McCarthy Tétrault LLP
Suite 4000
421-7th Avenue S.W.
Calgary AB T2P 4K9
Canada
Tel: 403-260-3500
Fax: 403-260-3501

Gordon M. Nettleton
Direct Line: 416-601-7509
Email: gnettleton@mccarthy.ca

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Filed on RESS

Ritchie Murray
Acting Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

CC: RegulatoryAffairs@hydroone.com

Dear Mr. Murray:

Re: Hydro One Networks Inc. ("HONI") Interrogatory Responses OEB File Number: EB-2025-0290

We are legal counsel to HONI, who is the Applicant in the above-referenced proceeding. In accordance with Procedural Order No. 2, please find attached a copy of interrogatory responses provided by HONI in the above-noted proceeding to questions received from the Ontario Energy Board ("**OEB**") Staff, and Futecan Canada Inc. ("**Futecan**").

Intervenor interrogatory responses have been assigned Exhibit I and have been addressed in the following Exhibit order:

Exhibit	Tab	Intervenor
I	1	OEB
I	2	Futecan

In accordance with OEB filing requirements and policies, components of the interrogatory responses have been filed with redactions given the personal nature of the information disclosed therein. HONI confirms that all redacted versions of documents filed in support of HONI's interrogatory responses do not disclose any personal information under the *Freedom of Information and Protection of Privacy Act*. Furthermore, HONI has, pursuant to Rule 10 of the OEB's Rules of Practice and Procedure and the OEB's Practice Direction on Confidential Filings dated December 17, 2021, requested confidential treatment of certain information contained in its response to OEB Staff interrogatory 8 Attachment 1, and OEB Staff interrogatroy 11 (f),(g),(i),(j)& (k).

Additionally, in accordance with subsection 6.1.2, 6.1.4 and 6.1.7 of the Practice Direction and subsections 10.01 and 10.02 of the Rules, HONI has proposed that the confidential versions of its responses to OEB staff interrogatories OEB Staff-8(Attachment 1) and OEB Staff 11(f),(g),(i),(j),and (k) be disclosed to only counsel for OEB Staff from whom the OEB accepts a Declaration and Undertaking

An electronic copy of these responses has been submitted using the OEB's Regulatory Electronic Submission System.

Yours very truly,

McCarthy Tétrault LLP

Gordon M. Nettleton
Partner | Associé

OEB STAFF INTERROGATORY - 01

Reference:
Exhibit B-2-1, Pages 1-2

Preamble:
In the reference, Hydro One stated that the Project will construct approximately 18.5 km of new transmission line inclusive of 11.5 km of new 230 kV double circuit transmission line and 8 km of a new triple circuit transmission line initiating from Abitibi Consolidated Junction to Crowland TS. Hydro One also noted the length of the two double circuit line sections:

- Abitibi Consolidated Junction to Allanburg TS: 3.5 km
- Michigan Junction to Crowland TS: 7 km

Interrogatory:
a) Please review and correct the total number of km of the double circuit transmission line referenced in the Preamble (11.5 km).

Response:
a) The 230 kV double circuit transmission should be reflected as 10.5 km. Exhibit B, Tab 2, Schedule 1 will be updated in the Application to reflect this change.

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OEB STAFF INTERROGATORY - 02

Reference:
1. Exhibit B-2-1, Pages 1-2
2. Exhibit C-1-1, Pages 1-2

Preamble:
References 1 and 2 describe the three segments (A, B, and C) of the line component of the Project.

Interrogatory:
a) Does Reference 2 contain a typo on Page 2, Line 3, where it should say "Segment B", instead of "Segment C"?

b) For Segment B, between Allanburg TS and Michigan JCT, please confirm whether there are two 115 kV transmission circuits (D3A and A3C) being dismantled, and being replaced with one new 115 kV transmission circuit, in addition to two new 230 kV transmission circuits?

c) Please explain how two existing 115 kV circuits in Segment B are being consolidated into one.

Response:
a) Yes, Page 2, Line 3 of Exhibit C, Tab 1, Schedule 1 does contain a typo. The reference should read "Segment B" rather than "Segment C". An update of the Schedule has been included as Attachment 1 of this response.

b) Confirmed. For Segment B, between Allanburg TS and Michigan JCT, there are two 115 kV transmission circuits (D3A and A3C) being dismantled. D3A is a dedicated line to a customer and A3C is currently idle. They are both being replaced with one new 115 kV transmission circuit, in addition to two new 230 kV transmission circuits.

c) Though a 115 kV circuit, A3C is currently an idle circuit that will be demolished. D3A is a dedicated circuit that will be first maintained with a temporary bypass line while the existing double circuit 115kV towers are being demolished, then replaced ultimately with the triple circuit arrangement (two 230kV circuits and one 115kV circuit).

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OEB STAFF INTERROGATORY - 03

Reference:

1. Exhibit B-2-1, Page 2
2. Exhibit C-1-1, Page 1

Preamble:

References 1 and 2 refer to Segment C (Michigan JCT to Crowland TS) of the line component of the Project. Reference 1 suggests that 7 km of an idle 115 kV transmission line corridor will be repurposed. Reference 2 suggests that 5.5 km of idle corridor will be repurposed and 1.5 km will be net-new corridor.

Interrogatory:

a) Please clarify the inconsistency between the descriptions.

Response:

a) To clarify, approximately 5.5km of Section C will re-use an existing corridor paralleling A6C/A7C to the south, and 1.5km will be a net new corridor paralleling A6C/A7C to the north, with approximately 30m width. 1.5km of the existing corridor could not be utilized for the new transmission line.

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OEB STAFF INTERROGATORY - 04

Reference:
Exhibit B-2-1, Attachments 3-4

Preamble:
The Reference provides a simplified schematic diagram for the two new 230 kV circuits.

Interrogatory:
a) Please clarify whether there will be any taps off the two new 230 kV circuits.

b) Please confirm whether the new Crowland TS will have a connection to the 115 kV network.

c) Please provide single line diagrams, showing all line segments and connected customers/stations, before and after the completion of this Project, for circuits D3A, A3C, A6C, A7C, A1C, and A1T.

Response:
a) As depicted in Attachment 3 and 4 of Exhibit B, Tab 2, Schedule 1, there will be a 230kV tap for Crowland TS.

b) Crowland TS currently has 115kV switching capability used for operational flexibility that supports 115kV loads located south of Crowland TS. This will be maintained to allow the transfer of load customers onto the adjacent circuit during an upstream outage. All 115kV transformation at Crowland TS will be removed.

c) Please refer to Attachment 1 of this Schedule for a copy of the requested diagrams.

