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

BY EMAIL

February 21, 2024

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
Registrar@oeb.ca

Dear Ms. Marconi:

Re: Ontario Energy Board (OEB) Staff Submission
Leave to Construct Application - Waasigan Project
OEB File Number: EB-2023-0198

Please find attached OEB staff's submission in the above referenced proceeding, pursuant to Procedural Order No. 4.

Yours truly,

Vithooshan Ganesanathan
Digitally signed by Vithooshan Ganesanathan
Date: 2024.02.21 14:51:19 -05'00'

Vithooshan Ganesanathan, Advisor
Generation & Transmission

Encl.

cc: All parties in EB-2023-0198

ONTARIO ENERGY BOARD

OEB Staff Submission

Hydro One Networks Inc.

Leave to Construct Application - Waasigan Project

EB-2023-0198

February 21, 2024

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1. Background and Overview

1.1 Overview of the Application

On July 31, 2023, Hydro One Networks Inc. (Hydro One) applied to the Ontario Energy Board (OEB) for orders under sections 92 and 97 of the *Ontario Energy Board Act,1998* (Act), seeking approval to construct approximately 360 kilometres (km) of electricity transmission line and modify associated facilities to connect the new transmission line at the terminal stations (Project). Hydro One stated that the Project is required to increase long-term transmission capacity in northwest Ontario in the regions of Thunder Bay, Rainy River and Kenora.

The Project consists of two phases. Phase 1 of the Project consists of a new 230 kV double-circuit transmission line that will span 190 km from the existing Lakehead Transmission Station (TS) to the existing Mackenzie TS. Phase 2 of the Project consists of a new 230 kV single-circuit transmission line spanning 170 km from the existing Mackenzie TS to the existing Dryden TS. The Project will include terminal station modifications at the Lakehead TS, Mackenzie TS, and Dryden TS to accommodate the proposed transmission circuits.

Hydro One has also applied to the OEB for approval of the form of land use agreements it offers to landowners for the routing and construction of the Project.

1.2 Overview of OEB Staff Submission

OEB staff does not oppose Hydro One's section 92 request for leave to construct, subject to the standard conditions of approval set out in Section 2.8 of this submission.

As detailed in this submission, OEB staff has specific concerns with regards to the estimated costs for the line portion of the Project. OEB staff recommends that a portion of these costs (i.e., $144 million) be subject to further review in the Project's cost-based transmission revenue requirement proceeding.

Furthermore, OEB staff can neither support nor dispute the proposed new overhead capitalization methodology. OEB staff submits that the current proceeding is not the appropriate type of proceeding for considering such an issue and that it should be addressed in the Project's cost-based transmission revenue requirement proceeding.

As part of the revenue requirement proceeding, OEB staff recommends further evidence on the following be provided:

- Additional information on why the Project's line costs are higher than that of the comparator East-West-Tie (EWT) project

- Contingency estimates for line costs
- New Overhead Capitalization Methodology

OEB staff supports Hydro One's section 97 request for approval of the forms of agreements it will offer to affected landowners. OEB staff's submission is provided in detail in the following sections.

1.3 OEB's Jurisdiction in Section 92 Applications

The criteria for the OEB's considering of an application under section 92 is found in section 96 of the Act which states:

> **96** (1) If, after considering an application under section 90, 91 or 92 the Board is of the opinion that the construction, expansion or reinforcement of the proposed work is in the public interest, it shall make an order granting leave to carry out the work.
>
> (2) In an application under section 92, the Board shall only consider the following when, under subsection (1), it considers whether the construction, expansion or reinforcement of the electricity transmission line or electricity distribution line, or the making of the interconnection, is in the public interest:
>
>> 1. The interests of consumers with respect to prices and the reliability and quality of electricity service.

Section 97 of the Act states that leave shall not be granted under section 92 until the applicant satisfies the OEB that it has offered or will offer to each owner of land affected by the approved route or location an agreement in a form approved by the OEB.

2. OEB Staff Submission

2.1 Project Need & Project Alternatives

Project Need

As part of its application, Hydro One filed evidence demonstrating need for the Project, including an Order in Council (OIC) and Directive issued by the Minister of Energy under section 28.6 of the Act, to amend the electricity transmission licence issued to Hydro One to include a requirement that Hydro One proceed to develop and seek approvals for the Project.[1]

On January 9, 2014, the OEB updated Hydro One's license[2] requiring, amongst other things, that Hydro One work with the Independent Electricity System Operator (IESO) (at the time the Ontario Power Authority) to establish the scope and timing of the transmission project referred to in the OIC and develop and seek approvals for the Project (at the time referred to as the Northwest Bulk Transmission Line Project).[3]

With regard to Project need, the IESO's May 3, 2022[4] and April 24, 2023[5] letters to Hydro One described that the Project was required to increase the electricity supply to the region west of Thunder Bay, provide a means for new customers and growing loads to be served with clean and renewable sources that comprise Ontario's supply mix and enhance the potential for development and connection of renewable energy facilities.

In the IESO's Waasigan Transmission Line Project: Need, Alternatives, and Recommendations Report (IESO Report),[6] the IESO stated that the need identified in the region is based on an outlook for growth based largely on the development of new mining projects and the electrification of existing mining activities in the region.

The IESO Report further noted that the electricity system today within the region is close to capacity. Due to the size of the proposed mining projects, the IESO stated that if even one of the larger projects seeks grid connection in the region, additional supply capacity will be required to meet the increased demand. The IESO stated that some of the risks with not building additional capacity now include new customers not being able to connect or reliability degrading in the region, which can lead to stifling economic

[1] Exhibit B, Tab 3, Schedule 1, Attachment 1, Order in Council and Minister's Directive dated December 11, 2013.
[2] ET-2003-0035.
[3] EB-2013-0437, Decision and Order, January 9, 2014.
[4] Exhibit B, Tab 3, Schedule 1, Attachment 7.
[5] Exhibit B, Tab 3, Schedule 1, Attachment 8.
[6] Exhibit B, Tab 3, Schedule 1, Attachment 9, IESO Report Waasigan Transmission Line Project: Need, Alternatives, and Recommendations.

growth.

