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 order 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.

Corporation of the Town of Marathon (“Marathon”)

Argument-in-Chief

December 11, 2019

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I. GLOSSARY

The following terms are defined in these submissions:

(a) **Anwaatin**: Anwaatin Inc.

(b) **Anwaatin First Nations**: The three First Nations communities that Anwaatin directly represents, consisting of Aroland First Nation, Animbiigoo Zaagi'igan Anishinaabek Nation, and Ginoogaming First Nation.

(c) **Applicants**: The Corporation of the Town of Marathon, on its own behalf and as a representative of the Township of Manitouwadge, The Township of Schreiber, the Township of Terrace Bay and the Municipality of Wawa.

(d) **Application**: The application in the matter (EB-2018-0329), dated and filed by the Municipalities to the Board on August 15, 2019.

(e) **Board**: the Ontario Energy Board.

(f) **Certarus**: Certarus Ltd.

(g) **CNG**: Compressed natural gas.

(h) **CPCN** or **Certificate**: Certificate of Public Convenience and Necessity.

(i) **Corporation**: The Corporation of the Town of Marathon.

(j) **Distribution System**: In this Project, approximately 116.5 kilometres ("**km**") of low pressure MDPE (medium-density polyethylene) natural gas pipeline and associated facilities within the Municipalities.

(k) **Elenchus**: Elenchus Research Associates Inc.

(l) **Environmental Guidelines**: The Board's *Environmental Guidelines for Hydrocarbon Pipelines and Facilities in Ontario*, 7th Edition (2016).

(m) **Enbridge Gas**: Enbridge Gas Distribution Inc.

(n) **EPP**: Environmental Protection Plan.

(o) **ER** or **Environmental Report**: Environmental report prepared by Stantec Consulting Inc. for each of the Municipalities and filed to the Board in this matter on August 7, 2019.

(p) **Gas Supply Plan:** The Gas Supply Plan included in the Application at Exhibit A, Tab 8, Schedule 1, Attachment 1.

(q) **Generic Proceeding on Community Expansion**: The Generic Proceeding on Community Expansion (Natural Gas) bearing the file number EB-2016-0004.

(r) **Innovative**: Innovative Research, which carried out the design and survey of the residents of the Municipalities in connection with the Application.

(s) **IR**: Interrogatory.

(t) **IRR**: Response to interrogatory.

(u) **KPI**: Key performance indicators.

(v) **LDC**: Local distribution company.

(w) **Ledger Facilities**: The interconnection facilities and delivery point on the TC Energy Mainline in the Township of Ledger.

(x) **LNG**: Liquefied natural gas.

(y) **LNG Depots** or **LNG Storage Depots**: The LNG storage and regasification depots to be built and operated in each of the Municipalities.

(z) **LNG Services Agreement** or **Contract**: The LNG services agreement included in the Application at Exhibit A, Tab 13, Schedule 1, Attachment 5.

(aa) **LTC**: Leave to construct.

(bb) **Marathon:** The Town of Marathon.

(cc) **MECP**: Ministry of Environment, Conservation and Parks.

(dd) **MEDC**: Marathon Economic Development Corporation.

(ee) **MFA**: *Municipal Franchises Act*, RSO 1990, c M.55.

(ff) **Municipal Franchise Agreement**: An agreement that will be entered into by each of the Municipalities with the Utility, and which will grant the Utility the right to construct and operate the Distribution System in that Municipality subject to the terms and conditions in the Agreement, in respect of the construction and operation of the Distribution System.

(gg) **Municipalities** or the **North Shore Municipalities**: The Town of Marathon, the Township of Manitouwadge, The Township of Schreiber, the Township of Terrace Bay and the Municipality of Wawa.

(hh) **Nipigon LNG**: Nipigon LNG LP.

(ii) **NOHFC**: Northern Ontario Heritage Fund Corporation.

(jj) **NOHFC Strategic Economic Infrastructure Program**: The program that is run by NOHFC, which helps regions and communities advance economic development opportunities and supports investments through strategic infrastructure.

(kk) **North Shore Project** or the **Project**: The project which is the subject of the Corporation's Application in the within matter (EB-2018-0329), involving the construction and operation of local gas delivery works in each Municipality, including the distribution mains, service pipes and meters.

(ll) **Northeast** or **Northeast Midstream**: Northeast Midstream LP.

(mm) **OEB Act**: *Ontario Energy Board Act, 1998*, SO 1998, c 15, Sched B.

(nn) **OEB Staff or Board Staff**: Ontario Energy Board Staff.

(oo) **OEB's Framework for the Assessment of Distributor Gas Supply Plans** or **Gas Supply Framework**: As set out in EB-2017-0129.

(pp) **OPCC**: Ontario Pipeline Coordinating Committee.

(qq) **Pre-Approval Guidelines**: The Board's *Filing Guidelines for Pre-Approval of Long-term Natural Gas Supply and/or Upstream Transportation Contracts* dated April 23, 2009.

(rr) **SEC**: School Energy Coalition.

(ss) **Stage 2 AA**: Stage 2 Archaeological Assessment.

(tt) **Stantec**: Stantec Consulting Inc.

(uu) **TC**: TransCanada.

(vv) **TCPL**: TC Energy Canadian Mainline.

(ww) **Union**: Union Gas Limited.

(xx) **Utility**: The proposed local gas distributor for the distribution of natural gas within the Municipalities.

(yy) **VECC**: Vulnerable Energy Consumers Coalition.

II. INTRODUCTION

1. The Corporation of the Town of Marathon ("**Corporation**"), 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 an 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**"). The Corporation makes this submission in support of the Application.

2. This submission is in four parts. First, it describes the approvals and orders that are being sought and provides the context for the requests for a conditional order granting leave to construct the Project and pre-approval of a Liquefied Natural Gas ("**LNG**") Services Agreement (the "**LNG Services Agreement**"). Second, it summarizes the evidence in support of the request for a leave to construct order and, in particular, the evidence with respect to Project need and feasibility, proposed facilities and alternatives and environmental, land and indigenous consultation matters. Third, it presents the case for pre-approval of the cost consequences of the LNG Services Agreement. Fourth and finally, this submission discusses the certificate and municipal franchise approvals that are sought.

III. RELIEF SOUGHT

3. A local gas distribution company (the "**Utility**") owned by the Municipalities will construct, own and operate the proposed natural gas distribution system. The Utility will be directly or indirectly owned, in equal shares, by the Municipalities. Prior to the formation of the Utility, the Municipalities have appointed the corporation as their representative for the purpose of the Application and Marathon Economic Development Corporation ("**MEDC**"), a wholly-owned subsidiary, as their agent for the purpose of developing the Project.

The Application requests the following orders,

(i) an order under s. 90 of the *Ontario Energy Board Act, 1998* ("**OEB Act**"), granting leave to construct ("**LTC**") approximately 116.5 kilometres ("**km**") of low pressure MDPE (medium-density polyethylene) natural gas pipeline and associated facilities (together, the "**Distribution System**");

(ii) an order or orders under s. 8 of the *Municipal Franchises Act*, granting Certificates of Public Convenience and Necessity ("**CPCN**" or "**Certificate**") that authorize the construction of the Distribution System in each of the five Municipalities;

(iii) an order or orders under s. 97 of the OEB Act, approving the form of Easement Agreement and form of Working Area Agreement that will be offered, by the Utility, to landowners from whom permanent or temporary land rights may be required;

(iv) an order or orders under s. 36 of the OEB Act, 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 LP ("**Nipigon LNG**") and the Utility;

(v) an order under s. 9 of the *Municipal Franchises Act*, approving the terms and conditions of an agreement (the "**Municipal Franchise Agreement**") that will be entered into by each of the Municipalities with the Utility, and which will grant the Utility the right to construct and operate the Distribution System in that Municipality subject to the terms and conditions in the Agreement, in respect of the construction and operation of the Distribution System; and

(vi) an order or orders under s. 9 of the Municipal Franchises Act, directing and declaring that the assent of the municipal electors of each Municipality to that Municipality's by-law granting the Utility the right to construct and operate the Distribution System, is not necessary.

4. While the Application has been made by the Corporation on its own behalf and on behalf of the other four Municipalities, the approvals and orders listed in paragraph 3(i), (ii), (iii) and (iv) (i.e., LTC, Certificates, approval of easement agreements and pre-approval of LNG Services Agreement) will be required by the Utility and, accordingly, should be issued to MEDC, as the proxy for the Utility. Immediately after the Utility is constituted and fully organised, the Corporation on behalf of MEDC, will make an application to the Board under s. 18(1) of the OEB Act, for leave to transfer these approvals and orders to the Utility.

5. The orders listed in paragraphs 3(v) and (vi) are required by each of the Municipalities in connection with the Municipal Franchise Agreement. The approval described in paragraph 3(v) is an approval of a form of contract and, thus, need not be issued to any specific entity. The approval listed in paragraph 3(vi) is required by each Municipality.

Request for conditional LTC approval

6. The Application, including the request for an LTC order, has been brought prior to the Utility being constituted and fully organised. This is because the commercial and/or government-backed lenders who have indicated an interest in financing the new Utility, require a degree of regulatory certainty as a pre-condition to making a commitment. In other words, the Municipalities require the Board to issue the orders described in paragraph 3 above in order to secure financing for the start-up and staffing of the Utility and the transfer of project responsibilities from the Municipalities to the Utility.

7. As the Utility has not yet been fully organised, the Application does not include information with respect to the Utility (e.g., legal name, address, legal and beneficial ownership), its financial capacity (e.g., financing sources, *pro forma* financial statements, estimates of annual cash flow) and its technical ability (e.g., licence, senior leadership team and key personnel, organizational chart, construction, operating and maintenance procedures, etc.).[1] While this information is not typically included in leave to construct applications brought by existing gas distributors in Ontario, the Municipalities recognize that the Board will wish to test the financial and technical capacity of the Utility because it is a new entrant to the Ontario natural gas market. This is why the Municipalities are asking the Board to issue an LTC order now, accepting the Corporation's evidence with respect to Project need and feasibility, the proposed facilities and environmental, land and consultation matters, but subject to a condition that requires the Utility to file, at a later date, for Board review and approval, information regarding the Utility's technical and financial capacity.

