCanada will potentially seek to delay or frustrate the Project through other means. Under the Settlement Agreement, TransCanada, Enbridge, and their affiliates have the capacity to work to build competitive threats to the Project;
c) NLNG will potentially refile this Application on some or all of the issues, if denied;
d) The Project cannot proceed. An Order is a requirement for project financing generally, and construction funds in particular.

Subsequent (Unsolicited) Filings

On 8 November 2018, TransCanada provided an additional letter, "limited to matters necessary to complete the record of this proceeding". It noted that regarding its intervention in the OEB process, it submitted it was willing to provide service to the Project in accordance with the Mainline Tariff, and advised of its intention to monitor the OEB proceeding.

On 23 November 2018, NLNG provided the Board with a copy of the OEB's decision regarding works needed to supply the Project. In the decision, the OEB approved a Certificate of Public Convenience and Necessity for the facilities required – approximately 500 meters of 8 inch pipeline - to connect the project to the TransCanada Mainline.

Decision of the Board

Oil pipelines are required to operate on a common carrier basis, under subsection 71(1) of the NEB Act. The same is not true for pipelines transporting gas, but the NEB Act gives the Board the discretion to:

- order a company operating a gas pipeline to provide gas transportation service (paragraph 71(2)(a)); and/or
- require a company operating a gas pipeline to provide facilities required for gas transportation service, gas storage, or the junction of the gas pipeline with other transmission facilities (subsection 71(3)).

The Board's *Filing Manual* provides some guidance for applications under these provisions of the NEB Act:

> *"The Board expects that the applicant under subsection 71(2) or (3) would have requested the subject pipeline operator to provide access or adequate and suitable facilities and that request would have been rejected prior to filing an application."*

Upon receipt of the initial Application, there was a live question as to whether this had been demonstrated. NLNG had requested service, and that request had been held up primarily due to the concern about potential conflict with the no-bypass provision in the Settlement.

However, in the Board's view, several of the issues that were raised in NLNG's initial application have since been dealt with in subsequent filings from TransCanada, Union and EGDI. Given the confirmation from Union and EGDI that the Project is not within either of their existing franchise areas, TransCanada said that it "could provide the requested service without bypassing Union or EGDI for the sole purpose of serving a customer base of these LDCs". TransCanada also said that it would proceed with the interconnection of the Project through its normal course of business, via the execution of a backstopping agreement with NLNG, the addition of a new DDA within Ledger, and application for regulatory approvals. In the Board's view, this is the most appropriate way to advance the Project at this time.

The reasons provided by NLNG to grant the Orders despite TransCanada's commitment to proceed with the Ledger Interconnection, and the recent developments related to the CPCN granted by the OEB, are not compelling.

NLNG listed several reasons why it believes the Project is in the public interest, and noted the support for the project and lack of opposition. The Board does not find these reasons relevant to whether it should exercise its discretion to issue the Orders, in light of TransCanada's commitment to take the necessary steps – including executing a standard backstopping agreement with NLNG, the addition of a new DDA for Ledger, and seeking regulatory approvals – to provide service to the Project. NLNG has not demonstrated – as noted in the *Filing Manual* – that its request for service has been rejected. Nor has NLNG established that TransCanada has unreasonably refused to build any needed facilities. In the absence of any refusal by

TransCanada to provide service or build needed facilities, the Board does not find there is any need or public interest served by issuing the Orders.

NLNG further said that TransCanada will continue its discriminatory and anti-competitive behaviour, but provided no evidence to support this claim. NLNG cited TransCanada's intervention in the OEB process where NLNG was seeking a CPCN regarding the facilities required to connect the Project to the Mainline. Despite this intervention, on 22 November 2018, the OEB granted the applied-for connecting facilities a Certificate of Public Convenience and Necessity. NLNG claimed that TransCanada will seek to delay or frustrate the project, but provided no evidence to support this claim. Should TransCanada seek to frustrate the Project for the benefit of itself, Union, or EGDI, the Board would consider such circumstances on a future application with supporting evidence.