Furthermore, the IESO's January 2023 regional planning report (Integrated Regional Resource Plan - Northwest Region)[7] contains evidence of the Project's need and benefits for the power system in the region.

Project Alternatives

Hydro One's evidence in this proceeding relies on the IESO Report which describes needs in the region emerging as a result of anticipated demand growth under various demand forecast scenarios, discusses alternatives considered to meet the needs, and recommends the construction of the Project to meet the region's needs. The IESO Report states that the "IESO considered several alternatives to address the needs arising under each of the Region's demand forecast scenarios, including transmission reinforcement, incremental conservation and demand management (CDM), new non-emitting supply resources (including storage), and new gas-fired generation".[8] The IESO Report states that the non-wire alternatives considered were not viable solutions.

Hydro One considered four conductor size alternatives for the Project that consisted of different Aluminium-Conductor Steel-Reinforced cable (ACSR) conductor sizes: 795 kcmil, 997 kcmil, 1192 kcmil, and 1443 kcmil. Hydro One stated that the conductor size alternatives that were considered would meet the supply forecast needs and be optimal options for line loss reduction for the expected load scenario. In an interrogatory response,[9] Hydro One stated that the conductor size alternatives that were considered are based on standard conductor sizes used across Hydro One's transmission system, growing progressively larger from 795 kcmil to 1443 kcmil. Hydro One noted that ACSR 795 kcmil, Hydro One's preferred alternative, is the minimum conductor size that would suitably address the supply load need for each phase of the Project.[10]

Hydro One undertook a 50-year net present value (NPV) analysis of the alternatives using Alternative 1 (ACSR 795 kcmil) as the base scenario.[11] The NPV analysis used a 5.65% discount rate for the incremental capital cost. An incremental NPV sensitivity analysis was completed to incorporate line loss reduction of the alternatives at different Hourly Ontario Energy Prices (HOEP). The results of the NPV analysis have been summarized in the table below.

[7] Exhibit H, Schedule 1, Tab 1, Attachment 1.
[8] IESO Report, Exhibit B, Tab 3, Schedule 1, Attachment 9.
[9] Interrogatory response to OEB Staff 6c).
[10] Interrogatory response to OEB Staff 6a).
[11] Exhibit B, Tab 5, Schedule 1, pp. 3-4.

Table 1: NPV Analysis

	Alt # 1[12] 795 kcmil	Alt # 2 997 kcmil	Alt # 3 1192 kcmil	Alt # 4 1443 kcmil
Incremental Capital Cost ($M's)	0.0	5.0	9.5	12.5
Incremental OM&A ($M's)	0.0	0.0	0.0	0.0
Annual Losses (MWh)	11,961.4	9,751.1	8,413.8	6,942.8
Energy Price $/MWh	**Incremental Net Present Value ($M)**			
	Alt # 1 795 kcmil	**Alt # 2 997 kcmil**	**Alt # 3 1192 kcmil**	**Alt # 4 1443 kcmil**
$47.30	0.0	-1.7	-3.9	-4.8
$80.00	0.0	0.1	-1.1	-0.8
$120.00	0.0	2.3	2.4	4.1

Hydro One stated that Alternative 1, has the lowest incremental NPV based on capital costs alone and also has the lowest incremental NPV if losses are included at a HOEP of $47.30/MWh[13].

Hydro One emphasized that according to the NPV energy price sensitivity analysis, at around a HOEP of $78/MWh, the cost effectiveness of both Alternative 1 and Alternative 2 (997 kcmil) becomes equal.

Submission

OEB staff submits that the evidence has demonstrated the need for the Project to increase long-term transmission capacity in northwest Ontario as indicated in the OIC, Minister's Directive and recommended in the IESO Report. OEB staff agrees that there is a need to increase supply in the region based on a projected growth of mining developments and the electrification of existing mining activities, as noted in the IESO Report.

OEB staff take no issue with IESO's conclusion that a non-wire alternative is not a viable solution for the requirements of this Project.

Hydro One stated that Alternative 1 is the most economical conductor size option.

[12] Hydro One's preferred alternative.
[13] Hydro One stated that $47.30/MWh is the 2022 average HOEP forecast as per the IESO's 2022 Planning Outlook Report.

Hydro One's rationale is that Alternative 1 is cost-effective when considering both capital costs and line losses in comparison to the other options.

However, OEB staff observes that the differences in costs between Alternative 1 and Alternative 2 are marginal. Alternative 2 is 0.4%[14] higher in costs than Alternative 1. In scenarios where HOEP increases past $78/MWh, the NPV sensitivity analysis demonstrates that Alternative 2 is marginally more economic, while in scenarios where HOEP is below $78/MWh, Alternative 1 is marginally more economic.

Given that there is no material cost difference between Alternative 1 and Alternative 2, OEB staff does not oppose Hydro One selecting Alternative 1 as the proposed option.

2.2 Proposed Route

Hydro One is required as a condition of its licence to develop and seek approvals for a new 230 kilovolt double-circuit transmission line in the area west of Thunder Bay. The licence condition does not establish a detailed route that the transmission line is required to follow. Hydro One filed a map of the route for the Project with the application.

Hydro One's Environmental Assessment (EA) evaluated four route alternatives based on natural environment, socio-economic environment, technical and cost related matters, and Indigenous consultation criteria.[15] The EA established the preferred route proposed in the application based on its performance against the aforementioned criteria. This is the route that Hydro One has proposed for the Project in the application.