8. By conditionally approving the LTC, the OEB will facilitate the development of the proposed new Distribution System, thereby ensuring that residential and business customers in the Municipalities will have timely access to new lower cost energy, an objective that is consistent with Ontario's energy and economic policies. At the same time, the OEB will preserve its ability to satisfy itself that the Utility has the technical ability and financial capacity required to construct, own and operate a gas distribution system.

9. The Application included a proposed Project Schedule[2] which anticipated receipt of a conditional LTC order by December 2019 and an unconditional LTC order by March 2020. This schedule was optimistic having regard to the amount of time it would take to prosecute the Application, secure

[1] Application, Exhibit A, Tab 3, Schedule 1, pages 5-6 for a complete list of information respecting financial capacity and technical ability.

[2] Application, Exhibit A, Tab 7, Schedule 3.

financing, establish the Utility and prepare and file the technical and financial capacity information required to meet the LTC condition proposed in the Application.

10. Nevertheless, the Municipalities remain committed to pursuing an aggressive timetable and expect the Utility will be able to file technical and financial capacity information with the Board shortly after a decision in this Application has been issued, financing secured, employees hired and external consultants retained. To this end, the Municipalities are already engaged in preliminary discussions with commercial and government-backed lenders and will take steps to finalize financing after receipt and consideration of the Board's decision on the Application. As discussed in the Application, many of the experts that assisted the Municipalities in the preparation of the studies and assessments that underpin the Application, are expected to be employed or retained by the Utility to move the Project forward. The Municipalities expect that because the Utility will not be starting "from scratch", it will be possible to expedite the technical and financial capacity filing.

Request for pre-approval of cost consequences of LNG Services Agreement

11. The Application requests that the Board pre-approve, pursuant to s. 36 of the OEB Act and the Board's Filing Guidelines for Pre-Approval of Long Term Natural Gas Supply and/or Upstream Transportation Contracts (the "**Pre-Approval Guidelines**"), the cost consequences of the LNG Services Agreement to be entered into by the Utility and Nipigon LNG.

12. Under the LNG Services Agreement, the Utility will purchase four categories of gas transportation and storage services from Nipigon LNG: (i) the receipt of natural gas purchased by the Utility and delivered to the interconnect between the TC Energy Canadian Mainline ("**TCPL Mainline**") and facilities owned by Nipigon LNG in the Township of Ledger; (ii) the liquefaction and storage of the Utility's natural gas at Nipigon LNG's liquefaction facility; (iii) the truck transport of LNG from Nipigon LNG's liquefaction facilities to storage and regasification facilities (the "**LNG Depots**") to be constructed, owned and operated by Nipigon LNG in each of the five Municipalities; and (iii) the regasification of the LNG and re-delivery of natural gas to the Utility's distribution system. The LNG Services Agreement is discussed in detail below at paragraphs 76-77.

13. The Corporation seeks pre-approval of the cost consequences of the LNG Services Agreement in order to: (i) provide the Utility and its investors with the necessary assurance that the costs associated with the proposed agreement will be eligible for recovery from the Utility's customers; and (ii) provide Nipigon LNG with the assurance it requires to make the financial commitment to construct the proposed LNG storage and regasification facilities in each Municipality. Without pre-

approval of the cost consequences of the proposed agreement, the Utility's investors would not commit the capital to finance the Utility and, in turn, Nipigon LNG could not commit to build and operate the storage and regasification facilities.

IV. LEAVE TO CONSTRUCT

(a) Description of Project Facilities

14. The Distribution System will comprise discrete pipeline systems in each of the five Municipalities, unconnected with each other, for a total combined length of approximately 116.5 km, as follows:[3]

Community	Approximate Length (km)				Material
	2" Pipe	4" Pipe	6" Pipe	Total Pipe	
Manitouwadge	17	3.5	-	20.5	MDPE NPS 2 & 4
Marathon	30	-	5	35	MDPE NPS 2 & 6
Schreiber	11.5	4.5	-	16	MDPE NPS 2 & 4
Terrace Bay	13	5	-	18	MDPE NPS 2 & 4
Wawa	20	7	-	27	MDPE NPS 2 & 4

15. The distribution mains will be installed, for the most part, within previously disturbed municipal rights-of-way, as described below:

- **Manitouwadge**: Low-pressure NPS 4 MDPE will extend north, along Station Road, turn west onto Ohsweken Road, turn south onto Adjala Avenue and then southwest to Graham Drive.

- **Marathon**: Low-pressure NPS 6 MDPE will extend along Peninsula Road and Stevens Avenue.

- **Schreiber**: Low-pressure NPS 4 MDPE will commence at the TransCanada Highway, turn onto Simon Street and then east to Langworthy Street, turning south onto Peary Street and then south, until the end of Winnipeg Street.

- **Terrace Bay**: Low-pressure NPS 4 MDPE will extend along the TransCanada Highway and Mill Road.

[3] Application, Exhibit A, Tab 5, Schedule 1, page 2.

- **Wawa**: Low-pressure NPS 4 MDPE will extend north, along the TransCanada Highway and Route 101 and then turn west, onto Government Road.[4]

16. The ancillary facilities comprising the Distribution System will include: connections to each of the five LNG Storage Depots in each Municipality; a supervisory control and data acquisition ("**SCADA**") system that will continuously monitor the operating pressure of the discrete systems in each Municipality; a meter and pressure regulator at each customer connection; and sectional valves that serve to isolate specific pipeline sections in order to accommodate regular maintenance and emergency repairs.[5]

17. The Distribution System will be designed and constructed in accordance with all applicable standards, specifications and requirements, including those specified in CSA Z662-15, CSA Z247-15 and the *Technical Standards and Safety Act, 2001* and the regulations made thereunder.[6]

(b) **Project Need**

18. There is a clear public need for access to natural gas in the Municipalities. At present, there is no natural gas supply or distribution within any of the Municipalities and no other entity has indicated a desire to serve the area.[7] This means the Municipalities' constituents must rely on propane, fuel oil, wood and electricity, all of which are more expensive and less reliable sources of energy, compared with natural gas.[8]

19. With many elderly residents and an ageing population, a large number of residents in the Municipalities are on fixed incomes and reducing energy costs in the region would be especially beneficial to these residents.[9] Additionally, there are plans for assisted living facilities in the Municipalities.[10] These facilities represent new construction opportunities in which residents would benefit from access to natural gas.[11]

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[4] *Ibid*.
[5] *Supra* note 3 at page 1.
[6] *Technical Standards and Safety Act, 2000*, S.O. 2000, c.16.
[7] Application, Exhibit A, Tab 2, Schedule 1, page 2. See also response to Certarus Interrogatory-14(a).
[8] Application, *supra* note 7.
[9] Application, Exhibit A, Tab 4, Schedule 3, page 3.
[10] *Ibid*.
[11] *Ibid*.

20. Providing northern Ontario communities with access to less expensive and reliable sources of energy is consistent with the government of Ontario's energy and economic development policies:[12]

> There is significant demand for natural gas, particularly among families and business in rural and Northern Ontario. Natural gas is the most common heating source in Ontario and is more affordable than other sources, such as electricity, oil or propane. The government is committed to meeting this demand and is taking action to expand access to natural gas across Ontario…. Expanding natural gas would make Ontario communities more attractive for job creation and new business growth, and send a clear message that Ontario is open for business.[13]

(c) **Project Benefits**

21. The Project is a community-led and community-endorsed initiative.[14] Access to natural gas will benefit all sectors in the form of lower energy costs. The "knock on" effects will be revitalized local economies, a contribution to Ontario's gross domestic product and a reduction in greenhouse gases.

22. Residential customers will pay less for energy, reducing their overall cost of living. The following table sets out total annual regional savings attributable to conversions to natural gas in the residential sector, assuming 3,111 residential attachments by the end of the tenth year of operation.[15]

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[12] Application, *supra* note 7 at page 3.

[13] Ontario, Government of. (2018). Fall Statement 2018. November 2018. https://www.fin.gov.on.ca/fallstatement/2019/chapter-1b.html#section-6

[14] Application, *supra* note 7 at page 4.

[15] *Supra* note 9.

Fuel	% of Residents Currently Using Each Fuel	% Responded Definitely or Likely to Convert	% of Total Customers to Convert from Each Fuel	Estimated Conversions from Each Fuel	Annual Savings with NG	Total Annual Savings
Propane	12.1%	65%	16.09%	501	$ 1,241	$ 621,230
Fuel Oil	30.2%	41%	25.38%	790	$ 1,533	$ 1,210,191
Electricity	47.0%	54%	52.09%	1,620	$ 1,498	$ 2,428,117
Other	10.8%	29%	6.43%	200	$ 1,463*	$ 292,846
Total	**100%**		**100%**	**3,111**		**$ 4,552,385**
*Weighted-average annual savings for electricity, propane and fuel oil included for "Other" estimate						

23. Access to natural gas will also allow commercial institutional and industrial customers to lower their operating costs. Commercial customers are expected to save 40 percent by converting from propane, 45 percent by converting from fuel oil and 60 percent by converting from electricity.[16] The relative cost difference between natural gas and electricity is more substantial for commercial and institutional customers because those customers continue to incur a variable distribution charge.[17] As shown in the table below, commercial customers in the Municipalities are expected to save $1.87 million, annually, by converting to natural gas.[18]

Fuel	Current Annual Fuel Cost of Expected Customers	% of Customers Converting from Each Fuel	Annual Cost of Equivalent Energy in Natural Gas	Annual Savings with Natural Gas
Propane	$1,506,445	44%	$903,867	$602,578
Oil	$1,232,546	33%	$677,900	$554,646
Electricity	$1,181,190	23%	$472,476	$708,714
Total	$3,920,180	100%	$2,054,243	$1,865,937

24. Institutional customers are expected to save 25 percent by converting from propane, 40 percent by converting from oil and 60 percent by converting from electricity.[19] As shown in the table below, institutional customers are forecast to save over $619,000 each year by converting to natural gas.[20]

[16] *Supra* note 9 at page 4.
[17] *Supra* note 9 at page 5.
[18] *Ibid.*
[19] *Ibid*.
[20] *Supra* note 9 at page 6.