Finally, NLNG asserted that "granting the orders would satisfy conditions precedent to obtain project financing." This, in and of itself, does not constitute justification for granting the Orders. It would be unfair to TransCanada, its shippers and potential shippers to grant the requested Orders for NLNG to satisfy financing conditions – the details of which NLNG did not provide. NLNG has not provided any compelling evidence in terms of why its unique financing circumstances warrant the relief requested. In any event, the Board agrees with the submission of TransCanada that to require it to build interconnection facilities without a financial backstop in place would place an undue burden on the company, and place risk on the Mainline and its shippers.

No party requested further process, and the Board finds no further process is necessary to address the Application. For all of the above reasons, the Board has determined that it will not exercise its discretion to grant the Orders requested by NLNG.

The Board expects that TransCanada will uphold its commitment to advance discussions with NLNG as it would normally do with any other party seeking service requiring additional facilities on the Mainline in accordance with its tariff.

Direction to Serve Notice

The Board directs TransCanada to serve a copy of this letter on all TransCanada shippers, all members of its Tolls Task Force, and other interested persons.

P. Davies
Presiding Member

S. Parrish
Member

S. Kelly
Member

December 2018
Calgary, Alberta

TAB 7 – OEB Decision and Order dated November 18, 2018, EB-2018-0248

Ontario Energy Board
Commission de l’énergie de l’Ontario

DECISION AND ORDER

EB-2018-0248

NIPIGON LNG CORPORATION
ON BEHALF OF NIPIGON LNG LP

Application for a certificate of public convenience and necessity to construct works to supply natural gas in the unincorporated Township of Ledger

By Delegation, before: Pascale Duguay

November 22, 2018

INTRODUCTION AND SUMMARY

This Decision and Order grants Nipigon LNG Corporation on behalf of Nipigon LNG LP (Nipigon LNG) a certificate of public convenience and necessity to construct works to supply Nipigon LNG's liquefied natural gas plant (LNG plant) in the unincorporated Township of Ledger.

THE PROCESS

Nipigon LNG filed an application with the Ontario Energy Board (OEB) on August 9, 2018 under section 8 of the *Municipal Franchises Act, 1990*. The application was for an order of the OEB approving a certificate of public convenience and necessity to construct works to supply natural gas in the unincorporated Township of Ledger.

The OEB held a written hearing. A Notice of Hearing was published in the local newspaper on October 16, 2018. The Ministry of Natural Resources and the Ministry of Municipal Affairs, which serve as authorities for public lands and for areas with ministerial zoning orders within unincorporated townships, such as the unincorporated Township of Ledger, were served with a copy of the application and Notice of Hearing. Union Gas Limited (Union Gas) and TransCanada PipeLines Limited (TransCanada) applied and were awarded intervenor status.

On October 31, 2018, the OEB issued Procedural Order No. 1, which established dates for the filing of interrogatories, responses to interrogatories and written submissions.

BACKGROUND

Nipigon LNG is a corporation incorporated under the laws of the Province of Ontario, with its head office in the City of Vaughan. Nipigon LNG was created as a special purpose entity for the sole purpose of conducting the business and affairs associated with the Nipigon LNG project (the LNG Project).

As part of the LNG Project, Nipigon LNG expects to liquefy natural gas obtained from TransCanada's Mainline. The LNG would then be transported by truck from the LNG plant to LNG depots at industrial locations where it would then be converted to natural gas on the customer's property.

The LNG Project was approved for funding by the Ontario Ministry of Infrastructure under the Natural Gas Grant Program (NGGP). On October 3, 2018, Nipigon LNG filed a letter from the Ministry of Infrastructure (MOI) confirming that the Ontario government would continue to honour the Transfer Payment Agreement related to the LNG Project, despite the fact that the government has now introduced Bill 32, the proposed *Access to Natural Gas Act, 2018*, which if passed, will enable the creation of a new Natural Gas Expansion Support Program.