Neighbours on the Line (NOTL) and Larry Richard, approved intervenors in the proceeding, stated that alternative routes, which they each proposed, would be more cost effective than the preferred route proposed by Hydro One in the application.[16] In response to these claims,[17] [18] Hydro One explained that in comparison to its proposed route, the routes proposed by NOTL and Larry Richard would introduce increased costs, negatively impact Indigenous and natural environments and/or not meet the IESO's system planning requirements.[19]

Submission

The purpose of the OEB's leave to construct review process is to consider whether the

[14] 0.4% = $5 million / $1,200 million.
[15] [Final Environmental Assessment Report for the Waasigan Transmission Line, p. 2.2-10.]
[16] NOTL letter to the OEB, November 16, 2023.
[17] Interrogatory response to OEB Staff 5(a).
[18] Interrogatory response to Larry Richard 1(a), updated on January 22, 2024.
[19] The requirement for the Project to connect through the Mackenzie TS in Atikokan (Exhibit B, Tab 3, Schedule 1).

Project as filed is in the public interest based on the criteria established in section 96(2) of the Act. OEB staff has no concerns with the proposed route of the Project as it relates to the interests of consumers with respect to prices and the reliability and quality of electricity service.

OEB staff submits that the maps that Hydro One has provided with the application satisfy the requirements of the Act and issue 6.1 of the standard issue list for leave to construct applications.

OEB staff has not yet seen the submissions of the intervenors. However, from the various correspondence and interrogatories, it appears that some intervenors may argue that Hydro One's preferred route for the Project is less cost-effective when compared to the alternative routes proposed by these intervenors.

OEB staff acknowledges that price is a key consideration in a section 92 application and recognizes that the route of the transmission line can have a material impact on the overall price that is passed on to consumers through rates. However, OEB staff notes that the detailed route selection is determined in the EA process. The EA's assessment of the Project's detailed route is comprehensive, evaluating various criteria such as natural environment, socio-economic environment, technical and cost related matters, and Indigenous consultation.

The completion of the Project depends on the final EA that is approved by the Ministry of the Environment, Conservation, and Parks. The OEB's review process for leave to construct applications aims to determine if the Project, as proposed, serves the public interest according to criteria outlined in section 96(2) of the Act.

2.3 Project Cost

The estimated capital cost of the Project is $1,200 million, including $993.7 million for line work and $206.3 for station work.

Hydro One's estimated Project cost includes a contingency amount in recognition of risks. The top three project risks include land acquisition, engagement and consultation, and approvals, permit and authorizations.

The application stated the transmission line facilities comprising the Project will become owned by a future limited partnership that will offer a 50% equity stake to nine First Nation partners. Gwayakocchigewin Limited Partnership[20] represents eight of the nine

[20] The Gwayakocchigewin Limited Partnership First Nations include Wabigoon Lake Ojibway Nation, Eagle Lake First Nation, Lac La Croix First Nation, Fort William First Nation, Seine River First Nation, Lac Seul First Nation, Nigigoonsiminikaaning First Nation, and the Ojibway Nation of Saugeen.

First Nations partnering with Hydro One on the Project, with the ninth partner being Lac des Mille Lacs First Nation.

At the time the application was submitted to the OEB, the formation and structuring of the limited partnership had not been finalized, and hence, commercial details of the partnership were not provided. Hydro One stated that any limited partnership agreement is not anticipated to impact the cost estimate of the Project.[21]

In relation to the line work, Hydro One cited four recent double-circuit 230 kV line projects in Ontario. Three of the four projects, Hawthorne to Merivale,[22] Powering South Nepean[23] and Woodstock Area Transmission Reinforcement (WATR) Projects[24] were constructed by Hydro One while the fourth, the EWT Project,[25] was constructed by Upper Canada 2 Transmission Inc. (UCT).

In its pre-filed evidence, Hydro One stated that the total project costs per km of line for the comparator projects were between $2.4 million and $4.1 million, while the line portion of the Project is estimated to cost $2.6 million per km.

Table 2: Line Costs of Comparable Line Projects[26]

	Hawthorne to Merivale	Powering South Nepean	WATR Projects	East-West Tie Project	Waasigan Project
Line Cost ($M)	39.4	51.3	35.6	935.9	992.7
Escalation Adjustment ($M)	5.4	8.8	13.7	169.88	N/A
Total Line Cost with Adjustment ($M)	43.9	49.7	44.5	1,082.5	N/A
Line Length (km)	12.0	12.2	13.6	450	360
Cost per km ($M/km)	3.7	4.1	3.3	2.4	2.6

Hydro One stated that while the Project line costs are within a reasonable range to that of the comparator projects, the instances where the Project is higher in line unit costs

[21] Interrogatory response to OEB Staff 2.
[22] EB-2020-0265.
[23] EB-2019-0077.
[24] EB-2007-0027.
[25] EB-2017-0182.
[26] Exhibit B, Tab 7, Schedule 1, p. 11, Table 7.

are driven by procurement costs and engagement and consultation.

In its prefiled evidence, Hydro One explained that global procurement challenges, which the Project faces, began after the procurement activities for the comparable projects were undertaken. Hydro One stated that increases in the price of essential commodities (e.g., copper, aluminum, and steel) and supply chain shortages have led to increases in costs for equipment purchased to construct transmission lines (e.g., steel towers, conductors and miscellaneous hardware).

With respect to engagement and consultation, Hydro One stated that there was a significant difference between the Project and the comparators in terms of the magnitude of engagement and consultation required both on the development and execution of the Project. Hydro One explained that the number of stakeholders involved in the engagement and consultation process for the Project far exceeds the comparator projects completed by Hydro One. Hydro One was not able to comment if there were material differences between the consultation work for the Project and the EWT project as the EWT project was constructed by UCT, a party unrelated to Hydro One.[27] The factors that affected engagement and consultation costs included the requirement to carry out the Crown's Duty to Consult and the number of stakeholders in the Project.