Fuel	Current Annual Fuel Cost of Expected Customers	% of Customers Converting from Each Fuel	Annual Cost of Equivalent Energy in Natural Gas	Annual Savings with Natural Gas
Propane	$943,328	60%	$707,496	$235,832
Oil	$648,538	33%	$389,123	$259,415
Electricity	$206,353	7%	$82,541	$123,812
Total	$1,798,219	100%	$1,179,160	$619,059

25. Accounting for conversion costs, residential customers in the Municipalities can expect to spend about $21.3 million on conversion costs, in 2020 dollars, in the first 10 years.[21] This results in a total net savings of $15 million for the residents of the Municipalities in the first 10 years. The total cost of conversion in the first 40 years is expected to be $27.7 million resulting in a total net savings of $165.6 million in the first 40 years for residential customers.[22] Much of this money, which would have otherwise been spent on energy, will be saved or spent within the communities.[23] The increased economic activity of this spending will benefit businesses across the region. [24]

26. Over the first 40 years of operation, the Municipalities' commercial and institutional customers are expected to save approximately $100.6 million in their energy costs, in 2020 dollars.[25] Commercial and institutional conversion costs would vary greatly based on the current fuel use and building specifications of each customer.[26] These costs are not forecast here, but it is expected that energy cost savings would materially outweigh conversion costs.[27]

27. The table below summarizes total 10-year and 40-year projected energy savings for the Municipalities for residential and General Service customers, not including conversion costs. [28]

[21] Application, Exhibit A, Tab 9, Schedule 2, page 3.
[22] *Ibid*.
[23] *Ibid*.
[24] *Supra* note 21 at pages 1-3.
[25] *Supra* note 21 at page 4.
[26] *Ibid*.
[27] *Ibid.*
[28] *Supra* note 21 at page 5.

Year	10-Year Total Savings	40-Year Total Savings*
Residential	$36,316,146	$193,316,064
General Service	$20,401,894	$100,643,696
Total	**$56,718,040**	**$293,959,760**
*All savings are in nominal dollars using the savings expected in the first year of service		

28. It is for these reasons that the proposed Distribution System has been proposed. The benefits in the form of cost savings are significant.

(d) Forecast of Market Demand

29. The Municipalities retained Elenchus Research Associates ("**Elenchus**") to develop 25-year natural gas market demand forecasts for the Municipalities, by customer type. These forecasts were then used as the basis for facilities design and the development of distribution rate forecasts, by customer class. A table setting out the 25-year, overall market demand forecast is included in the Application at Exhibit A, Tab 4, Schedule 1, Attachment 2, p. 5 of 5.

30. Elenchus used a "grassroots" approach to develop its long-term market demand forecast by:

- developing inventories of building stock within each municipality, by building type;
- surveying customer classes (e.g., residential, commercial, institutional and industrial) to ascertain interest in converting to natural gas, based on indicative cost savings as compared to other fuels;
- developing average-use estimates, by customer type;
- aggregating demand across all customer types and municipalities and conducting a sensitivity analysis;
- assessing supply, storage and transportation options;
- developing a forecast of distribution rates, by customer type, based on survey results;
- adjusting average-use estimates for anticipated equipment efficiency improvements; and

- confirming that the delivered cost of gas was consistent with initial indicative cost assumptions.[29]

31. As a first step in the development of the market demand forecasts, Elenchus commissioned Innovative Research Group Inc. ("**Innovative**"), a national public opinion research firm, to design and execute a telephone survey of residents in the five Municipalities in order to determine the level of interest in converting to natural gas and, thus, the market demand for natural gas line connections.[30] Elenchus provided Innovative with information related to indicative costs to supply natural gas, the upfront costs to convert to natural gas in the area and the cost of natural gas compared to current fuel costs.[31] Elenchus also contacted local heating, ventilating and air conditioning contractors to seek their input on the indicative cost to convert various existing heating and water-heating systems to natural gas.[32] This information was then shared with Innovative.[33]

32. Innovative's report is included in the Application at Exhibit A, Tab 4, Schedule 7, Attachment 1. The specific results of the Innovative study are summarized and discussed in the Application at Exhibit A, Tab 8, Schedule 1, Attachment 1, pp. 8-12.

33. The Innovative report included the following key findings:

- most residents of the Municipalities are aware of the proposal to bring natural gas to their communities and are favourably predisposed towards the use of natural gas;

- 49 percent of those surveyed said they would convert their heating system to natural gas, 51 percent were likely to convert their water heaters and 38 percent were likely to convert both;

- the response was not the same for all Municipalities; residents are more likely to convert to natural gas in Municipalities where awareness of the plan is highest;

- cost is a significant factor:

[29] Application, Exhibit A, Tab 8, Schedule 1, Attachment 1, page 10.
[30] *Ibid* at page 12.
[31] *Ibid*.
[32] *Ibid*.
[33] *Ibid*.

- it is a primary reason for not converting and the main deciding factor for those who are not sure;
- a lower conversion cost often results in a greater likelihood to convert, but it is not a linear relationship as potential savings also have an impact; and
- a grant to help with the conversion cost increases the likelihood of conversion; and

- perception of natural gas matters; those who view natural gas favourably are significantly more likely to consider converting.[34]

34. Elenchus used the results of Innovative's residents' survey to develop an 11-year natural gas market demand forecast for the residential sector in each of the Municipalities, based on an estimate of average use per customer (see Exhibit A, Tab 8, Schedule 1, Attachment 1, pp. 13-15 and Appendix 1 for a description of the derivation of this estimate). An expanded 25-year residential demand forecast is included in the Application at Exhibit A, Tab 4, Schedule 1, Attachment 2, page 1 of 5.

35. Elenchus, itself, surveyed potential commercial customers in the five Municipalities. Among the potential commercial customers contacted, there was significant interest in converting to natural gas, subject to being offered competitive natural gas rates at the time of conversion and subject to the costs of conversion.[35] <u>Overall, 60 percent of survey respondents indicated that they were willing to consider switching</u>.[36] As with residential customers, some potential commercial customers were "undecided" as to whether they would convert to gas or not.[37] Elenchus believes that once undecided customers have had the opportunity to fully evaluate the benefits of converting to natural gas, the conversion rate will increase from 60 percent to 65 percent.[38] Elenchus' commercial sector findings were used to develop a 25-year overall commercial market demand forecast for natural gas in each of the Municipalities.[39] This forecast is included in the Application at Exhibit A, Tab 4, Schedule 1, Attachment 2, page 2 of 5.

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[34] *Supra* note 29 at page 13.
[35] *Supra* note 29 at page 20.
[36] *Ibid*.
[37] *Ibid*.
[38] *Ibid*.
[39] Application, Exhibit A, Tab 4, Schedule 1, page 14.

36. Elenchus also conducted a phone survey of potential institutional customers (i.e., municipal, school boards and health care institutions and agencies). Survey responses were received from 48 of 55 potential institutional customers.[40] Among those surveyed, there was widespread awareness of the Project. <u>Over 96 percent of respondents indicated a willingness to consider converting to natural gas</u>.[41] The institutional survey results were used to develop a 25-year institutional market demand forecast for natural gas in each Municipality.[42] This forecast is included in the Application at Exhibit A, Tab 4, Schedule 1, Attachment 2, page 3 of 5.

37. Elenchus' industrial market demand forecast (Exhibit A, Tab 4, Schedule 1, Attachment 2, page 4 of 5) comprises a 25-year annual consumption forecast of one industrial customer who uses No. 6 residual fuel and has expressed interest to replace some of its current fuel use with natural gas, on an interruptible basis pursuant to a demand response program. Under this arrangement, the industrial customer would increase its use of natural gas and reduce its consumption of No. 6 residual fuel oil when the contracted LNG capacity is not required by the Utility's firm customers.[43] Conversely, when the firm demand of the Utility's residential and General Service customers increases up to the level of the contracted LNG capacity, the industrial customer would reduce its consumption of natural gas and increase its consumption of No. 6 residual fuel oil.[44] This arrangement benefits the industrial customer by reducing its overall energy costs and benefits the Utility and its residential and General Service customers by reducing capacity-related, pass-through costs below what they would otherwise be.

38. The aggregate market demand forecast anticipates the majority of potential customers to attach within the first few years of operation, followed by gradual increase attachments, consumption, and demand. Consumption and demand growth are somewhat offset by expected equipment efficiency improvements over time.

(e) <u>**Economic Feasibility**</u>

39. The total projected capital cost of constructing the Distribution System, including contingency, is $40.5 million, net of the Northern Ontario Heritage Fund Corporation ("**NOHFC**") grant.[45] This amount represents the cost of a full build-out to serve all potential customers in the Municipalities. The annual cost of annual capital additions, commencing in the fourth year after completion of

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[40] *Supra* note 29 at page 22.
[41] Application, Exhibit A, Tab 4, Schedule 1, page 15.
[42] *Supra* note 39 at page 15.
[43] *Supra* note 29 at page 22.
[44] *Ibid*.

construction, is estimated at $40,500 (i.e., 0.1 percent of initial asset value).[46] Projected annual operating, maintenance and administrative ("**OM&A**") costs for the first assumed year of operation (2020) are estimated at $1,425,115.[47]

40. Elenchus has developed a forecast of standalone rates for each customer class, based on an annual revenue requirements developed using its estimates of capital, OM&A and financing costs. Projected rates are levelized over the first 20 years of the Utility's operation.[48] In the first assumed year of operation (2020), the all-in residential rate, based on the assumed revenue requirement, is estimated at $19.95/GJ, comprising a delivery rate of $6.68/GJ and total pass-through costs (for upstream gas supply and transportation costs, LNG Services Agreement costs and carbon charges) of $13.27/GJ. The Small General Service (Commercial) rate is estimated at $17.63/GJ and the Large General Service Institutional rate at $17.12/GJ.