THE APPLICATION

As part of the LNG Project, Nipigon LNG is proposing to build and operate an LNG plant in the unincorporated Township of Ledger. Nipigon LNG is also proposing to construct an approximately 500-metre, 8-inch diameter pipeline (connecting pipeline) for the sole purpose of obtaining gas from, and connecting the LNG plant, to the nearby TransCanada Mainline. Nipigon LNG stated that the connecting pipeline will not allow for the supply of natural gas for local distribution to any existing buildings or structures within the Township of Ledger. Nipigon LNG applied for a certificate under section 8 of the *Municipal Franchises Act, 1990* to be able to construct the connecting pipeline, and requested a certificate limited to the whole of Lot 11 and the south half of Lot 12 in Concession 4 in the unincorporated Township of Ledger. Nipigon LNG stated that the Connecting Pipeline will be mostly located within its property, aside from traversing 50 metres of Crown land between the TransCanada right-of-way and Nipigon LNG's property boundary. Constructing the Connecting Pipeline will cost $200,000. As such, Nipigon LNG submitted that the Connecting Pipeline does not require leave to construct pursuant to section 90(1) of the *Ontario Energy Board Act, 1998* (the OEB Act).

Nipigon LNG submitted that the proposed connecting pipeline is not a bypass of another utility's existing franchise rights, as no other entities have applied for or been granted a certificate, conditional or otherwise, to serve the area. In its interrogatory response, Nipigon LNG cited Union Gas' letter to the National Energy Board dated October 24, 2018, where Union Gas confirmed that it currently does not hold any certificate rights within the unincorporated Township of Ledger.

Union Gas submitted that the proposed certificate should not be considered a stand-alone administrative item, but rather as part of a broader project to provide LNG to various communities in northwestern Ontario (i.e. the LNG Project). Union Gas noted that Nipigon LNG's statement regarding the provision of LNG services in Ontario as a competitive business was based in part on the OEB's decision in the proceeding regarding Union Gas' proposed liquefaction service at Union Gas' Hagar facility[1]. Union Gas argued that this decision only indicated that there was sufficient competition to protect the public interest specifically for Union Gas' proposed liquefaction service at Hagar. Union Gas stated that regarding the competition for expansion of gas service to new communities, it expected the OEB to issue a competition letter inviting submissions from those interested in serving these communities. Union Gas also argued that there was insufficient information on the record of this proceeding to make a determination on the public interest aspect of this application.

OEB staff submitted that it had no concerns regarding the issuance of a certificate to Nipigon LNG for the sole purpose of supplying the LNG plant, and stated its understanding that the area being requested is currently not covered by a certificate. OEB staff agreed with Nipigon LNG that given the specifications of the connecting pipeline, Nipigon LNG does not require leave to construct from the OEB. OEB staff submitted that Nipigon LNG should confirm that it will apply for the appropriate certificates and franchise agreement approvals if it intends to construct gas works and supply any customers other than the LNG plant. OEB staff also noted that rate orders under section 36 of the Ontario Energy Board Act, 1998 may be required to serve consumers with LNG, but recognized that this was out of scope for this certificate application.

Nipigon LNG's reply submission reiterated that the application currently before the OEB is for a certificate to construct a Connecting Pipeline to supply gas from the TransCanada Mainline to Nipigon LNG's proposed LNG plant, and is not for OEB approval to provide LNG to various communities in northwestern Ontario. Nipigon LNG submitted that the information requested by Union Gas is outside the scope of the application and that all of the evidence supporting the application, as well as whether or not the certificate is in the public interest, is before the OEB. Nipigon LNG also argued that the OEB's decision regarding Union Gas' proposed liquefaction service at Hagar was a generic determination to forbear from regulating the provision of LNG as opposed to only forbearing to regulate Union Gas' LNG service at the Hagar facility.