In a response to an interrogatory,[28] Hydro One provided revised comparator cost estimates of the EWT project with varying adjustments that produced unit costs per km of line of $2.2 million, $2.5 million and $2.8 million.

In relation to the station work, Hydro One cited three stations (Wawa TS, Marathon TS, Lakehead TS) for Phase 1 and two stations (Holland TS and Beach TS) for Phase 2 for comparison purposes. For Phase 1, per station costs for the comparator projects ranged from $58.9 million and $81.8 million, while the two stations for the Project are estimated to be $62.6 million and $87.9 million. For Phase 2, per station costs for the comparators ranged from $28.5 million and $35.8 million, while the two stations for the Project were $14.0 million and $36.9 million. Hydro One stated that as a result of major differentiating factors, based on the unique site and station configuration, comparing station cost components as a one-to-one comparison is difficult. Hydro One stated that the major differences contributing to the price variation of the station projects include procurement, execution methodology, and project scope.

In its Argument-in-Chief, Hydro One stated that while Phase 1 and Phase 2 station costs appear to be on the higher end amongst the comparators, based on cost alone, comparing station costs is not a linear exercise due to the variation in scope of work for

[27] Interrogatory response to OEB Staff 11(c).
[28] Interrogatory response to OEB Staff 12(c).

each station.[29] Hydro One stated that transformer stations by their very nature are individually unique, complex and are not suitable for a comparative exercise on a per unit basis.[30]

Submission

OEB staff does not oppose the estimated costs for the proposed Project.

However, OEB staff submits that the line portion of the Project costs appear to be $144 million higher than that of the EWT project when considering costs on a per unit km basis. OEB staff recommends that these costs (i.e., $144 million) be subject to further review in the Project's cost-based transmission revenue requirement proceeding. As part of that proceeding, OEB staff recommends further evidence on the following be provided:

- Additional information on why the Project's line costs are higher than that of the EWT project
- Contingency estimates for line costs
- New Overhead Capitalization Methodology

OEB staff's rationale for making this recommendation is summarized in the following sub sections:

1. Line Costs for the Project are higher than the comparator project
2. Hydro One's justifications for higher costs are generally reasonable, but additional information would have been helpful
3. The Project's contingency estimates appear to be high
4. The proposed New Overhead Capitalization Methodology should be tested in the Project's first cost-based rates application (see section 2.4 for more details)

1. Line Costs for the Project are higher than the comparator project

In the prefiled evidence, Hydro One calculated the line cost for the Project to be $2.6 million per km. While Hydro One has provided various cost estimates for the EWT project, OEB staff believes the appropriate comparator estimate to be $2.2 million per km.

OEB staff submits that no regard should be given to the other EWT related cost estimates submitted by Hydro One given that they are inflated and include incomparable Covid-19 related expenses such as employee hotel quarantine costs,

[29] Argument-in-Chief, p. 19.
[30] Argument-in-Chief, p. 19.

contract costs for cleaning/sanitizing and charter flight costs. As confirmed in an interrogatory response,[31] Hydro One does not anticipate incurring Covid-19-related costs similar to those referenced in the EWT project. OEB staff therefore submits that EWT project's costs related to Covid-19 should be discounted from the analysis. It should also be noted that the EWT project's Covid-19 costs are subject to review in an active proceeding.[32]

Based on the estimates noted, OEB staff calculates that the Project is approximately 18% higher on a cost per km line basis than the EWT project. It is important to note that this estimate is inflation adjusted based on the OEB's inflation parameters. If inflation was not considered (i.e., nominal), the Project is approximately 45% higher on a cost per km line basis than the EWT project.[33]

OEB staff is of the opinion that the EWT project is the only fair comparator of the four comparator projects used in Hydro One's unit line cost analysis due to the length of the transmission lines. OEB staff notes that three of the four comparator projects cited by Hydro One – Hawthorne to Merivale, South Nepean DETL and WATR – have significantly smaller line lengths in comparison to the Project. For reference, the Project is in the range of 26 to 30 times in magnitude longer than the line lengths for these three comparators.

In its prefiled evidence, Hydro One stated these projects were selected as reasonable comparators because they are 230 kV double-circuit transmission lines, they utilize similar conductor types, and they are either completely or predominantly built using steel lattice structures.[34]

OEB staff submits that due to the Hydro One projects being notably shorter in length compared to both the Project and the EWT project, the cost per unit km analysis is more favourable towards the Project and the EWT project as a result of economies of scale. In an interrogatory response,[35] Hydro One stated that economies of scale and efficiencies gained from longer transmission lines like the Project have the potential to produce a lower cost per km of line, compared to similar designed and scoped transmission circuits of a shorter length. Later in its Argument-in-Chief, Hydro One made similar comments.[36]

[31] Interrogatory response to OEB staff 12(b).
[32] EB-2023-0298.
[33] EWT project in-service year was 2022, while the Project has an in-service year of 2025 (Phase 1) and 2027 (Phase 2).
[34] Exhibit B, Tab 7, Schedule 1, p. 8.
[35] Interrogatory response to OEB Staff 13(a).
[36] Argument-in-Chief, p. 18.

2. Hydro One's justifications for higher costs are generally reasonable, but additional information would have been helpful

The Project's higher costs are driven by increases in commodity prices and manufacturing costs and labour market shortages. OEB staff calculates that the line portion of the Project cost is $144 million[37] higher than the EWT project when considering the cost per km analysis.

Hydro One noted that from January 2021 to January 2022, the price of copper has increased by 27.1%, aluminum has increased by 41.6% and steel has increased by 111.6%. In an interrogatory response,[38] Hydro One stated that although significant cost fluctuations that occurred during Covid-19 are now stabilizing, escalating manufacturing costs are applying an upward pressure to costs.