41. The proposed natural gas distribution system is a true standalone project and the proposed Utility will be a true standalone utility. Its capital and OM&A costs will not be co-mingled with those of any other gas distribution utility and will be recorded and expensed within the framework of the Utility's proposed single rate zone. The Utility's customers will pay standalone rates. There is no possibility that the Utility's customers will be subsidized by the customers of other Ontario natural gas distributors. In the circumstances, the Board's test for economic feasibility that is set out in Board Decision E.B.O.-188, is not applicable.[49]

42. In an interrogatory,[50] Board Staff asked whether the Utility proposed to implement a rate stability period, as contemplated by the Board in its decision in its Generic Proceeding on Community Expansion. Under this framework, a utility would bear attachment forecast and capital cost risks for the duration of the rate stability period.[51] In its response, the Corporation noted that the Utility, rather than the Municipalities, would be best placed to consider this issue when it seeks a final, unconditional LTC order. The Utility will have the benefit of advice and guidance from expert and experienced utility professionals who will oversee various pre-construction activities, including detailed engineering and design, field surveys, geotechnical investigations and the solicitation of

[45] Application, Exhibit A, Tab 9, Schedule 1, page 1.
[46] *Ibid* at page 2.
[47] Application, Exhibit A, Tab 9, Schedule 3, page 1.
[48] Application, Exhibit A, Tab 4, Schedule 2.
[49] The test for economic feasibility set out in Board Decision E.B.O.-134 is also not applicable because the proposed Distribution System does not include any transmission pipelines.
[50] OEB Staff Interrogatory–12.
[51] OEB Proceeding EB-2016-0004, Decision with Reasons, (November 17, 2016) at page 20.

competitive proposals from potential construction contractors.[52] Information and data resulting from this work will inform updated and refined cost forecasts. This will permit the Utility to make a prudent determination of how risk should be allocated among the Utility, its investors and lenders and its ratepayers.

43. Finally, we note that a key driver of the Board's rate stability proposal is to incent utilities, competing to secure a distribution franchise, not to overstate their forecast of customer attachments nor understate their forecasts of long-term costs, in order to increase their chance of being selected as the successful proponent. In this case, there is no competing utility and, so, there is no incentive to overstate or understate forecasts in order to be selected as a successful proponent. We note, moreover, that the Municipalities have every incentive to develop forecasts that are as accurate as possible, given the early stage of development. This is because all of the Project's forecasts, projections and estimates will be scrutinized and vetted by potential lenders in the context of obtaining preliminary financing, the next stage in the development process.

(f) **Environmental Matters**

Environmental Reports

44. The Municipalities retained Stantec Consulting Inc. ("**Stantec**") to undertake an environmental and socio-economic impact study with respect to the construction and operation of the proposed Distribution System and LNG Depots in each Municipality (the "**Environmental Study**").[53] The Environmental Study included a cumulative effects assessment and was performed in accordance with the requirements of the OEB's *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition* (2016) (the "***Environmental Guidelines***").[54] The results of the Environmental Study are set out in the five environmental reports which are incorporated, by reference, in the Application at Exhibit A, Tab 10, Schedule 1, Attachments 1a-1e (together, the "**Environmental Reports**").

45. The Environmental Reports addressed, among other things, LNG Depot siting and pipeline route evaluation and selection; public and Indigenous consultation; and physical, bio-physical, socio-economic and environmental impact identification, assessment and mitigation.[55] In this regard, the Municipalities note that while the Environmental Reports considered the impacts of the

[52] Response to OEB Staff Interrogatory-16, page 43.
[53] Application, Exhibit A, Tab 10, Schedule 1, page 1.
[54] *Ibid*.
[55] Environmental Reports, Executive Summary.

construction and operation of both the LNG Depots and the Distribution System, the scope of the Application is limited to the Distribution System.[56]

46. **Route evaluation and selection:** The overarching objective in the route evaluation and selection process was the selection of a route that presents the least potential for adverse environmental and socio-economic impacts.[57] In implementing this objective, Stantec sought to minimize route length, avoid sensitive environmental and socio-economic features wherever practicable and to utilize existing linear infrastructure.[58] Stantec's route selection process also had regard to engineering and technical feasibility and to optimizing customer supply.[59]

47. Each Environmental Report identified one preferred route and an alternative segment.[60] Stantec ultimately excluded the alternative segments as they did not allow lateral pipelines to reach as many residences and businesses as the preferred preliminary route.[61]

48. **Consultation**: In connection with the Environmental Study, Stantec undertook a consultation program that involved:

- Identifying interested parties early in the process, based on the OEB's OPCC Members List, the MECP Environmental Assessment Government Review Team Master Distribution List and the consultation experience of Stantec.[62] Indigenous communities were identified, in part, through provision of a project summary to the Ministry of Energy, Northern Development and Mines ("**MENDM**") in March 2019. MENDM then provided the Corporation and Stantec with a letter, dated May 21, 2019. This letter, among other things, delegated the procedural aspects of the duty to consult to the Municipalities and identified Indigenous communities to be consulted on the basis that they have or may have constitutionally protected Aboriginal or treaty rights that may be adversely affected by the Project. Stantec also consulted federal and provincial agencies and authorities; municipal personnel, including elected officials; local residents and businesses; special

[56] Application, *supra* note 7.
[57] *Supra* note 55, s 2.3.1 (Routing Objectives).
[58] *Ibid*.
[59] See, e.g., Environmental Reports for Terrace Bay, Manitouwadge, and Marathon.
[60] *Supra* note 55, s 2.4 (Step 2: Generate Route Options).
[61] *Supra* note 55, ss 2.4 and 2.5.
[62] *Supra* note 55, s 3.2.

interest groups; and members of the public through public consultation efforts, such as newspaper notices or public information sessions ("**Information Sessions**").[63]

- Informing and educating interested parties about the nature of the Project, potential impacts, proposed mitigation measures and how to participate in the consultation program in a clear, concise, relevant and timely manner.[64] In connection with the foregoing, Stantec arranged for the circulation of newspaper notices that described the Project, the environmental study process, provided an overview map identifying the Municipalities involved in the Project, the details for the relevant Information Sessions, and Project contact details.[65] Stantec also circulated study commencement letters to stakeholders addressing the foregoing topics.[66] Stantec's study commencement letters also requested information regarding potential areas of concern with respect to planning principles, local developments, environmental, socio-economic, archaeological, and cultural heritage concerns, and impacts on constitutionally protected Aboriginal or treaty rights and measures for mitigating those impacts.[67] A website detailing the Project was set up to provide an additional forum for interested parties to make inquiries.[68]

- Providing a forum for the identification of issues. In addition to the foregoing, Stantec organized public Information Sessions during which attendees could view information about the Project and ask questions and comment on the planning process to be followed both during the Information Sessions and by way of exit questionnaires.[69]

- Revision of the consultation program to meet the needs of those being consulted and developing a framework for ongoing communication during the construction and operation phase of the Project.[70]

- Consideration and resolution of issues resulting from consultation, whether immediate or by way of recommended mitigation and protective measures.[71] The Project team

[63] *Ibid*.
[64] *Supra* note 55, s 3.1.
[65] *Supra* note 55, s 3.3.1.
[66] *Ibid*.
[67] *Supra* note 55, s 3.3.2.
[68] *Supra* note 55, s 3.3.3.
[69] *Supra* note 55, ss 3.3.4 and 3.4.1.
[70] *Supra* note 55, s 3.1.
[71] *Supra* note 55, s. 3.1.

received input from the public, agencies, interest groups, Indigenous communities, municipal and elected officials, and other third parties. In particular, the Environmental Reports were submitted to the OPCC on August 2, 2019.[72] The Environmental Reports incorporate refinements to the Project or the recommended mitigation and protective measures based on input from the public, agencies (including OPCC), interest groups, municipal and elected officials, Indigenous communities, and other third parties.[73] The OPCC provided its comments to the Project team in October 2019. The Project team has responded, either by way of a reply or comment and/or a commitment to implement mitigation measures.

49. **Physical, bio-physical, socio-economic and environmental impacts**: The Environmental Study considered the impacts of the Project's construction, operation and maintenance activities with regard to (among other things): geological and hydrogeological features; extractive resources; soil and soil capability; natural hazards; aquatic species and habitat; natural areas and vegetation; wildlife and wildlife habitat; local residents and businesses; community services and infrastructure; local culture, tourism, and recreational facilities; local economy and employment; contaminated sites and landfills; waste management; land uses; archaeological resources; heritage resources and cultural heritage landscapes; infrastructure; and Indigenous interests.[74] The Environmental Reports then made recommendations as to mitigation and protective measures, the implementation of which measures would result no significant adverse residual impacts.[75]

50. **Cumulative effects assessment**: Potential cumulative effects were assessed in accordance with the *Environmental Guidelines* by considering other developments that may coincide with the construction and operation of the Project.[76] The Study Area boundary (both spatial and temporal) was used to assess potential effects of the Project and other developments on environmental and socio-economic features.[77] The cumulative effects assessment determined that, by providing ongoing consultation and implementing appropriate mitigation and protective measures, the

[72] *Supra* note 53.
[73] *Supra* note 55, s 3.5.
[74] *Supra* note 55, s 4.
[75] *Ibid*.
[76] *Supra* note 55. See also *supra* note 55, s 5.
[77] *Ibid*.

Project's potential cumulative effects will be of low probability and magnitude, short duration and reversible, and are therefore not anticipated to be significant.[78]

51. **Monitoring and contingency plans**: The Environmental Reports set out monitoring plans to ensure that the mitigation and protective measures set out therein are effectively implemented and to measure the impacts of activities associated with construction on environmental and socio-economic features.[79] The Environmental Reports also set out contingency plans in response to unexpected events or conditions that may occur during the construction of Project-related facilities.[80]

52. **No significant adverse impacts:** In conclusion, the Municipalities do not expect that the Project will result in any significant adverse environmental and socio-economic impacts following the implementation of appropriate mitigation and protective measures described in the Environmental Reports. Monitoring will assess if mitigation and protective measures have been effective in both the short and long term.

Environmental Protection Plan

53. The Municipalities will implement the Environmental Reports' recommended mitigation and protective measures[81], as well as the OPCC's comments received in October 2019 as noted above.[82] The implementation of these mitigation and protective measures in the EPP, along with ongoing communication and consultation and adherence to permit, regulatory and legislative requirements, is expected to minimize potential adverse residual environmental and socio-economic impacts of the Project, which are not expected to be significant.[83]

54. The EPP is expected to be completed prior to tendering the package to the construction contractors.[84] The Utility will file the EPP into evidence and circulate it to the OPCC once developed.[85]

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[78] *Ibid*.
[79] *Supra* note 55, s 6.1.
[80] *Supra* note 55, s 6.2.
[81] Set out at Appendix G of the Environmental Reports.
[82] Application, Exhibit A, Tab 7, Schedule 1, page 4.
[83] *Supra* note 55.
[84] Response to OEB Staff Interrogatory-17(a).
[85] Response to OEB Staff Interrogatory-17(b) and (c).