[1] EB-2014-0012

OEB FINDINGS

The purpose of the application is to obtain a certificate of public convenience and necessity for an area that will allow Nipigon LNG to construct an approximately 500 meter, 8-inch diameter pipeline to access natural from the TransCanada Mainline to feed the LNG plant. The proposed LNG plant and most of the connecting pipeline will be located on a 160-acre property that is owned by Nipigon LNG in the unincorporated Township of Ledger.

Section 8 of the MFA provides that no person shall construct any work to supply natural gas in any municipality without obtaining a certificate of public convenience and necessity from the OEB. The OEB previously determined that the fact that a pipeline connection might only be serving the party that constructed it does not negate the need for a certificate[2].

The OEB will approve the requested certificate. The certificate will cover the area limited to the south half of Lot 12 in Concession 4, and the whole of Lot 11 in Concession 4 in the unincorporated Township of Ledger. The OEB finds that it is in the public interest to approve the certificate as this pipeline is expected to provide a platform to eventually extend natural gas services where feasible to Northern, Métis and First Nation communities. While Union argued that the proposed certificate should not be considered as a stand-alone but rather as part of a broader project to provide LNG to various communities in northwestern Ontario, the OEB notes that these matters are outside the scope of the application currently before it. The OEB also notes that other approvals will be required as the project evolves to further extend the availability of natural gas to unserved communities. Union Gas can bring any relevant matters at that time. The need for further OEB approvals was recognized by Nipigon LNG in its reply submission.

Both Nipigon LNG and Union Gas brought the issue of forbearance of LNG regulation in Ontario. The OEB will not opine on this matter as forbearance from the regulation of LNG is out of scope for this proceeding.

Nipigon LNG also stated that the design, installation and testing specifications of the pipeline will conform to the Canadian Standards Association Z662-15 Oil and Gas

[2] RP-2005-0022

Pipeline Systems Code and the requirements of the Ontario Regulation 210/01 under the Technical Standards and Safety Act, 2000. Nipigon LNG also retained the services of Stantec Consulting Limited to prepare an environmental screening report for both the proposed LNG plant and the connecting pipeline. A review of the potential impacts of the project was provided. Nipigon LNG stated that based on identified potential impacts, mitigation measures were developed to minimize their effects. Nipigon LNG also stated that all provincial and local agency requirements, including permits and licences will be obtained where necessary.

IT IS ORDERED THAT:

1. A certificate of public convenience and necessity, attached as Schedule A to this Decision and Order, is granted to Nipigon LNG Corporation on behalf of Nipigon LNG LP to construct works or supply gas in the unincorporatedTownship of Ledger, limited to the south half of Lot 12 in Concession 4, and the whole of Lot 11 in Concession 4. A map of the area granted within the unincorporatedTownship of Ledger is attached as Schedule B.

2. Nipigon LNG Corporation shall pay the OEB’s costs incidental to this proceeding upon receipt of the OEB’s invoice.

DATED at Toronto, November 22, 2018

ONTARIO ENERGY BOARD

Original signed by

Pascale Duguay
Manager, Application Policy and Climate Change

SCHEDULE A

EB-2018-0248

DATED: November 22, 2018

Certificate of Public Convenience and Necessity

EB-2018-0248

Certificate of Public Convenience and Necessity

The Ontario Energy Board grants

Nipigon LNG Corporation on behalf of Nipigon LNG LP

approval under section 8 of the *Municipal Franchises Act,* R.S.O. 1990, c. M.55, as amended, to construct works to supply gas in the

Unincorporated Township of Ledger

limited to the south half of Lot 12, Concession 4, and the whole of Lot 11 in Concession 4, as outlined in the map attached to this Decision and Order as Schedule B.