Although OEB staff accepts Hydro One's rationale for the Project costs being higher than previous comparable projects, OEB staff is of the view that the proceeding would have benefited from more information to support its reasoning. Additional information could have been included, such as trend analysis of equipment costs (i.e., resulting from increasing commodity prices) and manufacturing costs (i.e., resulting from supply shortages and a highly competitive labour market).

3. The Project's contingency estimates appear to be high

The estimated contingency cost for the line and station portions of the Project is $123.6 million. In a response to interrogatories,[39] Hydro One provided the following table comparing the Project's contingency estimates to other recent Leave to Construct applications with significant budgets. As can be observed, the Project's contingency estimates are significantly higher than the comparators.

Table 3: Contingency Cost Comparison

	Waasigan Project Phase 1	Waasigan Project Phase 2	Chatham Lakeshore Project	East-West Tie Line
Line Cost	10.5%	9.5%	8.9%	6.7%
Station Cost	11.2%	12.3%	4.6%	12.2%

Hydro One stated that the contingency estimates consider risks related to market

[37] $144 million = ($2.6 million / km - $2.2 million / km) x 360 km.
[38] Interrogatory response to OEB Staff 11.
[39] Interrogatory response to OEB Staff 7.

volatility, commodity prices, availability of resources, production escalation costs and labor rate escalation that will fluctuate over the execution the Project. Hydro One stated that these risk factors are also more significant than was typical prior to Covid-19 which it stated was not a factor in many of the comparator projects that had estimates completed prior to the Covid-19 pandemic.

OEB staff is of the opinion that although Hydro One provided some information to support the higher contingency costs, a more detailed explanation comparing the contingency cost with the comparators (Chatham by Lakeshore and EWT projects) would have been helpful. Based on the evidence, it is unclear to OEB staff how pre and post-Covid-19 pandemic conditions have contributed to significant changes to risk factors, and thereby, the contingency cost. OEB staff also notes that similar to the Project, the Chatham Lakeshore Project was undertaken post-Covid-19.

OEB staff submits that the contingency cost estimates for the line portion of the Project should be reviewed in the Project's cost-based transmission revenue requirement proceeding. In that proceeding, OEB staff suggests that any incurred contingency costs be provided in the prefiled evidence.

4. **The proposed New Overhead Capitalization Methodology should be tested in the Project's first cost-based rates application**

Please see section 2.4 for details.

2.4 New Overhead Capitalization Methodology Approach

For the Project, Hydro One noted that a fixed price Engineering, Procurement and Construction (EPC) execution methodology has been selected to best define and manage project scope, schedule and risk, while also providing cost predictability in the delivery of a project of this magnitude.[40] Hydro One further noted that the use of a refined overhead capitalization methodology is an outcome of the approach Hydro One is taking to develop and construct projects, and will provide cost benefits, and increased cost certainty to the Project.[41]

Hydro One stated that it is using an Early Contractor Involvement (ECI) delivery model for the Project.[42] The ECI delivery model engages the services of an external engineering firm and the services of EPC contractors (ECI-EPC). The ECI-EPC contractor performs many of the development functions that under the standard Hydro

[40] Argument-in-Chief, p. 18.
[41] Argument-in-Chief, p. 19.
[42] Exhibit B, Tab 7, Schedule 1, p. 5; Argument-in-Chief, p. 19.

One EPC delivery model would be performed internally by Hydro One.

The overhead allocation rate for ECI-EPC projects is lower to reflect a reduced amount of Hydro One Common Corporate functions support required by ECI-EPC projects, compared to standard Hydro One transmission projects.[43] Hydro One stated that indirect overhead costs allocated to the Project are Common Corporate Costs[44] and are charged to capital projects through an overhead capitalization rate.

Hydro One engaged Atrium Economics to review Hydro One's current overhead capitalization methodology to determine if adjustments were warranted for the new execution model.[45] Atrium Economics recommended that Hydro One use a blended overhead rate that would be determined by the weighted average portion of a project's type/source of costs, specifically the two differentiated types of project costs being:[46]

i) ECI-EPC costs, which do not rely as heavily on Hydro One's corporate support functions; and
ii) Non-ECI-EPC costs, that should attract the standard Transmission overhead rate as they rely on Hydro One's corporate support functions.

Hydro One stated that a five-year weighted average overhead rate of 3.0% (rounded) will be applied to the Project's annual capital expenditures,[47] with the derivation of the rate of 3.0% shown in Table 4 below.

[43] Argument-in-Chief, p. 19.
[44] Exhibit B, Tab 7, Schedule 1, p. 2.
[45] Exhibit B, Tab 7, Schedule 1, p. 6.
[46] Argument-in-Chief, p. 20.
[47] Interrogatory response to OEB Staff 21; Exhibit B, Tab 7, Schedule 1, p. 7.

Table 4: Derivation of Blended Overhead Capitalization Rates

	2023	2024	2025	2026	2027	Average Rounded	Average Rounded Up
Standard Transmission Overhead Capitalization Rates	8.1%	7.7%	7.0%	7.3%	7.9%		
Weighting	20.5%	20.5%	20.5%	20.5%	20.5%		
Weighted Average - Tx Overhead Capitalization Rates	1.7%	1.6%	1.4%	1.5%	1.6%		
ECI-EPC Projects Overhead Capitalization Rates	1.2%	1.2%	1.2%	1.2%	1.2%		
Weighting	79.5%	79.5%	79.5%	79.5%	79.5%		
Weighted Average - ECI-EPC Overhead Capitalization Rates	1.0%	1.0%	1.0%	1.0%	1.0%		
Blended Overhead Capitalization Rates	**2.6%**	**2.6%**	**2.4%**	**2.5%**	**2.6%**	**2.5%**	**3.0%**

Hydro One stated that the new approach is utilizing the same methodology that was agreed to by parties and accepted by the OEB in Hydro One's Joint Rate Application (JRAP) proceeding (EB-2021-0110).[48] However, by using the refined overhead capitalization methodology outlined above, Hydro One stated that it lowers the impact to the Project budget by approximately $60 million (i.e., not charging the Project for components of Hydro One overhead that are being performed by the ECI-EPC contractor.)