Environmental Conditions of Approval

55. In OEB Staff Interrogatory-48, Board Staff proposed draft Conditions of Approval whereby the Utility shall implement all the recommendations of the Environmental Report filed in the proceeding, and all the recommendations and directives identified in the OPCC review. The Municipalities confirm that they would comply, or ensure compliance, with such conditions.

(g) **Indigenous Consultation**

56. The Municipalities are committed to fostering a positive and productive relationship with all Indigenous rights-holder groups, including First Nations and Métis communities.[86] Throughout the development process, the Municipalities have engaged First Nations and Métis communities in order to: (i) build understanding about Project-related interests; (ii) ensure that applicable requirements are met; (iii) mitigate or avoid project impacts on Indigenous communities and on their traditional territories; and (iv) provide mutually beneficial Project-related opportunities, including those related to potential economic and business opportunities.[87] The Municipalities are committed to continue their engagement with First Nations and Métis communities throughout the development, construction and operational phases of the Project.

57. By a letter dated May 21, 2019 (the "**Duty to Consult Letter**") from the MENDM, the Crown delegated the procedural aspects of consultation to the Municipalities.[88] The Duty to Consult Letter recommended consulting the First Nations and Métis communities listed in the letter on the basis that they have or may have constitutionally protected Aboriginal or treaty rights that may be adversely affected by the Project.[89]

58. The Municipalities carried out community engagement with numerous Indigenous communities, including, but not limited to, the First Nation and Métis communities listed in the Duty to Consult Letter. These consultation activities included letters, emails, phone calls and face-to-face meetings with representatives of these Indigenous communities.[90] Through these engagement activities, representatives of the Municipalities provided Indigenous communities with an overview

[86] Application, Exhibit A, Tab 12, Schedule 1, page 1.
[87] *Ibid*. See response to Anwaatin Interrogatory-4(a) and (b) and OEB Staff Interrogatory-19(a). See also response to Anwaatin Interrogatory-8(a).
[88] Response to Anwaatin Interrogatory-8(a), *supra* note 87.
[89] *Ibid*.
[90] *Ibid*.

of the Project and responded to questions and concerns.[91] Descriptions of these consultation activities are included in their Environmental Reports.[92]

59. In recognition of the ongoing nature of the duty to consult and having regard to the Municipalities' broader commitment to consult on an on-going basis with stakeholders, the Project team has continued to engage with Indigenous communities, including attending meetings and conference calls, holding a webinar, providing information and soliciting and discussing input.[93] Details of these ongoing consultation efforts will be included in an Indigenous Consultation Summary Report to be filed with the Board as soon as possible.[94]

60. In light of the foregoing, the Municipalities submit that the Project team has discharged the delegated consultation obligations pursuant to the Duty to Consult Letter. The team is working with the MENDM to obtain its confirmation in this regard.[95] As noted above, the Municipalities are committed to ongoing engagement and relationship building with Indigenous communities with respect to the Project.

(h) **Land Matters**

61. The preferred route of the Distribution System in each Municipality is set out at Appendix A, Figure A1 of each of the five Environmental Reports. In each Municipality, the vast majority of the preferred route is located within existing municipal road rights-of-way.[96] Accordingly, the preferred route of the Project minimizes the number of affected private landowners and the impacts of the Project on these landowners.

62. If it is determined that private landowner easements are required, easement agreements in the form shown in the Application at Exhibit A, Tab 11, Schedule 1, Attachment 4, will be negotiated with such landowners.[97]

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[91] *Ibid*.
[92] *Ibid.*
[93] See responses to OEB Staff Interrogatory-19(a) and Anwaatin Interrogatory-4(a) and (b), and the attachments thereto.
[94] Response to OEB Staff Interrogatory-22.
[95] Response to OEB Staff Interrogatory-20.
[96] Application, Exhibit A, Tab 11, Schedule 1, page 1. See also *supra* note 82.
[97] Application, Exhibit A, Tab 11, Schedule 1, page 1. See also Marathon's response to OEB Staff Interrogatory-18(a).

63. All of the Municipalities have resolved to acquire (if necessary) the land required for the LNG Depots and then sell or lease this land to the Utility. The Utility will, in turn, sell or lease the land to Nipigon LNG.[98] Nipigon LNG will construct the LNG Depots on this land.[99] The proposed form of the Utility's Agreement of Purchase and Sale is included at Exhibit A, Tab 11, Schedule 1, Attachment 2. The proposed form of the Utility's Agreement of Lease is included at Exhibit A, Tab 11, Schedule 1, Attachment 3.

64. The Township of Terrace Bay has negotiated and signed a letter of intent with AV Terrace Bay, a private landowner, for the purposes of purchasing land on which to locate Township's LNG Depot.[100]

65. Temporary workspace rights may be required during construction. The Utility's proposed form of Working Area Agreement is included in the Application at Exhibit A, Tab 11, Schedule 1, Attachment 5.[101] In this agreement, the Utility commits to clean-up and restore areas disturbed as a result of construction to the condition that existed prior to construction.[102]

66. The Utility will provide appropriate contact information and encourage landowners to approach the Utility to discuss concerns about restoration matters.[103] Upon completion of construction, the Utility will make every effort to ensure that restoration meets applicable standards.[104] Any landowners who are not satisfied will be encouraged to contact the Utility and the Utility will respond to these landowner's concerns.[105]

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

(a) Background

67. In October 2015, the Municipalities partnered with Northeast Midstream LP ("**Northeast Midstream**"), the parent company of Nipigon LNG, to submit an application to NOHFC for funding to assess the engineering, environmental and economic feasibility of developing a regional natural gas delivery system supplied by LNG, purchased from Nipigon LNG. The monies

[98] Application, Exhibit A, Tab 11, Schedule 1, page 1.
[99] *Ibid*.
[100] Response to OEB Staff Interrogatory-23(a).
[101] Response to OEB Staff Interrogatory-18(a).
[102] *Ibid*.
[103] *Ibid*.
[104] *Ibid*.
[105] *Ibid*.

received from NOHFC facilitated the completion of the feasibility work. The resulting preliminary feasibility study, entitled "North Shore Natural Gas Distribution Plan", is included in the Application as Tab 9, Schedule 4, Attachment 1. Based on the positive results of this study, the Municipalities applied for a grant under the NOHFC Strategic Economic Infrastructure Program, which assists regions and communities in advancing economic development opportunities and which supports investment through strategic infrastructure. In March 2018, the NOHFC approved a grant of $3.45 million. This funding is currently being used to support the ongoing development of the Distribution System, including applications for the regulatory approvals required to move the Project to the next stage of development and financing.[106]

68. As discussed in more detail below, other gas supply options were ruled out early in the planning process for reasons having to do with availability and cost. A pipeline option, connecting the five Municipalities with the TCPL Mainline, was ruled out because it was too costly, relative to other supply options, principally because of the cost of drilling through Canadian shield. At the time, there were no compressed natural gas ("**CNG**") facilities operating in northern Ontario, proximate to the Municipalities; in other words, CNG was not an available option. Alternative supplies of LNG were available from Enbridge Gas Inc.'s ("**Enbridge**") Hager, Ontario facility but only on an interruptible basis and only for 167 days per year. LNG supplies from Montreal and from Minnesota were simply not cost competitive. In light of the conclusions about other potential gas supply options at the time, the Municipalities concluded that LNG supplied by Nipigon LNG, was the only available, cost effective way to supply natural gas to the proposed Distribution System.

(b) <u>The Nipigon LNG Project</u>

69. The Utility intends to enter into a long-term, firm LNG Services Agreement for the provision, by Nipigon LNG, of natural gas liquefaction, transportation, storage and LNG regasification services (together, the "**LNG Services**"). The LNG Services will be provided using facilities to be constructed, owned and operated by Nipigon LNG, namely: (i) pipeline, liquefaction and storage facilities in the Township of Ledger, located proximate to the TCPL Mainline (the "**LNG Facilities**"); and (ii) LNG storage and regasification depots, located in each of the five Municipalities on lands leased from the Municipalities (the "**LNG Depots**"). Each LNG Depot will tie into the Distribution System at a location within each Municipality.

70. The LNG Facilities are designed and engineered to have a liquefaction capacity of approximately 7,200 GJ/day of natural gas, with the potential of future expansion. The LNG Facilities will tie-in

[106] Foreword to Certarus Limited IR.

to the TCPL Mainline and be capable of accepting deliveries of natural gas, procured by customers of Nipigon LNG, upstream of the tie-in point. The TCPL Mainline tie-ins are expected to be constructed and commissioned by July 1, 2020.

71. LNG produced by the LNG Facilities will be transferred to cryogenic truck trailers, owned by Nipigon LNG, for delivery to the LNG Depots in each Municipality.[107] The conceptual design for each LNG Depot includes a receipt connection that will facilitate transfers of LNG from the cryogenic truck trailers to on-site storage tanks. From these tanks, the LNG will be piped through a series of vaporizers where the LNG is regasified and delivered into the Distribution System, at the desired distribution temperature and pressure.[108]

72. Although the LNG Depots will all perform the same basic function, each LNG Depot will be sized to accommodate the specific demand requirements of the Municipality in which it is situated. With the exception of the Municipality of Wawa, on-site storage capacity at each LNG Depot will provide a minimum of five days of peak-day gas demand. The LNG Depot located in the Municipality of Wawa will be sized to provide a minimum of seven days of peak day gas demand.

73. The expected number and size of the LNG tanks in each LNG Depot is set out in the following table. Individual tanks may be added, in phases, in order to accommodate load growth over several years.[109]

Depot Location	**No. and Size of Tanks**	**Total Storage**
Manitouwadge	2 x 20,000 gallons each	40,000 gallons (US gallons)
Marathon	3 x 20,000 gallons each	60,000 gallons
Schreiber	2 x 20,000 gallons each	40,000 gallons
Terrace Bay	1 x 90,000 gallons each; 1 x 20,000 gallons each	110,00 gallons
Wawa	3 x 20,000 gallons each	60,000 gallons

[107] Application, Exhibit A, Tab 13, Schedule 1, page 2, lines 1-10.
[108] *Ibid* at page 3, lines 14-22.
[109] *Supra* note 107 at page 4, lines 6-18.