DATED at Toronto, November 22, 2018

ONTARIO ENERGY BOARD

Pascale Duguay
Manager, Application Policy and Climate Change

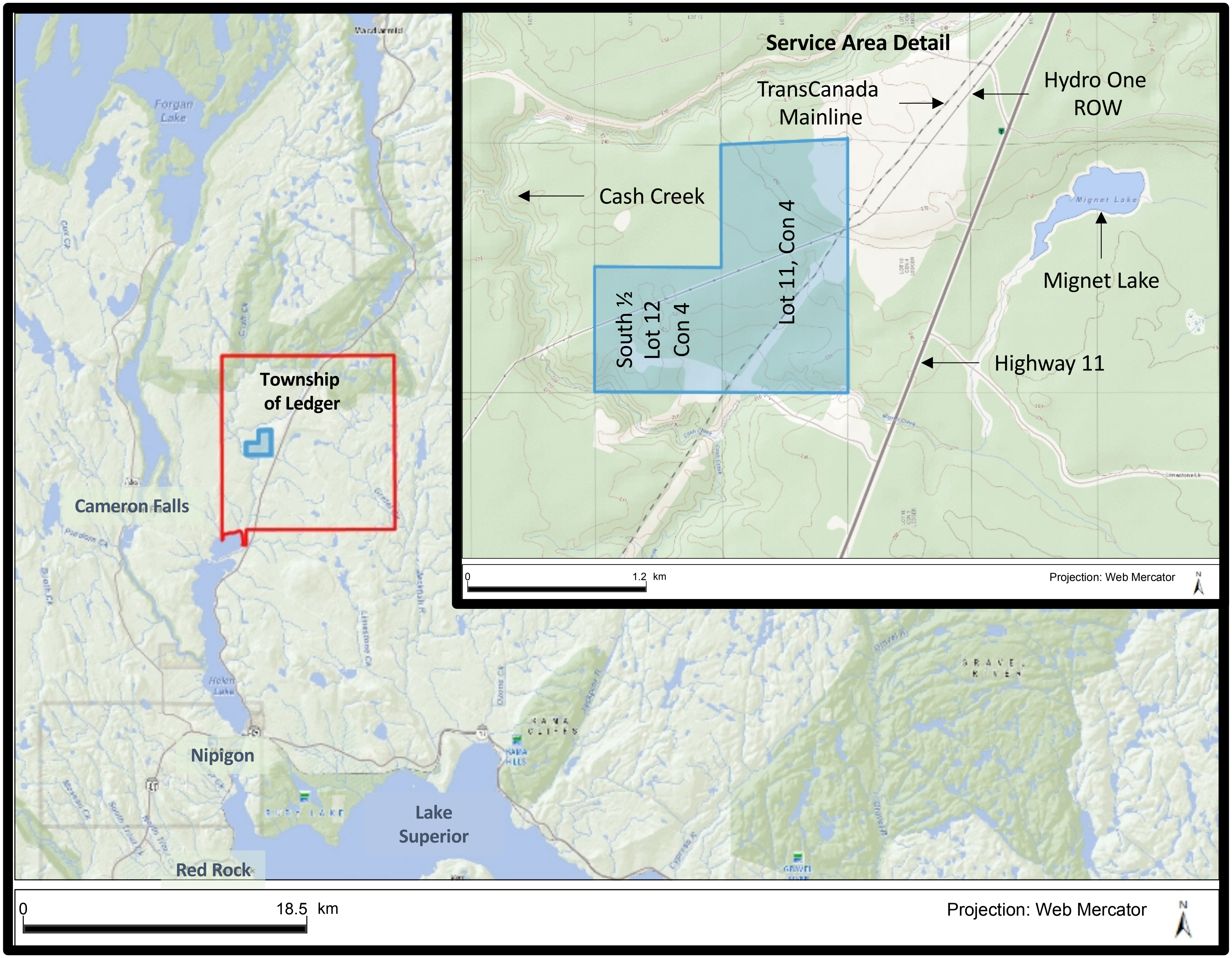
SCHEDULE B

EB-2018-0248

DATED: November 22, 2018

Map of the Service Area Granted to Nipigon LNG Corporation on behalf of Nipigon LNG LP in the Unincorporated Township of Ledger