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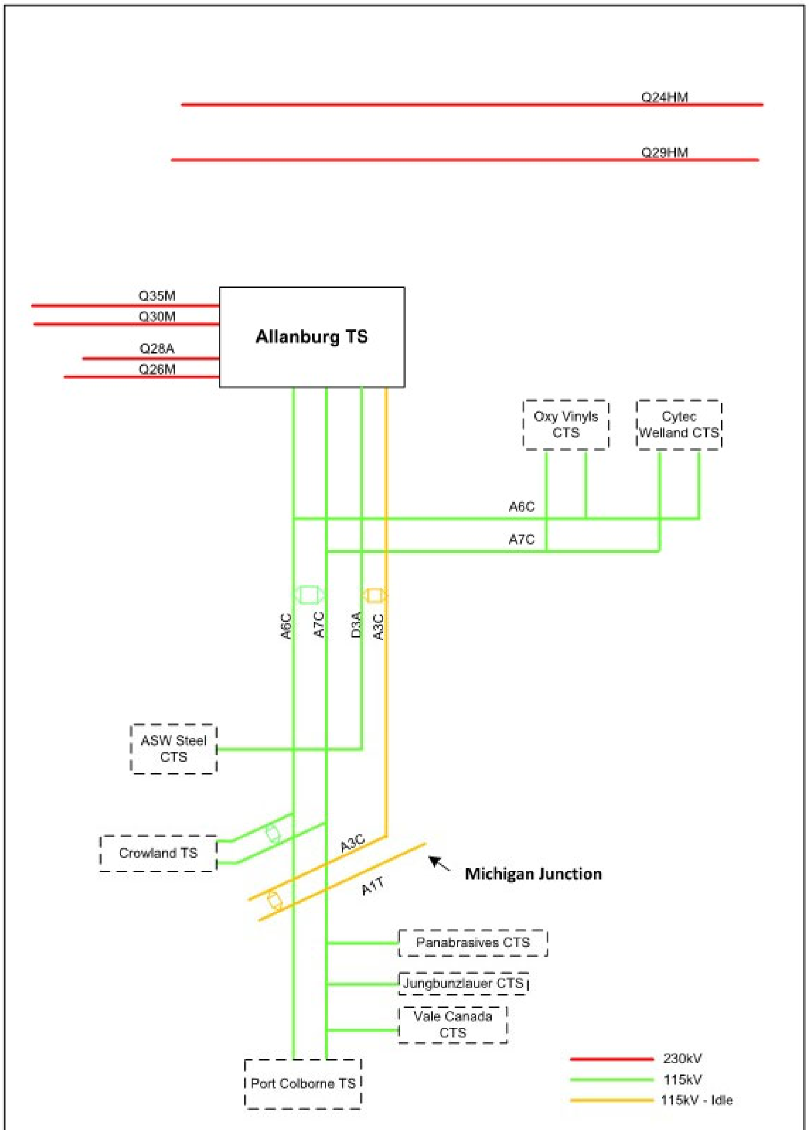
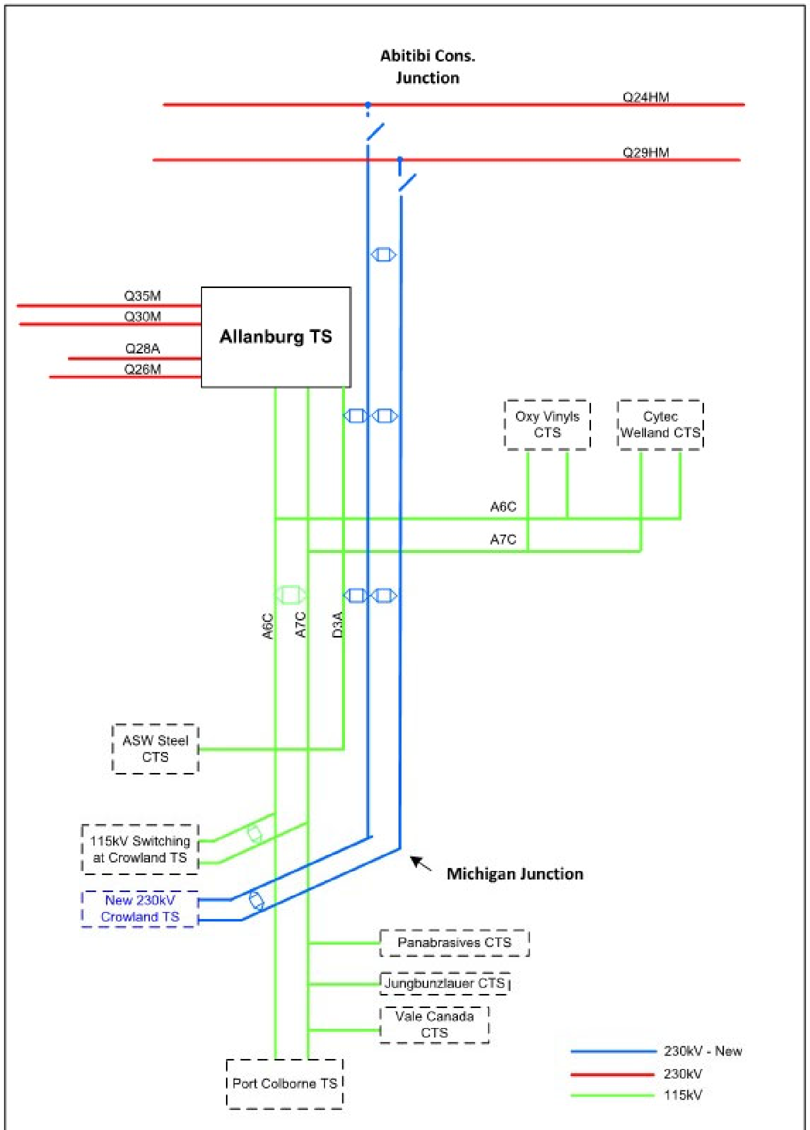
Attachment 1



Existing – Before Completion of Project



Proposed – After Completion of Project

OEB STAFF INTERROGATORY - 05

Reference:
Exhibit B-3-1

Preamble:
In the reference, Hydro One stated that the Project is needed to increase the supply capacity between Abitibi Consolidated Junction and Crowland TS to support the continued load growth in the Niagara area and improve reliability in the area.

Attachment 1 of Exhibit B-3-1 also stated that since the 2022 Niagara Integrated Reginal Resource Plan (IRRP), a number of System Impact Assessments (SIA) have been received for new load connection requests that are impactive to the need for the Project.

Interrogatory:
a) Please provide five years of historical demand information (MW) for the Niagara area.

b) Please provide demand forecast information (MW) consistent with the forecast used in the relevant planning assessment that recommended the Project.

c) How many new load customers have indicated to Hydro One that they plan to connect, and what is the amount of capacity (MW) they will require to meet their planned energy needs?

d) How many new generators have indicated to Hydro One that they plan to connect to the proposed system and what is the related supply capacity (MW)?

Response:
a) The five year historical non-coincident demand (MW) for stations supplied by Hydro One in the Niagara area is below.

	2020	2021	2022	2023	2024	2025
Niagara Region (MW)	964	909	956	949	1026	1078

b) The latest non-coincident demand forecast information that recommended the Project is provided in the Regional Infrastructure Plan prepared by the Niagara Working Group for the 2nd Regional Planning cycle. This information is provided at Appendix C of Exhibit H, Tab 1, Schedule 1, Attachment 1.

c) Several load customers have expressed interest in connecting; however, as of at the time of filing this application, none have committed to a new 230 kV connection. Notwithstanding the absence of committed connections, please refer to Exhibit B, Tab 3, Schedule 1, Attachment 1 where the IESO has detailed the following with respect to a load forecast update that underpins the need for the Project:

> Since the 2022 Niagara IRRP, a number of SIAs have been received for new load connection requests that are impactive to the need for the Project, totalling over 700 MW of step changes in demand for the area. A subset of these connection requests overlap with the projects included in the 2022 Niagara IRRP -140 MW in the reference and 210 MW in the high forecast scenario. The remaining approximately 500 MW represents additional unanticipated load growth relative to the IRRP forecasts. Of the SIAs received, approximately 300 MW of load connections have been approved to date with in-service dates ranging from 2024 to 2027. In addition, there have been discussions with other potential load applicants in the Port Colborne area, which have not yet proceeded to the SIA phase. The Project is the first reinforcement required to provide additional points of connection in the area. The Niagara Bulk Plan, outlined in Section 5, is needed to determine further bulk reinforcement requirements to enable additional transmission supply in the region.[1]

d) No generators have expressed any interest in connecting to the proposed system.

[1] Exhibit B, Tab 1, Schedule 1, Attachment 1

OEB STAFF INTERROGATORY - 06

Reference:

Exhibit B-3-1, Pages 1-2

Preamble:

The Reference states that “Specifically, the current protection scheme is insufficient to provide adequate protection for the newly added 230 kV circuit” before recommending installing inline breakers and adding a new sectionalizing station.

Interrogatory:

a) Please explain how the Project will provide adequate protection for the two new 230 kV circuits before the planned future Crowland SS is constructed.

Response:

a) For context, the final IESO System Impact Assessment (SIA) provided at Attachment 1 of Exhibit F, Tab 1, Schedule 1 concluded that:

> “…***the Project is expected to have no material adverse impact on the reliability of the integrated power system*** *and recommends that a Notification of Conditional Approval be issued.”*[1] *(emphasis added)*

The IESO SIA conclusions are predicated on the Project scope that details:

> “*To allow proper protection of Q29HM and Q24HM circuits* ***after the project,*** *Hydro One Networks Inc. will sectionalize the Q29HM and Q24HM circuits by adding an inline breaker on each circuit about 14 km away from Beck 2 TS, west of the connection point for the project.”*[2]*(emphasis added)*

The forecast in service date for the Project is August 14, 2029, as outlined in Exhibit B, Tab 11, Schedule 1. The expected in-service date for the planned future Crowland SS is November 30, 2029.

With the present short circuit levels at Beck-2 TS, Middleport TS and Beach TS, a maximum of 113 MVA per circuit can be added to Q24HM or Q29HM circuits without requiring the installation of the future proposed Crowland SS. Once these thresholds are exceeded, however, Crowland SS is required. It is unknown when loading on the 230 kV circuits will exceed this threshold “with unanticipated load growth relative to

[1] Exhibit F, Tab 1, Schedule 1, Attachment 1 – p. 7
[2] Exhibit F, Tab 1, Schedule 1, Attachment 1 – p. 7

the IRRP forecasts … *Of the SIAs received, approximately 300 MW of load connections have been approved"* [3] and therefore, despite being a distinct and separate project, the full costs associated with Crowland SS have been included in the economic evaluation provided at Exhibit B, Tab 9, Schedule 1. Similarly, the full loading that could be connected once Crowland SS is in-service without any other transmission line reinforcements as determined by draft connection impact assessments completed by the IESO of up to 180MW has similarly been included in the economic evaluation assessment.

In concert with the above and during the construction of both projects, the load from the 115kV station will be slowly transferred within the adequate protection margins of the current protection scheme to the new 230kV station until the planned future Crowland SS is in service.

[3] Exhibit I, Tab 3, Schedule 1, Attachment 1

OEB STAFF INTERROGATORY - 07

Reference:

1. Exhibit B-5-1
2. Chapter 4 Filing Requirements, section 4.3.2.5

Preamble:

As required in Reference 2, applicants for LTC projects that derive from a regional plan must demonstrate that alternatives to address regional needs, including conservation and demand management (CDM) measures and non-wire alternatives have been appropriately considered in developing the proposed project.