74. In addition to the storage tanks and the vaporizers, other equipment and facilities located at each LNG Depot will include:

- truck unloading skid, including offload pumps;
- electric trim heaters;
- odorization and pressure control equipment;
- control building and truck unloading area that houses automated control computers, security systems, safety systems, telemetry and communications equipment for the LNG Depot; and
- supervisory control and data acquisition systems that allow for remote monitoring of the LNG Depots.[110]

(c) **<u>The LNG Services Agreement</u>**

75. The following terms and conditions pertain to the costs and costs consequences of the LNG Services Agreement.

- **LNG Services Fees:** The following fees are payable by the Utility, to Nipigon LNG, under the LNG Services agreement:
  - **Firm Capacity Charges** (payable regardless of the level of use of the firm capacity committed to the Utility), subject to an annual escalation of 1.5 percent. In the first assumed year under the contract, the Firm Capacity Charge would be <u>$7.03/GJ</u>, based on the daily capacity committed by Nipigon LNG to the Utility. The contract recognizes that for a brand new distribution system, demand will build over time; accordingly the volume of daily committed capacity increases over the term of the contract, as follows: <u>years 1-2</u>: 2,400 GJ; <u>year 3</u>: 2,800 GJ; <u>year 4</u>: 3,100 GJ; <u>year 5</u>: 3,200 GJ; <u>year 6</u>: 3,300 GJ; <u>year 7</u>: 3,400 GJ; <u>year 8</u>: 3,500 GJ, <u>year 9</u>: 3,600 GJ; and <u>year 10</u>: 3,700 GJ.[111] The Firm Capacity

[110] *Supra* note 107 at page 5, lines 1-17; note that this system will be constructed, owned and operated by Nipigon LNG and distinct from the SCADA system that will be constructed, owned and operated by the Municipality.

[111] Application, Exhibit A, Tab 13, Schedule 1, Attachment 5, page 36, Schedule B.

Charge is subject to reduction in the event of a failure, by Nipigon LNG, to deliver natural gas from the LNG Depots.[112]

- **Variable Charges** (payable on the volume (GJs) of LNG delivered to the Utility, by Nipigon LNG) calculated as the Utility's *pro rata* share of the cost of consumables of the LNG Facilities and payable on a pass-through basis, without mark up.[113] Such Variable Charge is estimated to escalate by 2 percent per annum.[114]

- **Transportation Charges** for truck transportation of LNG from the LNG Facilities to the LNG Depots in each Municipality. This charge is payable on a pass-through basis, without mark up[115] and is estimated to escalate by 2 percent per annum. [116]

- **Termination Payments**: Termination payments are payable, by the Utility, under certain circumstances, as follows:

  - In the event that the conditions precedent to the parties' obligations are not satisfied or waived within the relevant timeframe specified for satisfaction or waiver and Nipigon LNG or the Utility terminates the LNG Services Agreement, an amount equal to the "reasonable costs incurred by Nipigon LNG for the construction and development of the LNG Depots" is payable.[117]

  - In the event of the bankruptcy or insolvency of the Utility which results in the termination of the LNG Services Agreement by Nipigon LNG, the Utility would be liable to pay an amount referred to as the "Discounted Remaining Obligation".[118, 119] The Municipalities view this to be an appropriate remedy for Nipigon LNG in

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[112] *Ibid* at page 15, Section 3.6; Section 3.6 remains in draft form and will be finalized during the next stage of development; however, for the purposes of Board approval, this provision will result in a reduction in overall cost.

[113] Response to OEB Staff Interrogatory–41(a)–(c).

[114] *Supra* note 48 at page 6, lines 8-9.

[115] Response to OEB Staff Interrogatory–41(d).

[116] *Supra* note 48 at page 6, lines 8-9.

[117] Application, Exhibit A, Tab 13, Schedule 1, Attachment 5, page 23, Section 10.4.

[118] The Discounted Remaining Obligation is defined in the LNG Services Agreement as, "the [Utility's] remaining outstanding, discounted (at ● percent per annum rate) contractual obligation derived from the total Firm Capacity Charges under this Agreement for the remaining Term under this Agreement, as calculated at the beginning of each Contract Year".

[119] *Supra* note 117 at page 22, Section 9.2.

the circumstances and while not an exact approximation for damages that would be recoverable under contract law on a termination, represents a customary approach to quantification of losses in such circumstances.

76. Contract provisions that do not have cost consequences include:

- **Effective Date:** The LNG Services Agreement is not effective until satisfaction of various usual conditions precedent, including receipt of all approvals and agreements to effect the connection of Nipigon LNG's liquefaction plant to the TCPL Mainline;[120]

- **Provision of Firm Capacity**: Nipigon LNG agrees to make available and provide capacity on a firm basis during the term.[121]

- **Nominations**: The Utility is required to make daily nominations with respect to the volumes of natural gas to be liquefied, delivered to the LNG Depots and regasified, for injection into the Distribution System.[122]

- **Termination Rights**: Nipigon LNG may terminate the LNG Services Agreement in the event of the bankruptcy or insolvency of the Utility, a failure by the Utility to provide credit support where it is required in accordance with the terms of the LNG Services Agreement and any defaults by the Utility of the terms of the LNG Services Agreement (including payment defaults) which are not cured within 30 days.[123]

- **Indemnification**: The Utility shall indemnify Nipigon LNG for its losses and damages arising from the acts or omissions of the Utility or breach by the Utility of its representations, warranties or covenants.[124]

- ***Force Majeure***: The LNG Services Agreement includes a customary *force majeure* provision which relieves a party for its failure to perform any covenant or obligation (other than any obligation to make payments due) caused by *force majeure*.[125]

[120] *Supra* note 117 at pages 11-12, Section 3.1.
[121] *Supra* note 117 at page 13, Section 3.2.
[122] *Supra* note 117 at page 13, Section 3.3.
[123] *Supra* note 117at pages 21-22, Section 9.1.
[124] *Supra* note 117 at page 26, Section 12.2.
[125] *Supra* note 117 at page 27, Section 13.1.

(d) **Eligibility of LNG Services Agreement for Pre-approval**

77. The Municipalities are requesting that the Board pre-approve the cost consequences of the LNG Services Agreement for rate-making purposes pursuant to section 36 of the OEB Act. The Pre-Filing Guidelines set out the principles and issues that the Board considers when evaluating such an application. The starting point is for applications for pre-approval of cost-consequences to be in respect of long-term gas transportation or supply contracts that support the development of new natural gas infrastructure. The pre-approval process is not to be used in respect of a utility's "normal" or "typical" transportation or supply contracts or the renewal of such contracts.

78. It is submitted that the Municipalities' application for pre-approval meets these threshold eligibility requirements. First, the LNG Services Agreement is a long-term contract, by any definition. It is for an initial term of ten years, commencing on the first date of commercial operation of the LNG Facilities. The Utility has an option to extend the initial term by a further ten-year period, on the same terms and conditions. This right of renewal will permit the Utility, at its option, to procure the LNG Services for a total of 20 years or, instead, contract with alternative gas suppliers at the end of the initial term, should cost effective and reliable alternative options become available.

79. Second, the LNG Services Agreement supports the development of new natural gas infrastructure, namely the Utility's proposed greenfield Distribution System which will provide the Municipalities with access to natural gas, for the first time. Without pre-approval of the cost consequences of the LNG Services Agreement, the Utility's investors will not commit the capital to finance the Utility and, in turn, Nipigon LNG will not commit to build and operate the LNG Depots. In the result, the residents and businesses of the Municipalities would be exposed to the sustained impacts of having to rely on higher-cost supplies of energy.[126]

80. Third, the LNG Services Agreement is not a "usual," "normal course" or "typical" utility gas transportation contract. Rather, it is the lynchpin of a virtual gas transportation pipeline, extending from a point of interconnection between the LNG Facilities and the TCPL Mainline, to points of interconnections between the LNG Depots and the Distribution System in each of the five Municipalities. The LNG Services will be a link in the chain of natural gas transportation from Alberta to the burner tip.[127]

[126] Application, Exhibit A, Tab 4, Schedule 3.

[127] See Response to OEB Staff Interrogatory-10(b) which describes examples of virtual LNG pipelines operating in other jurisdictions.

(e) **Demonstration of Need & Benefits**

81. The Utility intends to enter into the LNG Services Agreement on behalf of its future customers, for the benefit of these customers. The agreement will provide the Municipalities with access to natural gas for the first time. The benefits of such access were discussed, in detail, in Section IV (b) and (c) above.

(f) **Comparative Cost Analysis of Gas Supply Options**

82. A landed cost analysis that compares the average landed gas supply cost under the LNG Services Agreement with the landed cost of alternative sources of natural gas concludes that the Nipigon LNG supply option is less expensive than, or competitive with, alternative supply options, namely: natural gas supplied by a lateral pipeline from the TCPL Mainline to the Distribution System; CNG; and alternative supplies of LNG.

Pipeline supply options

83. With respect to the pipeline supply option: connecting each of the Municipalities to the TCPL Mainline would require the construction of a new lateral pipeline, approximately 450 kilometres in length. Union Gas completed an opportunity assessment for its 2015 Community Expansion proposal that estimated the capital costs required to expand service to Terrace Bay, Schreiber and Marathon.[128] Union Gas estimated that the capital cost of the 200 km of pipeline required to connect these three municipalities would be $243.97 million. If the additional 250 km of pipeline required to connect the Municipalities of Manitouwadge and Wawa were to be included, the total capital cost for a pipeline supply option would likely exceed half a billion dollars.[129]

84. The capital cost of a pipeline option cannot be supported by the size of the natural gas market within the Municipalities. Assuming $500 million in capital costs and 50-year depreciable life, the depreciation cost, alone, would require the recovery of $10 million per year from ratepayers. This amount does not include the cost of required capital or OM&A. With an assumed return on capital of six percent, the cost of capital would be $750 million over the life of the asset.[130]

[128] EB-2015-0179, Exhibit A-1, Appendix D, page 2.
[129] *Supra* note 107 at page 11, lines 5-13.
[130] *Supra* note 107 at page 11, lines 14-22.