Hydro One concluded that the use of the overhead capitalization rate is appropriate, provides ratepayer and project cost benefit, and is consistent with Hydro One's existing OEB approved cost allocation methodology.[49]

Submission

OEB staff can neither support nor dispute the proposed new overhead capitalization methodology approach. OEB staff submits that the review of the proposed new overhead capitalization approach should be conducted by the OEB as part of the Project's first cost-based rates application (which is expected to be filed in January 2025), rather than in the current proceeding. In the Project's first cost-based rates

[48] Argument-in-Chief, p. 21.
[49] Argument-in-Chief, p. 22.

application, OEB staff recommends that the following six points be addressed:

1. The new approach is proposed to be a precedent.
2. The new approach is proposed to have a material impact.
3. There are implications on the new approach based on the regulatory accounting standard used.
4. There are implications on the selected date to apply the new approach.
5. It is unclear whether the difference between the legacy overhead capitalization methodology and the new approach is being tracked in a deferral or variance account.
6. The new approach is a rates issue and should be tested by a number of additional ratepayer groups, in conjunction with OEB staff.

1. The new approach is proposed to be a precedent.

OEB staff submits that since this new approach is proposed to be a precedent for a portfolio of significant transmission system expansion projects,[50] as well as for Hydro One's broader transmission and distribution businesses (as applicable),[51] it is important that this new approach be appropriately tested in the Project's first cost-based rates application.

2. The new approach is proposed to have a material impact.

Hydro One stated that utilizing the standard delivery model overhead (instead of the proposed new approach) would increase the total cost estimate of the Project by approximately $58.9 million.[52] However, this is only a portion of the impact that Hydro One expects the methodology to provide.

Hydro One further stated that the impact of rounding the overhead rate from just over 2.5% to 3.0% is approximately $5 million.[53] Hydro One also stated that if the OEB does not approve the new approach, Hydro One will continue to utilize the existing overhead capitalization methodology.[54]

OEB staff submits that since this new approach has a material impact on the Project, it is also important that this new approach be appropriately tested in the Project's first cost-based rates application.

OEB staff submits that Hydro One should provide a net present value (NPV) analysis in

[50] Interrogatory response to OEB Staff 30.
[51] Interrogatory response to OEB Staff 21.
[52] Interrogatory response to OEB Staff 30.
[53] Interrogatory response to OEB Staff 20.
[54] Interrogatory response to OEB Staff 27.

the Project's first cost-based rates application, showing the impact on the Project (i.e., if the Project remains viable), in the event that the OEB does not approve the new approach and the above-noted $58.9 million may be added to the Project.[55]

3. **There are implications on the new approach based on the regulatory accounting standard used.**

Capitalization of indirect overheads is generally allowed under USGAAP, but not under Modified International Financial Reporting Standards (MIFRS). Most Ontario utilities use MIFRS for regulatory reporting purposes. OEB staff also notes the applicability of a recent OEB decision in the Enbridge Gas Inc. proceeding which disallowed the capitalization of indirect overheads over a set period.[56] Enbridge Gas Inc. also uses USGAAP for its regulatory accounting standard.

Hydro One stated that the OEB has previously granted approval for Hydro One to apply USGAAP for regulatory purposes through to 2027, and that the Project will be completed by the end of 2027.[57]

OEB staff submits that since Hydro One may be required to switch its regulatory accounting standard from USGAAP to MIFRS in the future, thereby no longer being able to capitalize indirect overheads, it is important that more discovery be brought forward in the Project's first cost-based rates application. OEB staff also notes that the continued use of USGAAP as the regulatory reporting basis does not provide a blanket approval from the OEB for the capitalization of indirect overheads.

OEB staff also submits that Hydro One's position that the Project will be completed by the end of 2027 (and that the OEB approved Hydro One's use of USGAAP for regulatory purposes for the 2023-2027 period) is irrelevant to the discussion of the implications of the regulatory accounting standard to be used. This is given that the Project may not be completed by the end of 2027 and also that Hydro One's new approach is proposed to be a precedent for other Hydro One expansion projects which will run past 2027.[58]

As Hydro One did not adequately address OEB staff's concerns, OEB staff submits that Hydro One, in the Project's first cost-based rates application, should for the 2019 to 2027 period:[59]

[55] Hydro One should provide a live spreadsheet (e.g., with formulas intact) for its NPV analysis, as well describe all assumptions made with reasons.
[56] EB-2022-0200, Enbridge Gas Inc., Decision and Order, December 21, 2023, pp. 98 & 99.
[57] Interrogatory response to OEB Staff 29.
[58] Interrogatory response to OEB Staff 25.
[59] As also noted in Interrogatory response to OEB Staff 29.

- On a best-efforts basis, explain, identify, and quantify indirect costs (including indirect overheads) that are eligible for capitalization under USGAAP but not under MIFRS.
- Outline the impact on the Project if the OEB does not allow Hydro One to capitalize indirect overheads as requested and recover such indirect overheads on a capitalized basis.
- Track the indirect costs that are currently capitalized under USGAAP, but not permitted under MIFRS, in a deferral and variance account (DVA) (e.g., Accounting Policy Changes Deferral Account or the ATP Account) and discuss whether such a DVA should be established for the Project.

4. There are implications on the selected date to apply the new approach.

Hydro One stated that it implemented the adjusted overhead rate in Q3 2023.[60] Hydro One stated that it is not implementing any retroactive adjustments on the prior $47.4 million of capital expenditures which attracted Hydro One's general standard overhead rate.[61] That said, Hydro One noted that prior to 2023, ECI-EPC project costs were not a material component of the overall Hydro One work program.[62]

OEB staff submits that further discovery is required in the Project's first cost-based rates application as to which date the OEB should approve the application of the new approach, given that the impacts are material to Hydro One. OEB staff is of the view that the $47.4 million of capital expenditures relating to the Project which continued to attract the general standard overhead rate could inflate these capital costs.