Interrogatory:

a) Have the above noted alternatives been considered in developing the proposed Project? If yes, please briefly discuss those alternatives. If no, please explain why.

b) Reference 1 states that the transmission line loss analysis is available upon request. Please provide the transmission line loss analysis.

Response:

a) Yes, non-wires alternatives were considered in establishing the need for the Project. As detailed in Exhibit B, Tab 3, Schedule 1, the need for the Project has been identified in multiple regional planning documents being explicitly identified in the IESO's 2022 Niagara Integrated Regional Resource Plan (IRRP) and the 2023 Niagara Regional Infrastructure Plan (RIP). These plans have been attached for reference at Exhibit H, Tab 1, Schedules 1 and 2 of the Application. Please refer to Section 7.1 of Exhibit H, Tab 1, Schedule 1, Attachment 2 for options considered during the IRRP which ultimately determined that the Project was the best solution to address the needs of the area.

b) Hydro One undertook an analysis of the conductor size alternatives that would, a) meet the supply needs in the Allanburg area and, b) optimize transmission line losses based on the expected load scenario. The conductor alternatives evaluated were:

   1. Alternative 1 – 1192.5 kcmil ACSR conductor
   2. Alternative 2 – 1443.7 kcmil ACSR conductor
   3. Alternative 3 – 1433.6 kcmil ACSS conductor

   The results of the NPV sensitivity analysis are provided below.

NPV Sensitivity Analysis of Alternatives

	Alt. #1 (1192.5 kcmil ACSR)	**Alt. #2** (1443.7kcmil ACSR)	**Alt. #3** (1433.6 kcmil ACSS)
Total Cost ($M)	232.5	233.4	234.9
Annual Losses (MWHR)	15,880.30	13,104.01	12,655.21
Losses at System Peak (MW)	2.472	2.040	1.970
Net Present Value ($M)			
Price	**Alt. #1** (1192.5 kcmil ACSR)	**Alt. #2** (1443.7kcmil ACSR)	**Alt. #3** (1433.6 kcmil ACSS)
Energy Price of $53.16/MWHR[1] and Capacity Price of $164,052/MW	-$229.15M	-$224.69M	-$225.13M
Energy Price of $120/MWHR and Capacity Price of $164,052/MW	-$254.54M	-$245.65M	**-$245.37M**

The NPV analysis shows that Alternative #3 is the most economical alternative. All three alternatives meet the capacity needs for the area, but based on the analysis above, Alternative #3 is selected as the preferred and recommended alternative because it is the most cost-effective conductor when also taking transmission line losses into consideration.

[1] Energy price is consistent with the simple average hourly market price forecast that underpins the OEB's October 17, 2025 Regulated Price Plan Price Report

OEB STAFF INTERROGATORY - 08

Reference:

Exhibit B-5-1, Pages 1-2

Preamble:

The Reference refers to the conductor size alternative analysis.

Interrogatory:

a) Please provide the NPV analysis that was conducted for the three alternatives.

Response:

a) Please refer to Attachment 1 for a live NPV analysis in excel format. The conductor selection and engineering design considers the largest useful conductor to ensure an optimal solution for the application as relates to the upstream infrastructure. Please note a confidentiality request has been filled for Attachment 1.

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OEB STAFF INTERROGATORY – 08 ATTACHMENT 1

This attachment has been filed separately in confidence as a MS Excel format.

OEB STAFF INTERROGATORY - 09

Reference:

1. Exhibit B-6-1, Page 1
2. Hydro One's letter dated February 12, 2026 (Submission on Scope of Proceeding and Issues List)

Preamble:

Reference 1 states that the Project is subject to the applicable Class Environmental Assessment (EA) process in accordance with the *Ontario Environmental Assessment Act*. In Reference 2, Hydro One noted that it filed the Final Environmental Study Report (ESR) and Statement of Completion with the Environment, Conservation and Parks (MECP) on November 25, 2025.

Interrogatory:

a) Please provide a copy of the Final ESR.

b) Please discuss how the different route alternatives were developed in the Class EA process. What factors were considered in developing the route alternatives?

c) What are the criteria applied in the evaluation of route alternatives?

Response:

a) The Final Environmental Study Report (Final ESR) is available at the following link: https://www.hydroone.com/abouthydroone/CorporateInformation/majorprojects/Welland-to-Thorold/Documents/Welland_Thorold_ESR_Final.pdf

b) The process used to identify and evaluate alternative routes is detailed in Section 5 of the Final ESR filed with the MECP.

c) Please refer to part b).

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OEB STAFF INTERROGATORY - 10

Reference:

Exhibit B-7-1, Table 1 and Table 2

Preamble:

Hydro One estimated that the total cost of the Project is $311.4 million. Table 1 and Table 2 of Exhibit B-7-1 provided breakdown of the line costs and station costs respectively.

Interrogatory:

a) For both Table 1 and Table 2, please provide a detailed list of the costs included in the contingencies category and the reason for its inclusion.

b) Please describe how the contingency cost estimate for the Project compares to contingency cost estimates developed for projects of similar size and complexity undertaken by Hydro One.

c) Please provide additional details on how the overhead costs were calculated, with additional information on how they relate to the ECI-EPC methodology. Please also provide the calculations of the stated overhead values in Excel format.

d) Please describe how the overhead cost estimate shown in Table 1 and Table 2 for the Project compares to overhead cost estimates developed for similar Hydro One projects.

e) Please also provide breakdown of the overhead cost between direct overheads and indirect overheads. If this cannot be done by Hydro One, please explain why.

f) Please discuss the methodology used to determine the AFUDC as well as the calculations used to arrive at the stated values. Please provide the calculations in Excel format.

g) Please describe how the AFUDC cost estimate shown in Table 1 and Table 2 for the Project compares to AFUDC cost estimates developed for similar Hydro One projects.

Response:

a) For context, Hydro One followed an industry established best practices methodology in developing the contingency utilizing a risk management model. The components of the risk management model are: to obtain inputs from project team stakeholders; to assess level of complexity and subsequent level of structured analysis required; plan a project specific risk model defining project objectives, risk thresholds, roles and responsibilities, and how the remaining risk processes will be implemented; identify all credible threats to the achievement of project objectives and if any opportunities exist that may possibly promote project objectives; analyze the likelihood of occurrence, degree of impact on occurrence, and the prioritization of identified risks slated for further analysis, respond by developing a strategy to treat the risk (i.e. accept, avoid, mitigate, transfer); and execute and control by implementing the planned strategy with continued monitoring and control to confirm effectiveness, make adjustments if needed, and ensure the planned results are achieved.

The risk management model included a qualitative risk analysis that score and rank risks to produce a prioritized list of identified risks and a quantitative risk analysis that numerically analyzes the individual and combined effect of identified risks on project objectives. Using a 3-point estimate, a simulation tool is utilized to run scenario iterations to produce degrees of confidence intervals. For the contingency allocation for the Project, the confidence interval was set at the 85th percentile. Such an analysis provides supporting information which reduces project uncertainty and enables informed decision making. It is important to note that the contingency allocation is not a funded liability for each individual risk cost but rather a probabilistic value based on their likelihood of occurrence.

Given the probabilistic nature of the contingency valuations, a detailed breakdown of the contingency by lines and stations is only available to the extent already presented in Table 1 and 2 above in the Preamble.

b) Please refer to Table 3 below for the comparison of contingency cost estimates relative to overall costs for projects of similar size and complexity recently undertaken by Hydro One. The table below provides more recent projects, however this project has far higher degree of complexity and challenges that should be given consideration in any comparison.

Table 3 - Contingency Cost Comparison

	Waasigan Project-Phase 1	Waasigan Project-Phase 2	Chatham Lakeshore Project	SCTL Project	Welland Thorold
Line Cost	10.5%	9.5%	8.9%	8.4%	14.1%
Station Cost	11.2%	12.3%	4.6%	9.8%	8.0%

In addition to the details provided above that confirm the overall contingency carried in this Project forecast is in-line with similar projects of this size and complexity, Hydro

One notes that the contingency value is a project-specific forecast and will only be utilized if a risk actually materializes on a project that needs to be mitigated.

WTPL is carrying a higher level of contingency due to the unique characteristics of the project. This has more impactful owner-side risks directly tied to schedule compared to other recent projects and reflects more recent geopolitical realities impacting the project.

In addition to the real estate value, it is uncertain what proportion of land rights may be procured voluntarily, or obtained via expropriation. Unlike the other projects referenced, Hydro One determined that it must expropriate properties for WTPL (see four properties in previously filed Section 99 Application) to obtain clear title for permanent land rights. Securing permanent land rights for the new transmission line directly impacts the construction schedule, and therefore the uncertainty has driven associated risk and contingency amounts. Given these project-specific facts, Hydro One's forecast cost provided in Exhibit B, Tab 7, Schedule 1 was predicated upon the relief being granted as sought in this Application, namely, leave to construct and expropriation authorization concurrently. Similarly, the schedule provided in Exhibit B, Tab 11, Schedule 1 was predicated on that relief being secured concurrently. Approvals, permits and authorizations – whether from regulators such as the OEB, or from individual property owners, was highlighted as a major contributor to the contingency for this Project given the risk of delay and cost escalation that can result.[1] Given the relief sought in this Application, relative to the other applications referenced, the forecast risk associated with the risk of concurrent relief denial materializing was considered and is another project-specific example of why this project carried an elevated contingency at time of filing the leave to construct. For further context, sequencing the OEB's expropriation performance standards[2] (180 days) with the OEB's leave to construct performance standards[3] rather than seeking concurrent relief, as now directed by Procedural Order #2, has schedule and cost consequences that needed to be reflected in the cost forecast advanced in the Application.