Township of Ledger



TAB 8 - Certarus Ltd. Press Release, May 23, 2019

CERTARUS

CERTARUS LTD. ANNOUNCES STRATEGIC ALLIANCE AND COMMERCIAL INVESTMENT AGREEMENT WITH ENBRIDGE INC. FOR THE EXPANSION OF NATURAL GAS SUPPLY TO REMOTE LOCATIONS IN NORTHERN ONTARIO

TORONTO, ONTARIO (May 23rd, 2019) Certarus Ltd. ("Certarus" or the "Corporation") is pleased to announce that it has entered into a definitive agreement with Union Energy Solutions Ltd., a wholly owned subsidiary of Enbridge Inc., collectively ("Enbridge"), enabling a strategic alliance and commercial investment by Enbridge into Certarus' compressed natural gas (CNG) infrastructure platform to service the northern Ontario industrial sectors.

Certarus expects this strategic alliance will further advance its bulk CNG platform to key regions within Northern Ontario that are currently not serviced by natural gas pipelines. Certarus has developed a North American-wide bulk CNG platform to bring cost effective, environmentally preferred, natural gas safely and reliably to end users. Certarus' first terminal, located in Timmins, Ontario, is currently supplying large scale mining operations in the region. Certarus proactively built out capacity to displace over 500,000 liters of fuel per day with additional availability to expand.

Through this agreement, Certarus will expand its CNG service offering into additional projects in mining, forestry, and industrial activity currently running on diesel, bunker oil or propane. Supplying natural gas directly to industrial and commercial end-users, will provide a reliable supply of clean, cost effective energy to help support government mandates to promote cleaner-burning fuels.

"We see the increased adoption of CNG as an opportunity to displace diesel, propane and bunker oil to promote cost savings and reduce environmental impacts. Certarus operates the largest bulk CNG trailer fleet in North America and has built over 18 large-scale bulk CNG compression hubs across North America. We serve customers in all major industries across North America and are increasingly supporting customers in Northern Ontario's key industries that can benefit from the Certarus mobile pipeline." said Nathan Ough, Vice President of Certarus.

"Access to a reliable and economic energy choice is a game changer for northern Ontario," said Cynthia Hansen, President of Utility and Power Operations, Enbridge Inc. "Through CNG, large businesses can significantly lower their energy costs, be more competitive and create local jobs."

Outside of the Corporation's first terminal in Timmins, Ontario, Certarus is constructing additional CNG terminals in Red Rock (Thunder Bay Region), Ontario during Q2 2019 and in southern Ontario during Q1 2020.

ABOUT CERTARUS

Certarus Ltd is the North American market leader in providing a fully integrated bulk compressed natural gas (CNG) solution. The primary business is the creation of a "Virtual Natural Gas Pipeline" through the compression, transportation and integration of CNG for the utility, energy services, mining, forestry, agricultural and industrial sectors.

For more information, please visit www.certarus.com

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FORWARD-LOOKING STATEMENTS

Certain information contained in this document constitutes forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond the Corporation's control including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, environmental risks, competition from other industry participants, the lack of availability of qualified service providers, personnel or management and ability to access sufficient capital from internal and external sources, the inability to obtain required consents, permits or approvals and the risk that actual results will vary from the results forecasted and such variations may be material. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. The Corporation's actual results, performance or achievement could differ materially from those expressed in or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits the Corporation will derive therefrom.

The forward-looking statements contained in this document are made as of the date hereof. Certarus disclaims any intention and assumes no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law. Additionally, Certarus undertakes no obligation to comment on the expectations of, or statements made by, third parties in respect of the matters discussed above.