5. It is unclear whether the difference between the legacy overhead capitalization methodology and the new approach is being tracked in a deferral or variance account.

For each year 2019 to 2023, OEB staff requested Hydro One to explain whether it will track the difference as credits (i.e., a refund to customers) between the legacy overhead capitalization methodology and the new approach until the next rebasing for the Project in a new DVA (e.g., Accounting Policy Changes Deferral Account), or plans to track the differences in the ATP Account.[63] OEB staff noted that the amount of indirect costs applied to capital expenditures would decrease, given the proposed decline in the

[60] Interrogatory response to OEB Staff 24.
[61] Interrogatory response to OEB Staff 24: Hydro One stated that this was disclosed to the OEB in the most recent Waasigan OEB Report April 2023 to September 2023. OEB staff notes the reference in EB-2019-0151 – Waasigan Transmission Line Project – Bi-Annual Report, October 20, 2023, p. 7, Table 1, Column B.
[62] Interrogatory response to OEB Staff 24.
[63] Interrogatory response to OEB Staff 25.

overhead capitalization rate by using the new approach.

Hydro One did not adequately address OEB staff's concerns, as it simply stated that it will track Project capital costs, inclusive of capitalized overheads (i.e., those resulting from the new approach) in the ATP Account. OEB staff submits that the issue of whether the above-noted credits should be recorded in a new DVA or the ATP Account, as well as the associated timing, should be further explored in the Project's first cost-based rates application, given the materiality of these credit amounts.

6. **The new approach is a rates issue and should be tested by a number of additional ratepayer groups, in conjunction with OEB staff.**

OEB staff submits that the new approach is better considered in the Project's first cost-based rates application, given that it is a rates issue and not an issue typically addressed in Leave to Construct applications.

OEB staff agrees with Hydro One's statement in interrogatories[64] that for the Project's first cost-based rates application, Hydro One should engage an independent expert to undertake a review of the new approach, with the filing of the expert's report on the record of that proceeding. OEB staff is of the view that it would be helpful to the OEB if alternatives would be considered in that expert's report, including an analysis of alternate overhead capitalization methodologies used by other utilities in North America, including a blended capitalization rate methodology.[65] OEB staff also recommends that details of Hydro One's annual evaluations of the new approach (as suggested by Hydro One in interrogatories) should also be filed on that record.[66]

OEB staff notes that many of the ratepayer groups that typically are involved in Hydro One's cost-based rates applications are not represented in the current proceeding. OEB staff submits that it would be appropriate to give a broader range of ratepayer groups the opportunity to test the evidence brought forward for the proposed new approach in the Project's first cost-based rates application.

2.5 Consumer Impacts

The application states that the Project will increase the region's capability of meeting

[64] Interrogatory response to OEB Staff 21.
[65] Interrogatory response to OEB Staff 28: OEB staff noted that the Atrium Economics Report did not include any alternatives to that proposed for the Project in this application, or an analysis of alternate overhead capitalization methodologies used by other utilities in North America (as well as those of Hydro One's Ontario industry peers), including a blended capitalization rate methodology. Hydro One stated that the Atrium Economics Report is an extension of the industry and best practice analysis conducted initially as part of the development of the Black and Veatch Report filed in Hydro One's JRAP.
[66] Interrogatory response to OEB Staff 26.

load demand including the region's summer supply capacity needs. The proposed Project will release constraints on transfers into the region and serve as a steppingstone for additional load growth to meet future needs.

The stations which connect the new circuit, Lakehead TS, Mackenzie TS and Dryden TS, are network stations. As a result, Hydro One proposes that the new circuits be included in the Network Pool as they directly connect these stations and meet the needs identified by the IESO.

The Project is not associated with any specific load increase or customer load application, and hence, will not require customer contributions.

Hydro One estimated a potential growth of approximately 206 MW resulting in $13.3 million in annual incremental network revenue over a 25-year evaluation period using 2023 Uniform Transmission Rates.

Hydro One estimated that the Project will change the network connection pool revenue requirement once it is incorporated into the transmission rate base when the Project is in-service (Phase 1 at December 15, 2025 and Phase 2 at December 15, 2027). Over a 25-year time horizon, Hydro One anticipates that the Project will increase the 2023 OEB-approved network rate of $5.37 kW/month to $5.71 kW/month by year four.

Hydro One estimated that the project will increase the typical residential customer bill by $0.56 per month or 0.41%, amounting to an increase of approximately $6.68 per year.

Submission

OEB staff submits that Hydro One's proposed allocation of Project costs to the network connection rate pool is appropriate. OEB staff takes no issue with Hydro One's position that no customer contribution is required.

Besides the concerns noted in section 2.3 Project Costs, OEB staff submits that the consumer impacts of the Project are appropriate given the need for the Project and the relatively modest impact on customers, as Hydro One's evidence suggests.

2.6 Reliability and Quality of Service

The IESO's Final System Impact Assessment (SIA) concluded that the Project is expected to have no material adverse impact on the reliability of the integrated power system, provided that all requirements in the SIA report are implemented.

In the SIA report, the IESO stated that it recommended that the design of the two new 230 kV circuits between Lakehead TS and Mackenzie TS be revised such that they are configured on double-circuit towers for their entire length and not utilize any quadruple-circuit towers. The SIA report noted that the region is prone to adverse weather impacts, which pose a risk when there are multiple short circuits that occur simultaneously due to tower sharing. This revision to the design will support reliability and resilience in the area. The SIA report also recommended specific equipment replacements and reconfiguring transmission elements at some of the stations.