The WTPL project is very different from a typical greenfield transmission line. There are several distinct stages that require careful coordination between multiple parties, and work groups, as well as outages in some cases. For example, transitioning a customer on a dedicated feed to and from a temporary bypass line in Section B, involving coordination between multiple internal and external parties, is a unique complexity to this project that has a direct impact to the overall project schedule. This

[1] Please refer to p. 3 of Exhibit B, Tab 7, Schedule 1.
[2] https://www.oeb.ca/sites/default/files/Expropriation%20Performance%20Standard.pdf
[3] https://www.oeb.ca/sites/default/files/performance-standard-LTC-Complex-20210401.pdf

complexity, and the associated dependencies introduce additional risks with associated contingency amounts.

When the project was estimated, there was, and continues to be an increased level of uncertainty due to a number of factors outside of Hydro One's control, for example, global and geopolitical uncertainty and the resulting risk impact upon the timing and cost on materials required for the project. Where impact to the project was reasonably foreseen when the project was estimated in Q3 2025, Hydro One has devised a number of plans to avoid or mitigate the impact of these risks and some contingency funds were carried based on the risks identified at that time. However, given the uncertainty, it is unclear if the contingency associated with these risks will be sufficient.

As described above, there are a number of additional uncertainties and pressures that are impacting projects in general, as well as those specific to WTPL given the unique nature of the project. Hydro One followed an industry established best practice methodology in developing the contingency utilizing a risk management model.

c) Hydro One has calculated the overhead cost estimate employing the Early Contractor Involvement model with an external owner's engineer that utilizes the ECI-EPC overhead capitalization rate for both the line and the station. Overhead costs are applied to the direct costs as incurred applicable to the Project utilizing the respective overhead capitalization rate as described above. The calculation equation for each month is Direct Capital Expenditures in month multiplied by the applicable overhead rate. The results of the calculation of the overhead costs are provided in Attachment 1 of this Schedule.

d) The overhead cost estimate shown in Table 1 and Table 2 for the Project is in line with the overhead cost estimates developed for similar Hydro One projects.

e) As detailed in Exhibit B, Tab 7, Schedule 1, the overhead costs in Table 1 and Table 2 relate to only indirect overheads.

f) As disclosed in Hydro One's Joint Rate Application (EB-2021-0110), consistent with the OEB's Decision in EB-2008-0408 effective January 1, 2012, no AFUDC rate is specified for use by Hydro One. Hydro One was directed to base its interest capitalization rate on its embedded cost of debt used to finance capital expenditures. This is also consistent with Hydro One's adoption of United States Generally Accepted Accounting Principles (US GAAP) per the OEB's Decision in EB-2011-0268 for Transmission and US GAAP requirements for determination of interest capitalized. Results of the calculations for the AFUDC costs outlined in Table 1 and Table 2 of Exhibit B, Tab 7, Schedule 1, are provided as Attachment 1 to this Schedule.

As described in b), there exists uncertainty associated with the timelines for expropriation. As further described in b), Hydro One has carried contingency associated with the delay due to expropriation proceedings as a risk with a high probability of occurring. A risk based approach has been utilized with funds carried in the project contingency in lieu of AFUDC carried in 2029.

g) There is no difference in the AFUDC methodology utilized in this Project relative to any other Hydro One project. The AFUDC methodology is consistently applied whether the project is delivered using an ECI-EPC or standard Hydro One delivery model. Any differences in total interest capitalized is a function of the interest rates at the time of construction versus prior periods and the expenditures on the Project

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OEB STAFF INTERROGATORY – 10 ATTACHMENT 1

This attachment has been filed separately in MS Excel format.

OEB STAFF INTERROGATORY - 11

Reference:
Exhibit B-7-1, Pages 2-3

Preamble:
In the Reference, Hydro One stated that the Project cost estimate is based on a fixed price EPC contract, and the selection of the EPC contractor used a two-stage process that is variant but ultimately akin to the OEB-approved ECI-EPC project delivery model.

Interrogatory:

a) Please clearly describe the two stages of the process noted in the Preamble. (Please clearly list the steps taken in each stage.)

b) Please indicate which part(s) of and how the process is variant to the OEB-approved ECI-EPC project delivery model.

c) Please discuss how the EPC contractor was selected among different EPC contractors. Please include a list of the specific functions the contractors were assessed on.

d) Please discuss how Hydro One determined that utilizing the successful contractor's bid is more cost-effective than Hydro One performing the work itself.

e) In the EPC selection process, how many contractors were qualified under Stage 1? Please list all contractors that were considered qualified.

f) How many contractors submitted bids in Stage 2 of the process? Please provide the cost quotes in the proposals received by each bidder in Stages 2 and explain how the final proposal was selected.

g) Please clarify how the Project cost was estimated based on the fixed price EPC contract, and why the cost estimate reflects market price.

h) Please provide a list of early activities the contractor will be conducting that require a long lead procurement process.

i) Please provide details on how cost overruns will be handled between Hydro One and the selected contractor.

j) Please provide a breakdown of the fixed price EPC contract by line costs and station costs.

k) What is the magnitude of the EPC contract as a percentage of the total Project cost?

Response:

a) Stage 1 – ECI/Development
Stage 2 – EPC Selection and Execution

As per previous Hydro One responses in EB-2023-0198 Exhibit I, Tab 1, Schedule 19 a), The ECI-EPC model adopted by Hydro One for this Project is designed to involve the contractor into the development and design phases earlier than Hydro One's standard EPC model. Doing so is intended to provide a more efficient and effective approach as the Project proceeds through these stages and into the Project's construction phase. Continuity within these stages is particularly important for larger scale and complex projects such as the WTPL Project.

The initial stage of the ECI-EPC process is for Hydro One to leverage the external owner's engineer to assist Hydro One with the qualification of potential EPC bidders based on experience and capacity to perform many of the development functions that under the standard Hydro One EPC delivery model which would be performed internally by Hydro One. At this stage, a variant to previous ECI-EPC was required to select a single potential vendor due to unique land corridor constraints to limited engineering solutions, as described in Exhibit I, Tab 1, Schedule 11 b) below.

The second stage of the ECI-EPC model was utilized by having the contractor on board early in the development phase for greater involvement in the Project scoping, engagement with rightsholders and stakeholders, and evaluating risks and opportunities (including preparing potential solutions and mitigation measures). This contractor involvement allowed for better human resource allocation and allows Hydro One to utilize its internal resources in more efficient and effective ways. The contractor involvement also provides Hydro One with the opportunity to evaluate the EPC contractor's contributions and work relationship to this particular project prior to entering into the more substantive construction contract.

In the final stage, Hydro One was able to utilize the initial stage to tailor contract terms appropriately and at a time that is advantageous to the project schedule, cost and scope.

This modified ECI-EPC is similar to well established collaborative contracting methodologies used in public procurement in many jurisdictions and industries.

b) Due to constraints on the land corridor and regional system needs, it was determined in consultation with the Owners Engineer at the first stage of the ECI-EPC model that a single contractor, that was successfully executing the St. Clair Transmission Line (SCTL) Project, would be appropriate for this project. This allowed Hydro One to leverage similar project elements of pre-existing work in the region to be very responsive to local and regional system needs based on IESO needs, and to accommodate the stakeholder feedback in the region.

Costs were developed from an agreed-to open book process with full transparency on the procurement process, as well as the bottom-up estimation process, including production rates and crew composition. There was extensive focus to validate the contractor's estimate against market benchmarks, and analysis supported from the Owner's Engineer. From a cost perspective, the contractor agreed to open book negotiations for the contract pricing and commercial terms. Competitive tension has been maintained via competitive procurement at the sub-tier level (subcontractor and material procurement). Key components and outcomes of the ECI-EPC process have been maintained throughout.

This modified ECI-EPC is similar to well established collaborative contracting methodologies used in public procurement in many jurisdictions and industries.

c) Initially, a number of potential EPC contractors were considered that have proven to be successful ECI-EPC vendors to Hydro One in the past.

The WTPL project would require a solution to construct a new double circuit 230kV transmission line within a confined nominal-30m right of way. In addition, for Section B, it is required to confine a triple circuit transmission line, as well as a temporary 115kV bypass line within the same confined right of way.

Feedback from the IESO[1], as well as stakeholders and rights holders[2] were aligned with re-using the A3C/D3A corridor for the new transmission line.