CNG supply option

85. The landed cost of LNG was also evaluated against the landed cost of CNG, assuming a peak day demand of 2,400 GJ, a 100 percent utilization rate and sufficient storage for five days of peak day consumption in each Municipality (notwithstanding the fact that Wawa will require storage for seven days of peak-day consumption).[131] The estimated landed costs for the CNG supply and the LNG supply option are similar. For modeling purposes, it is assumed that the Utility would build and operate a CNG compression facility, near Nipigon, to serve the Municipalities. The annual fixed cost of providing compression, storage and decompression services is estimated to be approximately 15 percent more than the annual cost of the Nipigon LNG Services. This estimate is underpinned by an annual revenue requirement of $7.1 million associated with total capital costs of $42 million (which includes the capital cost of CNG production plant, trailer modules designed specifically for bulk transportation and storage of large amounts of CNG and local decanting depots within each community) and annual OM&A costs of $1.4 million, for a total of $7.1 million per year.[132,133]

86. While LNG production requires higher capital cost than CNG production, per unit of energy, CNG has a lower energy density and requires more storage capacity in high-pressure trailers, which are significantly more expensive to own and operate than stationary LNG tanks that store the same amount of energy. Fixed costs of the LNG supply option are approximately $1 million per year lower than the fixed costs of the CNG supply option, due principally to the cost to store five days of peak demand of natural gas within each Municipality.[134]

87. LNG and CNG have the same commodity and pipeline infrastructure costs, but there is a significant difference when it comes to trucking costs. Both options have the same forecast average cost of $1,016 per delivery; however, each LNG delivery can transport more than 2.5 times as much energy as a CNG delivery. The distance from the Nipigon LNG liquefaction plant to the Municipalities ranges from 110 km (Schreiber) to 385 km (Wawa), with an average delivery distance of approximately 200 km. <u>In consequences, the incremental trucking costs make CNG a costlier option than LNG, under forecast market projection and conditions</u>.[135]

[131] *Supra* note 107 at page 12.
[132] *Supra* note 107 at page 12, lines 9-19.
[133] Response to OEB Staff Interrogatory-11(b).
[134] *Supra* note 107 at page 13, lines 1-6.
[135] *Supra* note 107 at page 13, lines 7-13.

88. Transporting LNG would require an average of two total truck deliveries per day during the winter across the Utility's service area. For each Municipality, it is estimated there would be an average of two to three deliveries per week of LNG. Because of the relatively low energy density of CNG, CNG would require five or more deliveries per day during the winter or more than one delivery per day in each Municipality. As the LNG option reduces the number of trucks on the road by a factor of 2.5 times, it is also better aligned with the Municipalities' desire to maximize supply reliability.[136]

89. Given the circumstances of the Utility, especially the trucking distances and number of storage days required, LNG is the lowest-cost option, based on estimated fixed and variable operating costs and current commodity prices. In addition, LNG provides a higher reliability factor than CNG, as it requires fewer trucks to be on the road, especially during the winter months.[137]

Other LNG supply options

90. Other LNG sources were evaluated as alternatives to the Nipigon LNG supply option. For the reasons discussed below, these alternatives were judged to the impractical and more expensive.

91. Énergir, in Montreal, supplies LNG. However, the delivered costs would be more expensive, reflecting the cost of transporting natural gas to Montreal and LNG from Montreal, to the Municipalities, a distance of 1,400 km (vs. an average delivery distance from Nipigon LNG supplies of only 225 km). The longer LNG delivery time for Énergir supplies also increases the risk of delays, which reduces the reliability of the supply.[138] LNG supplies are also available from Minneapolis, Minnesota. This would require a 900 km trip to deliver LNG to the Municipalities, with the additional risk of delays at the Canada-US border.

92. The estimated delivered cost of Montreal or Minneapolis LNG ranges from $16 to $18/GJ, exclusive of the costs of LNG Depot storage and regasification, compared to $8.31/GJ, the landed cost of Nipigon LNG, inclusive of LNG Depot storage and regasification.[139]

93. Enbridge has an LNG facility at Hagar, Ontario. However, the capacity from this facility is required to meet the system integrity requirements of the Union North system.[140] Enbridge did

[136] *Supra* note 107 at page 13, lines 14-19.
[137] *Supra* note 107 at page 14, lines 8-12.
[138] *Supra* note 29 at page 27.
[139] *Ibid*.
[140] EB-2014-0012.

consider selling limited additional LNG volume to the transportation market,[141] however, Enbridge would only sell this additional volume on a fully interruptible basis. Interruptible supplies do not meet the reliability requirements for the Distribution System.[142]

94. In 2014, Union Gas, filed an application (EB-2014-0012) with the Board for approval of an interruptible LNG service rate of $5.096/GJ ($5.74/GJ in 2020 dollars, adjusted at 2 percent/yr). To this, would have to be added the costs of LNG Depot storage and regasification and the cost of trucking the Hager supplies to the five Municipalities. Moreover, the Hagar service is not comparable to the Nipigon LNG service because it is an interruptible service that can be interrupted at any time. Even when it is available, it is unlikely that the Utility's full winter requirements could be met by Hager supplies. In contrast, the Nipigon LNG Service will be a firm service, available 24-7, 365 days/year, subject to planned and unplanned outages.

(g) **<u>Risk Assessment</u>**

95. If the cost consequences of the LNG Services Agreement are pre-approved by the Board, the Utility's ratepayers will receive the benefits of access to natural gas for the first time. These benefits, already enjoyed by millions of other Ontarians, were discussed earlier in this submission. The Utility's ratepayers will also benefit from terms and conditions in the LNG Supply Services Agreement that:

- ensure entitlement to firm liquefaction capacity, enabling the Utility to satisfy customer demand with a reliable supply of natural gas;
- relieve the Utility from the obligation to pay the Firm Capacity Charge in circumstances where Nipigon LNG fails to deliver the nominated quantities of natural gas;
- shape the contracted firm capacity during the term of the agreement to reflect growth in customer demand, over time; this provides all the benefits of firm capacity but minimizes the cost because the Utility will not be required to purchase and pay for firm capacity in the early years of the contract, at levels that will only be required by year 10 of its operation;
- provide on-site natural gas storage in each Municipality (i.e., the LNG Depots), with security of supply for between five and seven days;

[141] *Ibid*.
[142] *Supra* note 29 at page 27.

- provide for an initial ten-year term that may be extended to 20 years, if the LNG Services Agreement continues to represent the most cost effective and reliable means of delivering natural gas to the Distribution System;

- provide the flexibility to withdraw from the LNG Services Agreement after ten years, if more cost effective and/or reliable supply options become available; and

- create a relationship with a motivated partner, Nipigon LNG, whose own commercial interests are aligned with the interest of the Utility, as demonstrated by Nipigon LNG's commitment to provide the Utility with firm liquefaction capacity and to construct the LNG Depots.

Supply Risk

96. The Distribution System presents unique risks by virtue of its remote location; it cannot be connected economically to a major transmission pipeline. Reliance on Nipigon LNG as a single source of gas supply could also put the Utility at risk in the event of an unplanned outage of the LNG Facilities or financial difficulties that may be experienced by Nipigon LNG. These risks are mitigated as follows:

- It is technically possible for the Distribution System to receive and deliver both LNG and CNG-sourced natural gas (assuming that the CNG provider is able to supply natural gas in accordance with the temperature and pressure requirements of the Distribution System and assuming that the CNG provider would own and operate all necessary unloading, heating and regulation facilities and arrange for its own utility services to support its operations).[143]

- It would also be possible for the Distribution System to receive alternative supplies of LNG from Montreal and/or Minneapolis. Montreal to Marathon is about 1,400 km, which would require an approximately 15-hour, one-way trip. The LNG supply source in Minneapolis is approximately 900 km from Marathon and would require approximately a 9-hour, one-way trip. Supplier-sourced LNG tankers could be accessed to deliver gas to the Distribution System, if necessary. It is anticipated that emergency protocols would be put in place with these suppliers, in advance, in order to minimize the delivery period.[144]

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[143] Response to OEB Staff Interrogatory-11(c).
[144] Response to OEB Staff Interrogatory-31(b).

- If Nipigon LNG is not required to suspend operations of the LNG Depots, ratepayers will continue to be supplied for between five and seven days depending on location.[145, 146] As is the case with all modern gas supply systems, there will be provisions for continued system integrity in the case of planned and unplanned LNG Depot maintenance. The Distribution System will be equipped with a connection, downstream of each LNG Depot (within the confines of the Depot site) where natural gas can be injected from a temporary source. The temporary source could be a mobile LNG storage and vaporizer arrangement or a CNG trailer with pressure reduction equipment. These types of arrangements have been shown to provide satisfactory back-up for many weeks and would allow for a wide range of maintenance activities at the LNG Depots.[147]

- Supply of natural gas to the Utility's interruptible loads could be curtailed in events of LNG supply difficulties.

Truck Delivery Risk

97. Weather events, such as snowstorms and heavy fog, may prevent LNG delivery trucks from delivering LNG from the LNG Facilities to the LNG Depots. Snowstorms can result in road closures over wide-spread geographic areas and can persist for extended periods of time, thereby preventing deliveries along alternative routes. Physical events, such as washouts and road accidents, can also result in road closures. Truck delivery risk is mitigated as follows:[148]

- Road damage caused by physical events (e.g., washouts) can generally be repaired in relatively short periods of time. As such events tend to be localized, alternative delivery routes can accommodate LNG deliveries, although delivery times may increase.