Hydro One's Final Customer Impact Assessment (CIA) concluded that the resulting voltage changes on area high-voltage and low-voltage buses are within planning limits. The CIA report stated that the proposed Project has a relatively small impact on short-circuit levels in the area and recommended that impacted customers review the short circuit change on their facilities.

Submission

OEB staff does not have any concerns about the reliability and quality of service associated with the Project, considering Hydro One's evidence and the conclusions of the IESO's SIA and Hydro One's CIA.

2.7 Land Matters

The total route length of Phase 1 and Phase 2 of the proposed corridor for the Project is approximately 190 km and 170 km, respectively, and 46 metres wide. The corridor will parallel an existing transmission line. Hydro One proposed to use this existing right-of-way to the extent possible which is consistent with *Ministry of Municipal Affairs and Housing Provincial Policy Statement*, *2020* under the *Planning Act*. The new transmission corridor passes through primarily Crown, municipal and privately held lands.

The proposed corridor for the Project is within the traditional territories of the Treaty #3 and Robinson-Superior First Nations and traverses the Northwestern Ontario Métis Community and Northern Lake Superior Métis Community. The Crown has a Duty to Consult, and where appropriate, accommodate Indigenous peoples whenever a Crown decision or activity could impact established or asserted Aboriginal and Treaty rights. The Ministry of Energy determined that Hydro One's proposed Project may have the potential to affect First Nation and Métis communities who hold or claim Aboriginal or Treaty Rights protected under Section 35 of *Canada's Constitution Act,1982*.

Hydro One stated that it worked with Indigenous Communities to develop a consultation plan which identified its commitments and activities for Indigenous engagement on the Project and the need for meaningful engagement and relationships with the individual Indigenous communities, to understand and address any concerns over impacts to

Section 35 rights.

For non-Indigenous land rights, Phase 1 will require Hydro One to acquire land rights from approximately 164 directly impacted property owners (156 privately held properties, 5 Crown properties, 1 municipally held property and 2 railway crossings).

Phase 2 of the Project will require Hydro One to acquire land rights from approximately 97 directly impacted property owners (78 privately held properties, 1 federally held property, 7 Crown properties, 7 municipally held properties, 2 Ontario Power Generation properties and 2 railway crossings).

In both phases, the majority of properties will require Hydro One to acquire easement or fee simple corridor at the property owner's election. A small number of properties will have dwellings and or major outbuildings within the new corridor proposed for the Project. Hydro One stated that it will work with directly impacted property owners to negotiate amicable voluntary agreements, which may include full property buyouts, at the property owner's election.

In addition, Phrase 1 and Phase 2 of the Project will require Hydro One to acquire consent from approximately 260 and 238 existing permit holders, respectively, consisting of 32 and 31 unique permit holders, respectively, who have an interest in unpatented Crown Lands. The existing permits intersect the current proposed Project corridor and the large majority are mining claims. Hydro One stated that it will work with the appropriate permit holders to obtain consent for the disposition of their surface rights along the current proposed Project corridor.

The new Project corridor will include a combination of the following land rights requirements:

- Land Use Permits on unpatented Crown Lands (new land rights required)
- Easement or fee simple rights on private, municipally owned, provincially owned and federally owned properties (new land rights required)
- Rail crossing agreements (new land rights required)
- Temporary access and/or construction rights on provincially owned, unpatented Crown and private properties for access roads, temporary work headquarters, laydown areas, and material storage facilities (new land rights required)

The table below lists the different land rights agreements that Hydro One has stated may be required, including details on the extent to which the forms of agreement have previously been approved by the OEB in prior proceedings.

Table 5: Forms of Land Rights Agreements and Prior OEB Approvals

Form of Agreement	Past OEB Approval
Agreement for Temporary Rights	Prior approval in EB-2022-0140, no substantive changes proposed
Damage Claim Agreement/Waiver	Prior approval in EB-2022-0140, no substantive changes proposed
Compensation and Incentive Agreement - Easement	Prior approval in EB-2022-0140, no substantive changes proposed
Option to Purchase – Fee Simple	Prior approval in EB-2022-0140, no substantive changes proposed
Compensation and Incentive Agreement – Fee Simple	Prior approval in EB-2022-0140, no substantive changes proposed
Off Corridor Access	Prior approval in EB-2022-0140, no substantive changes proposed
Option to Purchase a Limited Interest – Easement	Prior approval in EB-2022-0140, minor changes proposed
Option to Purchase a Limited Interest – Easement with a Voluntary Buyout Offer	Prior approval in EB-2022-0140, minor changes proposed
Early Access Agreement	New agreement

Submission

OEB staff has reviewed the proposed forms of agreements and has no concerns. Many of the agreements are generally consistent with the agreements approved by the OEB through previous proceedings.[67] OEB staff notes that the forms of agreement serve only as the initial offer to landowners and may not reflect the final agreement that is agreed to between the parties.

Hydro One confirmed that all impacted landowners have the option to receive independent legal advice regarding the land agreements, and that it would commit to reimbursing those landowners for reasonably incurred legal fees associated with the review and completion of the necessary land rights including the new form of agreement for early access.[68]

2.8 Conditions of Approval

The OEB Act permits the OEB, when making an order, to impose such conditions as it considers proper. The OEB has established a set of standard conditions of approval for transmission Leave to Construct applications.

[67] EB-2022-0140, Decision and Order, November 24, 2022 (Chatham by Lakeshore Project).
[68] Interrogatory response to OEB Staff 15(a-b).

Submission

OEB staff proposes that the standard conditions of approval be placed on Hydro One. The proposed conditions have been approved by the OEB in prior leave to construct applications. Hydro One has confirmed that it agrees with the standard conditions of approval.[69]

~All of which is respectfully submitted~

[69] Interrogatory response to OEB Staff 17(a).