At the time, Hydro One was working with a contractor, on another project in the area, who had successfully designed a technical solution to confine a double circuit 230kv line into a 30m right of way and had demonstrated finding innovative technical solutions to similar problems. A standard solution would require significant widening of the existing corridor which would greatly increase the land acquisition costs, timelines, and may not be feasible. Due to regional requirements and constraints, the

[1] See Exhibit H-1-1, IESO IRRP – Section 7.4.1
[2] See WTPL Environmental Assessment, Table 3-5, second comment.

IESO explicitly recommended the re-use of sections of the A3C/D3A corridor that resulted in a triple circuit arrangement (Section B) which necessitated an evolution of the solution to confine the double circuit 230kv line into the existing 30m right of way.

Similar 30m right-of-way solutions were provided in the SCTL project, and as such, this provides Hydro One confidence in the contractor to deliver similar technical solutions to meet the constraints of this project.

Finally, the entire process considers time constraints to meet the in-service date required by the system. Therefore, to leverage the existing solution and expertise, Hydro One selected the contractor that developed the solution to confine a double circuit 230kV transmission line within a 30m right of way on SCTL.

To achieve potential savings that could be harvested in a multi-ECI approach, the EPC contractor agreed to an open book bidding process with Hydro One.

d) Hydro One leverages a procurement model that enables contractors (EPC or other) to be engaged early in the project lifecycle to enable integration of design development and construction planning, with other regulatory activities, resulting in a bespoke and refined solution for the execution phase. The contractors are compensated, at cost, for their participation in the development phase.

As described in c), the EPC contractor has existing major work within the area of the province. It was determined that existing ongoing work, and the technical solution developed on that project could be leveraged to deliver efficiencies on WTPL. As mentioned in Exhibit I, Tab 1, Schedule 11 c), due to similar project elements, Hydro One's contractor demonstrated the tailored-made solutions to meet project constraints similar to that in the SCTL project, and as such, provides a more cost-effective solution to meet the needs of the WTPL project. Hydro One leveraged our knowledge and experience developed on SCTL to efficiently find a technical solution to address the constraints on WTPL.

Costs were developed from an agreed-to open book process with full transparency on procurement process, as well as the bottom-up estimation process, including production rates and crew composition. There was extensive focus to validate the contractor's estimate against market benchmarks, and analysis supported from the Owner's Engineer. From a cost perspective, the contractor agreed to open book negotiations for the contract pricing and commercial terms. Competitive tension has been maintained via competitive procurement at the sub-tier level (subcontractor and material procurement). Key components and outcomes of the ECI-EPC process have been maintained throughout.

The modified ECI-EPC model with open book process described above was utilized. This allowed a solution to re-use the A3C corridor incorporating an alternative design that confined a double circuit 230kv line into a 30m right of way in Section C, as well as re-use of the A3C/D3A corridor to confine a triple circuit and 115kV bypass line within the same 30m right of way in Section B. Furthermore, utilizing the modified ECI-EPC process allowed Hydro One and the EPC to appropriately identify and allocate risks between the parties and utilize effective and appropriate solutions to meet the needs of the system.

e) Hydro One reviewed our list of transmission line Qualified Service Providers that are used for the ECI-EPC delivery model. From Hydro One's past experience of working extensively with these contractors and the recent experiences on the SCTL project, Hydro One selected this specific EPC contractor as they had demonstrated the skills required to meet the unique constraints on this project.

f) [redacted]

[redacted]

g) [redacted]

[redacted]

h) Below is a listing of early activities the contractor will be conducting that require a long lead procurement process:

- Field activities requiring access to the transmission line right of way, requiring access to the full transmission line right of way:
    - Accessing the transmission line right of way to conduct field studies to support timely construction permit applications
    - Geotechnical investigation at tower locations to support final foundation design
- Procurement of transmission line conductor
- Procurement of structural steel for transmission line towers
- Procurement of steel for transmission line tower and station foundations
- Procurement of transmission line tower hardware
- Procurement of long lead major equipment (e.g., disconnect switches, PCT Building)

i) [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
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OEB STAFF INTERROGATORY - 12

Reference:
Exhibit B-7-1, Pages 4-9

Preamble:
In the Reference, Hydro One compared the line cost of the Project with the following three projects:

- Guelph Area Transmission Refurbishment Project
- Power South Nepean Projec
- Woodstock Area Transmission Reinforcement

However, two of Hydro One's most recent and geographically relevant projects — the Chatham–Lakeshore Transmission Line (EB-2022-0140) and the St. Clair Transmission Line Project (EB-2024-0155) — are not included in the comparable project analysis.

Interrogatory:
a) Please explain why the Chatham–Lakeshore Line and the St. Clair Project were not included as comparators for the Welland–Thorold Project.

b) Please provide a sensitivity analysis showing how the Welland–Thorold unit costs ($/km) compare to the actual costs of the Chatham–Lakeshore Line and St. Clair Project.

Response:
a) Pursuant to the OEB Chapter 4 Filing Requirements, a comparator project must be a recently completed project. As of the date of this interrogatory response, the St. Clair Project (SCTL) is not in-service and is therefore not viable for comparison. The Chatham – Lakeshore Transmission Line is in-service but was not considered a reasonable comparison because the project scopes vary significantly.

As described in Exhibit B, Tab 7, Schedule 1, the comparator projects were selected as reasonable comparable projects because they are all 230kV double-circuit transmission lines of similar length and all project scopes included works on 115 kV infrastructure to complete the project.

Conversely, Chatham to Lakeshore (CxL) scope is a much longer transmission line and was limited to 230 kV line work and was therefore not considered a reasonable comparison. Furthermore, the constraint of requiring a 30m right of way that necessitated incorporating alternative design that allowed a double circuit 230kv line was not a factor in the Chatham to Lakeshore project as the project largely was delivered utilizing typical solutions.

While the solution to confine a double circuit 230kV transmission line to a 30 m right of way, instead of the typical 46 m right of way, was developed on the SCTL project, the majority of the line is more similar to CxL utilizing typical solutions.

Finally, it should be noted that all projects listed above, including CxL, were planned and materials ordered prior to the global adjustments in trade and the impact on energy projects that the industry is experiencing that is not fully captured in broad CPI metrics.

b) Please refer to part a) why the priority transmission line project, Chatham to Lakeshore, is not a comparable project to the Welland Thorold Project. Notwithstanding that, Hydro One has provided the requested information as requested and attempted to compare the unit costs accordingly with modifications made where necessary to reflect a more comparable unit cost**.**

In comparison to Chatham to Lakeshore, an additional adjustment has been made to the WTPL project to account for the reduced space off right of way and the impact to access construction due to WTPL's highly developed surroundings. The Chatham to Lakeshore project was constructed in agricultural surroundings that allowed for a much greater degree of flexibility in working space, material laydown, and construction access planning outside the right of way. This reduced working space results in less efficient, more costly modified work practices. In addition to the reduced off right of way working space, the WTPL project is located in an area with much more developed roads, and road crossings are closer together in these developed areas, which results in more costly, and more numerous off corridor road entrances. The adjustment is calculated based on the additional incremental cost for associated with the reduced access and more costly construction access in WTPL compared to more rural surroundings.

For the St Clair project, as per a) above, it is not a viable comparator as the project is not complete with work continuing in 2026 and 2027.

Project	Chatham x Lakeshore Transmission Line	Welland Thorold Power Line (Line Cost)
Circuit Operating Designation(s)	C87H and C88H	Q24HM and Q29HM
Voltage	230 kV	230 kV
Structure Type	Steel Lattice	Steel Lattice
Single or Double Circuit	Double	Double, Triple
Conductor	1443.7 kcmil ACSR/TW	1433.6 kcmil ACSS/TW
Location	Southwest Ontario	Southwest Ontario
Project Surroundings	Mostly Rural	Urban, rural, commercial, multiple crossings
In-Service Year	2024	2029
Estimate or Actual	Actual	Estimate
OEB-Approved Cost Estimate	$235,272K	–
Total Cost	$208,280K	$234,900K
Less Adjustments:		
Real Estate	$78,200K	$40,300K
Micropile Foundation	*N/A*	*N/A*
Bypass	*N/A*	*$9,990K*
Triple Circuit	*N/A*	*$17,610K*
Adjacent Energized Line	*N/A*	*$7,350K*
Nonlinear Corridor	*N/A*	*$11,350K*
Taller/Larger/Heavier Structures	*N/A*	*$16,400K*
Constrained/Narrower RoW	*N/A*	*$42,040K*
Reduced Space Off-RoW Space and Developed Surroundings	*N/A*	*$16,190K*
Comparable Costs, before Escalation	$130,080K	$73,670K
Escalation Adjustment[1]	$22,971K	N/A
Total Adjusted Comparable Cost	$153,071K	$73,670K
Approximate Length	49.0 km	18.5 km
Unit Cost	**$3,124K/km**	**$3,982K/km**

[1] Interest Rate based on the OEB-approved inflation rate utilized to set rates for electricity transmitters. Note: the 2020 inflation rate of 2% assumed for years prior to 2022.

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OEB STAFF INTERROGATORY - 13

Reference:

Exhibit B-7-1, Pages 4-12, Table 5 and Table 6

Preamble:

In the Reference, Hydro One provided analysis of costs on comparable projects for both line work and station work of this Project.