- In order to mitigate truck delivery risk, generally, and particularly in the case of snowstorms, the LNG Depots have been sized to store LNG in quantities sufficient to provide supply during anticipated periods of truck delivery failure; the amount of "backup" supply was determined as follows:

    - Highway 17 is a federally-owned highway which is maintained provincially and LNG delivery trucks will use this highway as the primary route to deliver LNG

[145] Response to OEB Staff Interrogatory-31(a).
[146] *Supra* note 29 at page 37, section 2.8.4.2.
[147] Response to OEB Staff Interrogatory–45.
[148] *Supra* note 29 at pages 38-42.

from the Nipigon LNG liquefaction plant, to the LNG Depots. In order to assess the reliability of Highway 17 and calculate the required level of storage, statistical information was obtained from Statistics Canada, Transport Canada and the Ministry of Transportation of Ontario to show that the frequency of road closures. South of Wawa the frequency of closures is greater than the rest of the area between Nipigon and Wawa. Anecdotal information confirms that the area to the south of Wawa is more prone to lake-effect snow. The highest number of consecutive days when Highway 17 was closed, that could be recalled, was three days.

- To further increase the factor of safety, it was assumed that for the day prior to the closure and the day after the road reopened, travel times would be longer than normal and, for purposes of designing the storage capacity, these days should also be considered as "non-delivery" days. Therefore, the LNG Depot storage has been designed to accommodate a total of five days of supply when trucks are unable to deliver LNG to the LNG Depots, although it is highly unlikely that five design days will occur in a row, which further increases the factor of safety of this design standard. While five days is considered to be sufficient for all Municipalities, as noted earlier the area south of Wawa has a greater potential to be closed due to local snowstorms; accordingly, an additional two days of storage is being provided for Wawa to increase the reliability of supply. The amount of LNG Depot storage will be re-evaluated on an ongoing basis. If demand is occurring faster than forecast, then more storage could be added. If demand is growing more slowly than expected, then additional storage can be phased-in, over a longer period.

LNG Facilities Design Risk

98. The design of the LNG Facilities will be critical to their operational reliability and efficiency. Poor design will create ongoing operational and outage risk. This risk is mitigated as follows:

- The Nipigon LNG plant will use proven, low-complexity technologies for gas pre-treatment and liquefaction. Pre-treatment will be accomplished using a mole-sieve Temperature Swing Absorption (TSA) system. Liquefaction will be done by a double nitrogen expansion process. Both of these systems are commonly used in small-scale LNG production. An important factor in the selection of these systems is design and operational simplicity. Moreover, the providers of these systems are leaders in the marketplace and have significant experience in designing small scale LNG production facilities.

- Nipigon LNG has 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, its technology risk is insignificant. The LNG Facilities will be designed with a high regard to reliability; for example, with respect to the selection of site-appropriate equipment and adoption of piping specifications. Potential equipment suppliers will be screened to ensure that only experienced suppliers are selected.

- Further, Nipigon LNG has had several discussions with the TSSA regarding the design of the LNG Depots. TSSA has confirmed the following: (i) piping designs for the LNG Depots are to be registered and pressure components must have Canadian Registration Numbers (CRN); (ii) electrical equipment at the LNG Depots must be designed and installed in accordance with the Canadian Electrical Code and local amendments; and (iii) any natural gas-fueled appliances and equipment to be included in the LNG Depots will be regulated by the TSSA's Fuel Safety Program. Nipigon LNG will continue engagement with TSSA, as necessary and appropriate.

- Finally, in January 2018, Infrastructure Ontario undertook a technical and financial review of the Nipigon LNG project, as a condition of advancing funding under the Natural Gas Grant Program. It concluded that the Nipigon LNG project would comply with industry standards and best practices, was technically feasible and was underpinned by a procurement strategy designed to minimize risk. Northeast Midstream has assembled a strong management team, and the company, itself, is reputable and credit worthy.[149]

LNG Facilities Construction Risk

99. The risk associated with construction relates, principally, to factors that could cause delays in the commencement of the provision of the LNG Services. These risks are mitigated as follows:

- The risk of delays may be mitigated through the temporary use of alternate sources of natural gas supply, as discussed above.

[149] Response to SEC Interrogatory–18(d) and (e).

- With respect to cost overruns: It is anticipated that Nipigon LNG will implement project management models that monitor and manage the construction process and will contract with constructors and suppliers in a manner that shifts appropriate risk to such parties, where it is cost effective to do so. Further, under the LNG Services Agreement, Nipigon LNG has no right to amend the fees payable by the Utility in the event of cost overruns.[150]

Regulatory Risk

100. TCPL will require approval of the Canadian Energy Regulator ("**CER**") to construct connection and metering facilities at the interconnection between the TCPL Mainline and the LNG Facilities. There is a risk that the CER may not approve the construction of these facilities. This risk is mitigated as follows:[151]

- On May 7, 2019, TCPL and Nipigon LNG entered into a commercial agreement to effect the design, construction and commissioning of the interconnection and metering, prior to the commissioning and start-up of the Nipigon LNG liquefaction plant. The engineering and design of these facilities is currently underway, in anticipation of an application to the CER for the required approvals. The risk that the CER does not approve the construction of the facilities is very low. The Utility expects that TCPL and Nipigon LNG will uphold their respective commitments to advance the interconnection facilities in accordance with applicable rules and regulations and with TCPL's Conditions of Service.

Variable Charges Risk

101. Under the LNG Services Agreement, the Utility is liable to pay variable charges and truck delivery charges, as follows:[152]

- The current Variable Charge estimate for LNG delivered to the Distribution System is $0.44/GJ, based on current commodity and market prices. The Variable Charge comprises the Utility's *pro-rata* share of the cost of natural gas, electricity, nitrogen and other items consumed in the liquefaction and regasification process.

[150] Response to Certarus Interrogatory–1(a).
[151] Response to OEB Staff Interrogatory–29.
[152] Response to OEB Staff Interrogatory–41.

- Under the LNG Services Agreement, Nipigon LNG will set the variable charge, without markup, and the Utility will have the right to audit the Variable Charge pursuant to section 7.5 of the LNG Services Agreement.

- The current estimate of the cost of LNG truck delivery, from Nipigon LNG to the LNG Depots, is $2.54/km. This estimate was provided by Nipigon LNG, based on a request for proposal that Nipigon LNG conducted in the Spring of 2019. It is not a firm price. The truck transportation services agreement between Nipigon LNG and the third party service provider will be subject to a commercial negotiation.

- Based on the currently available information, the Utility expects to pay approximately $0.84/GJ for truck transportation services. This estimate assumes a weighted average distance of 200 km (one-way) for LNG deliveries, excluding LNG deliveries to any large industrial customer. Trucking costs are also to be passed through by Nipigon LNG, without markup, and the Utility's audit rights described above will also apply to these charges.

Other Considerations

102. **Affiliations:** The proposed LNG Services Agreement is between two arm's length parties. Nipigon LNG is not affiliated with the Municipalities and will hold no equity or other interest in the Utility. Similarly, neither the Municipalities nor the Utility are affiliated with Nipigon LNG and neither hold or will hold any interest in Nipigon LNG.

103. **Retail Competition:** It is not expected that the LNG Services Agreement will have any impact on retail competition for natural gas in Ontario or on any other Ontario gas distributor.

104. **Upstream Transportation:** With respect to the availability of upstream transportation on the TCPL Mainline, it is noted that a significant surplus of capacity exists on that line.[153]

VI. <u>CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY & MUNICIPAL FRANCHISE AGREEMENTS</u>

(a) <u>Certificates</u>

105. The Municipalities seek an order or orders under s. 8 of the *Municipal Franchises Act*, granting the Utility Certificates that authorize the construction of the Distribution System in each of the

[153] *Supra* note 29 at page 35, Section 2.8.3.

Municipalities. Proposed forms of Certificates are included in the response to OEB Staff Interrogatory – 25(b).

106. The Municipalities are requesting that the Certificates be issued to MEDC, as a proxy for the Utility. Immediately after the Utility is fully constituted and organized, MEDC will make an application to the Board, under s. 18(1) of the OEB Act, for leave to transfer the Certificates to the Utility.

107. There is OEB precedent for issuing Certificates prior to the issuance of a LTC order (or, in this case, prior to the issuance of an unconditional LTC). In its Decision and Order in EB-2016-0137/EB-2016-0138/EB-2018-0139 (April 12, 2018), the Board issued Certificates to EPCOR prior to its application for an LTC Order.

108. The issuance of Certificates at this stage appropriately balances two competing objectives. On the one hand, the Municipalities require as much regulatory certainty as is reasonably possible, in order to obtain preliminary financing. On the other hand, the Board must satisfy itself that the Utility that holds the Certificates has the financial and technical capacity to carry out the authorized activities. Issuance of the Certificates, at this stage, would create a greater degree of regulatory certainty, enhancing the Municipalities' ability to obtain financing. It would also preserve the Board's ability to satisfy itself that the Utility possesses the technical ability and financial capacity required to construct, own and operate the Distribution System. This is because the Utility will not be able to act under the authority of the Certificates unless and until the Board is satisfied that the Utility has fulfilled the conditions included in the LTC order.

(b) **Municipal Franchise Agreements**

109. The Municipalities seek:

(i) an order under s. 9 of the *Municipal Franchises Act*, approving the terms and conditions of the Municipal Franchise Agreements that will be entered into between each of the Municipalities and the Utility, which agreements will grant the Utility the right to construct and operate the Distribution System in the Municipality; and

(ii) an order or orders under s. 9 of the *Municipal Franchises Act*, directing and declaring that the assent of the municipal electors of each Municipality to that Municipality's by-law granting the Utility the right to construct and operate the Distribution System, is not necessary.

110. The proposed form of Municipal Franchise Agreement included in the Application is the form of the Board's Model Franchise Agreement (the "**Model Franchise Agreement**").[154] As the Project is a greenfield project, the proposed form of Municipal Franchise Agreement adopts clause 4 (a) of the Model Franchise Agreement, as opposed to clause 4 (b), in accordance with the Board's ruling on this issue in Decision and Order dated July 11, 2019 in EB-2018-0263.

111. Finally, and also in accordance with prior OEB rulings,[155] the Municipal Franchise Agreements will not be executed by the parties unless and until the Board has approved the proposed form of agreement.[156]

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 11TH DAY OF DECEMBER 2019.

DENTONS CANADA LLP

Per:

original signed by Helen T. Newland
Helen T. Newland

original signed by Vivek Bakshi
Vivek Bakshi

[154] Application, Exhibit A, Tab 6, Schedule 1, Attachment 2.
[155] Decisions and Orders E.B.O 125 and EB-2018-0263.
[156] Application, Exhibit A, Tab 6, Schedule 1, Attachment 3.