Interrogatory:

a) In Table 6 of Exhibit B-7-1, there is an adjustment item of "Feeder Reconfiguration".
   i. Please discuss what this cost is and how the value ($4,500k) was decided for Crowland TS.
   ii. Please also confirm that the Feeder Reconfiguration cost is not applicable to the three comparable projects.

b) In Table 6, there is an adjustment item of "Brownfield Site Clearing".
   i. Please discuss what this cost is and how the value ($3,300k) was decided for Crowland TS.
   ii. Please also confirm that the Brownfield Site Clearing cost is not applicable to the three comparable projects.

c) In Table 6, there is an adjustment item of "Ground Conditions".
   i. Please discuss what this cost is and how the stated values for three stations (Minden TS, Arnprior TS and Crowland TS) were decided.

d) For both Table 5 and Table 6, Hydro One noted that the inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.
   i. Please confirm if Hydro One has applied the OEB's 2026 inflation parameters in the escalation adjustment.
   ii. If not, please update the escalation adjustment calculations for both Table 5 and Table 6 using the OEB's 2026 inflation parameters.
   iii. For both Table 5 and Table 6, Please indicate what inflation parameter has been used for the years 2027, 2028 and 2029.

e) For both Table 5 and Table 6, please provide detailed calculations (in Excel format) for the Escalation Adjustmsent values (or the Total Adjusted Comparable Cost) for the three comparable projects. The calculations should show the annual inflation parameters applied for each year.

f) Based on the total adjusted comparable costs shown in the last row of Table 6, the average cost of the three comparable stations is about $47,551k (in 2029 dollars). The estimated adjusted cost of Crowland TS of $51,930k is about 9.2% higher than the average cost of the three comparable projects. Please discuss why Crowland TS has a relatively higher estimated adjusted cost compared to the average cost of the three comparable projects.

Response:

a)

i. Due to the new Crowland TS station being constructed in close proximity to the existing operational station equipment, the existing feeder egress obstructs the routing for the new feeder egress. Due to the highly developed surroundings, quantity of feeders, and existing live station infrastructure, the area available for feeder egress is highly confined. For example, there is a railway directly bordering the west of the station, a private industrial complex directly North, residential directly east of the station property, and a steep embankment for the MTO tunnel across the road to the south of the station. The new feeder egress construction is subject to complex staging to enable safe construction around existing live equipment, and as well to minimize outages as feeders are migrated to the new station area.

The feeder reconfiguration cost is the estimated cost required for the complex staging to enable safe construction around existing live equipment and minimize outages to reconfigure the feeders currently being supplied by the existing 115kV/28kV equipment at Crowland TS to egress from the new 230kV/28kV DESN to be constructed as a part of this project.

ii. While St. Isidore TS, Minden TS, and Arnprior TS projects were replacements of existing stations, they were all constructed in greenfield station areas on undeveloped land, with much more space for a fewer quantity of feeders, and were therefore not impacted by the complex staging and confined area to reconfigure and migrate numerous feeders to the new station that exists at Crowland TS.

b)

i. The adjustment for brownfield site clearing is the estimated cost impact related to clearing, preparing, and working within a brownfield station area to construct the new 230kV/28kV DESN station. Crowland TS is located on land that was historically used for industrial purposes. There has been extensive preparatory work to investigate and validate subsurface conditions, identify existing buried infrastructure and there remains extensive preparatory work to reroute infrastructure that must remain functional, or remove defunct infrastructure leftover from historical uses of the property.

Further, the majority of the new 230kV/27.6kV station will be constructed within the existing fenceline of the existing, operational 115kV/27.6kV station, further complicating all site preparation and construction activities as work practices are modified or restricted to maintain worker safety around live equipment and minimize, or avoid outages to existing equipment.

ii. While St. Isidore TS, Minden TS, and Arnprior TS projects were replacements of existing stations, they were all constructed in greenfield station areas on undeveloped land, and were therefore not impacted by the brownfield post-industrial site conditions at Crowland TS.

c)

i. Ground conditions can vary greatly between different geographic sites based on geotechnical conditions, as well as other ground conditions like the water table, drainage, and other factors. Subsoil or ground conditions may have some impact on at-grade or above ground structures, but these conditions are much more impactful to below-grade foundations. The adjustment for ground conditions considers the below ground, deep foundations (e.g., piles) required, that are particular to specific ground conditions at each site.

d) For Table 5 and Table 6 at Exhibit B, Tab 7, Schedule 1, Hydro One escalated costs based on the OEB inflation parameters in place as at the year of escalation for all costs from 2022 onwards.[1] For escalations necessary from 2026 onwards, Hydro One applied and held constant the OEB's current 2026 inflation parameters through to the in-service date in 2029.

e) Please refer to Attachment 1.

f) The proposed new Crowland TS is comparable to the cited stations in Exhibit B, Tab 7, Schedule 1, Table 6 as all stations contain 2 transformers. The new Crowland TS will have a substantially higher maximum transformation capacity than any of the comparable station projects that will result in slightly higher costs. The new Crowland TS will have a maximum rating of 125 MVA whereas the comparatives have lower total station ratings of 83 MVA (St. Isidore TS and Minden TS) and 42 MVA (Arnprior TS). The higher transformation capacity is associated not only with the size and cost of the

[1] For all years prior to 2022, a 2% inflationary increase was assumed.

transformers, but much of the associated station infrastructure to support. For example: foundations, bus sizes, bus supports, major equipment (e.g., disconnect switches, circuit breakers), as well as supporting equipment such as oil containment and oil-water separator size.

OEB STAFF INTERROGATORY – 13 ATTACHMENT 1

This attachment has been filed separately in MS Excel format.

OEB STAFF INTERROGATORY - 14

Reference:

1. Exhibit B-1-1, Pages 2
2. Exhibit B-9-1, Pages 1-2

Preamble:

As stated in the application, the construction of a new sectionalizing station, Crowland SS, will be a separate project to allow proper protection and load capacity in accordance with recent requirements defined in the IESO's Final SIA. Reference 1 states that Crowland SS is considered as a functionally distinct project and is needed only after completion of the Welland Thorold Project.

As per the application, the estimated cost of $55.6 million for Crowland SS is not included in the total cost of the Welland Thorold Project.

Reference 2 states that the costs that underpin the economic feasibility and rate impact assessment include the new switching station (Crowland SS) that is required to achieve the full incremental load per the Final SIA. Reference 2 also states that the Project will enable 180 MW of supply capacity

Interrogatory:

a) What is the amount of the full incremental load per the Final SIA? Is it the 180 MW of supply capacity that the proposed (Welland Thorold) Project will enable as stated in Reference 2?

b) If the construction of Crowland SS is required to achieve the full incremental load of the area, please provide the rationale for the exclusion of Crowland SS in the proposed Project.

c) If Crowland SS should be considered as a separate project and its cost is not included in the proposed Project's total cost, please provide the rationale for the inclusion of the cost of Crowland SS in the network pool rate impact assessment.

Response:

a) The Final SIA studied a total incremental load of 121.1 MW associated with the Project. The proposed (Welland Thorold) Project is physically capable of providing over 400MW of power but due to system factors is limited to only providing approximately 180MW. The restriction to 180MW is due to an IESO restriction on the impact to the power transfer interface. Please refer to Exhibit I, Tab 1, Schedule 6, for more information on the 180MW.

b) The addition of the Crowland SS will address broader system needs that IESO has noted in their SIA. As detailed in Exhibit B, Tab 1, Schedule 1, as a separate project, a new sectionalizing station, Crowland SS, will be constructed to allow proper protection and load capacity in accordance with recent requirements defined in the Independent Electricity System Operator ("IESO") Final System Impact Assessment ("SIA"). As further described at page 7 of the SIA: "To allow proper protection of Q29HM and Q24HM circuits **after the project** (emphasis added), Hydro One Networks Inc. will sectionalize the Q29HM and Q24HM circuits by adding an inline breaker on each circuit about 14 km away from Beck 2 TS, west of the connection point for the project." As load materializes and exceeds an established threshold of more than 113 MVA load addition to Q24HM or Q29HM will require sectionalizing the circuit. the sectionalizing station is required. For this purpose, the SS is not required for the Project. However, to reach the full 180 MW of benefit that flows to the broader network, and that underpins the economic evaluation provided in Exhibit B, Tab 9, Schedule 1, the sectionalizing station would be required and is therefore included in the economic evaluation provided.

c) Please refer to part b).

OEB STAFF INTERROGATORY - 15

Reference:
Exhibit B-9-1, Pages 2-3

Preamble:
As stated in the application, the construction of a new sectionalizing station, Crowland SS, will be a separate project to allow proper protection and load capacity in accordance with recent requirements defined in the IESO's Final SIA. Reference 1 states that Crowland SS is considered as a functionally distinct project and is needed only after completion of the Welland Thorold Project.

As per the application, the estimated cost of $55.6 million for Crowland SS is not included in the total cost of the Welland Thorold Project.

Reference 2 states that the costs that underpin the economic feasibility and rate impact assessment include the new switching station (Crowland SS) that is required to achieve the full incremental load per the Final SIA. Reference 2 also states that the Project will enable 180 MW of supply capacity

Interrogatory:

a) Please clarify the functional categories of the following circuits: Q24HM, Q29HM, D3A, A3C, A6C, A7C, A1C, and A1T. Will any of these functional categories change as a result of this Project?

b) If any of these circuits are dual function lines, please provide their allocation factors between the network and connection pools.

c) Please identify all the customers supplied by Crowland TS and the proportion of the station capacity and of the A6C/A7C circuits that is allocated to each of them.

d) Please provide the assigned capacity of each customer for the two new 230 kV circuits.

Response:

a) There are no functional categorization changes as a result of this Project. The existing functional categorization for any of the active circuits referenced detailed below

Q24HM	Dual-Function Line
Q29HM	Dual-Function Line
D3A	Line Connection
A3C	OTHER (IDLE)
A6C	Line Connection
A7C	Line Connection
A1T	OTHER (IDLE)

b) Q24HM and Q29HM are dual function lines and their allocated split, consistent with the allocation factor for dual function lines presented in Hydro One's most recent revenue requirement application[1], is detailed below.

Designation	% Network	% Connection
Q24HM	84%	16%
Q29HM	84%	16%

c) Consistent with Appendix B of the OEB's Practice Direction on Confidential Filings[2], information that would disclose load profiles, energy usage and billing information of a specific customer that is not personal information is presumptively considered confidential. For the purposes of transparency with respect to the interrogatory posed, Hydro One can provide that the total load for the customers connected at Crowland TS listed in the table below. Welland Hydro and Hydro One Distribution are the two local distribution companies supplied by Crowland TS.

The proportion of station capacity based on assigned capacity at Crowland TS during the most recent 60 month period is

Customer	Assigned Capacity at Crowland TS	Proportion of Station Capacity based on Assigned Capacity (Crowland TS LTR = 101.7MW)
Hydro One Distribution	12.8 MW	12.6%
Welland Hydro	85.0 MW	83.6%

d) As Crowland TS is the only station currently supplied by the proposed Project, the assigned capacity for the two new 230kV circuits will be the same as c).

[1] hydroone.com/abouthydroone/RegulatoryInformation/JointRateApplications/Documents/HONI_Appl_Exhibit H_20210805.pdf

[2] Practice Direction on Confidential Filings, Issued December 17, 2021

OEB STAFF INTERROGATORY - 16

Reference:
Exhibit B-9-1, Page 2

Preamble:
The Reference states that:
As identified by the IESO, the purpose of the Project is to:

- resolve the Crowland TS capacity and replacement needs,
- resolve the A6C/A7C security issue, and
- enable other load growth on the 115 kV sub-system.

The alternatives to assess how to address these system needs were studied in the Niagara Integrated Regional Resource Plan and subsequent Regional Infrastructure Plan and the Project addressed all needs for almost one-third of the cumulative cost of all other solutions. [Footnote omitted]

Interrogatory:

a) Please describe the other solutions and provide the cost for each of those solutions.

b) Please provide the cumulative cost for each of all other solutions and demonstrate that the cost of the Project is almost one-third of the cumulative cost of all other solutions.

Response:

a) Please refer to Exhibit B, Tab 3, Schedule 1

b) Please refer to Exhibit I, Tab 1, Schedule 18 part b).

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OEB STAFF INTERROGATORY - 17

Reference:
Exhibit B-9-1, Page 2

Preamble:
The Reference mention enabling load growth and resolving the A6C/A7C security issue, as well as a long-term transition towards eliminating the 115 kV supply in the area.

Interrogatory:

a) Please explain whether the project resolves the A6C/A7C security issue or merely reduces its severity.

b) Please comment on how load growth and new connections in the area are envisioned to be divided between the 115 kV and 230 kV networks in the future.

c) Please explain where the 180 MW of additional load could be connected. That is, could it all be connected at Crowland TS, on the two new 230 kV circuits, or a broader range of connection points? Please explain any constraints on load connections to access this capacity or any circumstances in which the project will enable less than 180 MW of capacity, i.e. due to inefficient connection points.

Response:

a) As detailed in 7.5 of the Regional Infrastructure Plan provided at Exhibit H, Tab 1, Schedule 1, Attachment 1 and in concert with the other needs the Project addresses as detailed in Exhibit B, Tab 3, Schedule 1, the Project reduces the severity of the load security issue by the amount of load forecast at Crowland TS.

   The Project removes the existing Crowland TS loads from the 115kV A6C/A7C circuits, however, under the Allanburg Load Rejection scheme, over 150MW of load may still be interrupted, above the 150MW load security threshold as defined in the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC)1.

   The A6C/A7C security issue reference in this interrogatory should therefore read as "reduce" rather than "resolve", consistent with the aforementioned references in the Application.

[1] https://www.ieso.ca/-/media/Files/IESO/Document-Library/Renewed-Market-Rules-and-Manuals/market-manuals/connecting/ieso-con-ontario-resource-transmission-assessment-criteria.pdf

b) All new customers in the area requiring a transmission connection will be connected to the new 230kV network. All existing connected customers with forecast growth will continue to be connected to the 115kV network unless the additional need is beyond the customer's station capacity and required to be connected to the new 230kV facilities. Please refer to Exhibit B, Tab 3, Schedule 1, Attachment 1, Section 5 for further information from the IESO with respect to future planning in the Niagara area.

c) The 180MW of load could be connected within the station capacity of Crowland TS, and/or at any point along the new 230kV corridor. Notwithstanding the disclosed necessary implementation of Crowland SS beyond a threshold of 113MVA[2], there are no electrical constraints on load connections to access this 180MW capacity.

[2] As discussed at Exhibit I, Tab 1, Schedule 6.

OEB STAFF INTERROGATORY - 18

Reference:
Exhibit B-9-1, Pages 2-3

Preamble:
The Reference mention enabling load growth and resolving the A6C/A7C security issue, as well as a long-term transition towards eliminating the 115 kV supply in the area.

Interrogatory:

a) Please explain whether Hydro One is proposing to classify the new 230 kV line as a network facility. Is there a change in classification from the existing 115 kV lines that supply Crowland TS?

b) Please explain the basis for allocating the cost of increased station capacity work at Crowland TS to the connected customer, while allocating the cost of the new 230 kV supply line to that Crowland TS to the network pool.

c) Please explain whether any portion of the 230 kV line investment is directly attributable to the Crowland TS expansion and should therefore be treated as line or transformation connection.

d) Please provide precedents from other projects where a connection facility was cost allocated in its entirety to the network pool.

Response:

a) Hydro One is not proposing to classify the new 230 kV line as a network facility. The line is properly classified as a connection facility. However, pursuant to section 6.3.18 of the Transmission System Code (TSC), classification and cost allocation are distinct analytical steps. Section 6.3.18 expressly contemplates that a connection facility may (i) be triggered by a customer, or; (ii) address a broader network system need, as confirmed through an IESO system impact assessment.

   In such circumstances, costs are to be attributed between the triggering customer(s) and the network pool based on relative benefit. For the WTPL scenario, the 230 kV line is triggered by load growth at Crowland TS, it is also required to:

   - Address A6C/A7C security constraints and ORTAC compliance
   - Enable the transition away from long-term reliance on 115 kV supply
   - Provide regional capacity and reliability benefits

Accordingly, there is no inconsistency in either classifying the facility as a connection asset, and attributing its costs to the network pool based on system benefits. There is also no substantive change in classification from the existing 115 kV facilities. The Project reflects a system evolution in supply configuration, not a reclassification of asset function.

b) The allocation reflects a direct application of the TSC framework, and in particular the sequencing inherent in section 6.3.18:
   1. Identify whether the facilities address customer-specific needs and/or broader system needs; and
   2. Attribute costs based on relative benefit

   The distinction between these two components of the Project is clear. Capacity work related at Crowland TS represents a discrete, customer-driven increment in capacity, directly attributable to the connecting customer's request for additional load service. This work does not, in isolation, resolve broader system constraints. Accordingly, these costs are properly allocated to the customer under the connection cost responsibility framework.

   In contrast, the applied-for 230 kV transmission line facilities comprises an integrated solution identified through regional planning[1] to address multiple system needs, including:
   - 115 kV supply limitations
   - A6C/A7C security issues and ORTAC compliance
   - Provides system-wide reliability and capacity benefits beyond the needs of the connecting customer
   - Represents the least-cost alternative, avoiding approximately $354M in other system investments, compared to an estimated Project cost of approximately $128M

   In these circumstances, the dominant benefits of the line are system-wide, and attribution to the network pool is appropriate and consistent with section 6.3.18.

c) Hydro One submits that no portion of the 230 kV line investment should be directly attributed to the Crowland TS expansion.

   This conclusion is supported by the following:
   1. Functional indivisibility:

[1] IESO Regional Resource Plan – December 22, 2022

The 230 kV line is a single, integrated facility designed to address multiple system needs. It is not possible to isolate a discrete portion that serves only the connecting customer.

2. System need independent of the trigger:
   The Regional Infrastructure Plan identifies 115 kV system limitations and A6C/A7C security constraints that require resolution irrespective of the specific customer connection. The customer's load triggers timing, but not the scope or configuration of the investment.

3. Least-cost system solution:
   The Project represents the lowest-cost means of addressing a bundle of system needs. Allocating a portion of the line to the customer would not reflect the distribution of benefits and would be inconsistent with the TSC's cost attribution framework.

   Accordingly, the 230 kV line is appropriately treated as a connection facility with costs fully attributed to the network pool based on system benefit.

d) The OEB has recognized, both in policy and in prior decisions, that connection-classified facilities may be fully allocated to the network pool where they provide system-wide benefits. Precedents include:

   1. Section 6.3.18 of the TSC: Codifies the principle that connection facilities may be partially or fully attributed to the network pool, depending on the distribution of benefits, subject to OEB approval.
   2. EB-2020-0265 (Hawthorne x Merivale): While not always framed explicitly under section 6.3.18, this decision applied the principle that facilities performing a system reliability or capability function are appropriately treated as network-costed, even where triggered by specific customers or localized needs.
   3. EB-2023-0360 (PUC / Algoma Steel): The Board most recently affirmed that load-triggered transmission investment may be treated as network infrastructure where supported by IESO planning and broader system need.

Taken together, these authorities support the proposition that where a connection facility delivers predominant system benefits, full attribution to the network pool is appropriate.

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OEB STAFF INTERROGATORY - 19

Reference:
Exhibit B-9-1, Pages 2-3

Preamble:
The application states that the Project is not associated with a specific load increase or customer load application. Additionally, the application states that the two new 230 kV circuits to Crowland TS functionally serves as a line connection facility but costs are proposed to be allocated to the network pool.

Interrogatory:

a) Please confirm whether Hydro One considers this investment in the two new 230 kV circuits to Crowland TS to be customer-triggered for the purposes of Transmission System Code (TSC) section 6.3.18. If not, please explain why not.

b) Please confirm whether, in Hydro One's view, Crowland TS customers will benefit from the two new 230 kV circuits and explain why.

c) Please comment on any plans for how customers would reimburse the network pool in the future as load growth occurs and/or new customers connect to the two new 230 kV circuits.

Response:

a) No, the two new 230kV circuits are not triggered by any specific customer. The need for the Project is established through the Integrated Regional Resource Plan and Regional Infrastructure Plan provided in Attachments 1 and 2 of Exhibit H, Tab 1, Schedule 1, respectively. That need is outlined in Exhibit B, Tab 3, Schedule 1 and therein it is articulated that the Project is to address:

    i. Niagara Region 115 kV supply capacity concerns[1]: the loads on the Niagara Region 115kV system exceeds the 115 kV system supply capability under certain contingency conditions which result in three out of the four autotransformers being out of service at Allanburg TS;
    ii. Overloading concerns on circuits A6C and A7C within the 115 kV network by transferring the Crowland TS load to a 230 kV supply[2];
    iii. Crowland TS capacity and asset renewal needs[3]; as well as

[1] IESO Regional Infrastructure Plan – July 12, 2023 – Section 7.2.1
[2] Ibid. Section 7.1.2
[3] Ibid. Section 7.3.2 and 7.4

iv. Load security concerns on circuits A6C and A7C as the load forecast on these` circuits exceeds the permissible limit set by ORTAC.[4]

b) Yes, please refer to Exhibit B, Tab 3, Schedule 1, Attachment 1 and Exhibit H, Tab 1, Schedule 1, Attachments 1 and 2. The Project enables broad system benefits that benefit all customers in the area including those fed from Crowland TS as outlined in part a) above.

c) Please refer to Exhibit I, Tab 1, Schedule 18. It is not expected that costs for the Project will exceed the levels necessary to initiate any contemplated refund. Furthermore, the network pool will be reimbursed through increased rate revenue due to load growth and from new customers that connect to the available capacity created by the Project. Please refer to Exhibit B, Tab 9, Schedule 1.

[4] Ibid. Section 7.5

OEB STAFF INTERROGATORY - 20

Reference:
1. Exhibit B-9-1, Page 3
2. Exhibit C-1-1, Page 5
3. Exhibit H-1-1, Attachment 1, Page 43

Preamble:
Reference 3 recommends installing two new 75/125 MVA transformers at Crowland TS. Reference 1 and Reference 2 provide conflicting sizes for these transformers (100 MVA vs. 125 MVA).

Interrogatory:
a) Please clarify the size of the transformers to be installed at Crowland TS.

Response:
a) Hydro One will be installing two new 75/125 MVA transformers at Crowland TS.

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OEB STAFF INTERROGATORY - 21

Reference:
Exhibit B-9-1, Pages 5-14, Tables 1-9

Preamble:
In the Reference, Hydro One provided rate impact assessment for both network pool and transformation connection pool.

Interrogatory:

a) The OEB issued the most recent 2026 Uniform Transmission Rates (UTRs) Decision and Rate Order (EB-2025-0232) on January 15, 2026. Please provide the calculations and results of the discounted cash flow analysis and rate impact assessment based on the updated Network Service Rate. (Please include all the updated tables for Tables 1-9)

b) In Table 9 “DCF Assumption”, Hydro One included the following note:

> Based on OEB-approved ROE of 9.36% on common equity and 4.79% on short-term debt, 4.3% forecast cost of long-term debt and 40/60 equity/debt split, and current enacted income tax rate of 26.5%

Please indicate which year of the OEB approved cost of capital parameters have applied in the calculations. The OEB issued the most recent 2026 cost of capital parameters on October 31, 2025. Please update the calculation with the 2026 cost of capital parameters. If the most recent cost of capital parameters should not be used, please explain why.

Response:

a) Please find an updated analysis reflecting the most recent 2026 UTRs that were issued after the filing of this Application at Attachment 1 of this Schedule.

b) Hydro One used the cost of capital parameters approved as part of Hydro One’s 2023-2027 approved rate order EB-2021-0110 (Attachment 1, Schedule 1.4, page 1 of 1). Hydro One’s revenue requirement, that underpins the UTRs (either 2025 UTRs or 2026 UTRs) would be using the EB-2021-0110 Hydro One approved cost of capital parameters. Furthermore, the most recent 2026 cost of capital parameters issued by the OEB on October 31, 2025 (EB-2025-0303) outlines the parameters are for "cost-based rate applications (cost of service and custom incentive rate-setting) with a proposed effective date commencing in 2026" not leave to construct applications.

Table 1 - Net Present Value, Network Pool page 1

			In-Service Date	<-------	Project year ended - annualized from In-Service Date	-------->									
		Month	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14
		Year	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast															
Load Forecast (MW)				145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Tariff Applied ($/kW/Month)				6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39
Incremental Revenue - $M				11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
Removal Costs - $M			0.0												
On-going OM&A Costs - $M			0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Municipal Tax - $M				(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)
Net Revenue/(Costs) before taxes - $M			0.0	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Income Taxes			0.0	0.2	2.9	2.4	2.0	1.7	1.4	1.1	0.8	0.5	0.3	0.0	(0.2)
Operating Cash Flow (after taxes) - $M			0.0	10.4	13.0	12.6	12.2	11.8	11.5	11.1	10.9	10.6	10.4	10.1	9.9
		Cumulative PV @ 5.65%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**142.7**	**0.0**	**10.1**	**12.0**	**11.0**	**10.1**	**9.2**	**8.5**	**7.8**	**7.2**	**6.6**	**6.1**	**5.7**	**5.3**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(262.5)												
- Overheads			(7.7)												
- AFUDC			(20.3)												
Total upfront capital expenditures			**(290.5)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(290.5)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**1.6**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	**(B)**	**(288.9)**	**(288.9)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(146.2)**	**(288.9)**	**(278.8)**	**(266.8)**	**(255.8)**	**(245.8)**	**(236.6)**	**(228.1)**	**(220.3)**	**(213.1)**	**(206.5)**	**(200.3)**	**(194.6)**	**(189.4)**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**
Discount Rate - %		**5.65%**
		$M
PV Incremental Revenue		151.9
PV OM&A Costs		(1.7)
PV Municipal Tax		(13.0)
PV Income Taxes		(36.4)
PV CCA Tax Shield		43.4
PV Capital - Upfront	(290.5)	
Add: PV **Capital Contribution**	**0.0**	(290.5)
PV Capital - On-going		0.0
PV Working Capital		(0.0)
PV Surplus / (Shortfall)		**(146.2)**
Profitability Index*		**0.5**

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Other Assumptions

In-Service Date:	14-Aug-29
Payback Year:	2054
No. of years required for payback:	25

Table 2 - Net Present Value, Network Pool, page 2

			<-------		Project year ended - annualized from In-Service Date			------->						
	Month	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14
	Year	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
		13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast														
Load Forecast (MW)		145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Tariff Applied ($/kW/Month)		6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39	6.39
Incremental Revenue - $M		11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
Removal Costs - $M														
On-going OM&A Costs - $M		(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Municipal Tax - $M		(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)
Net Revenue/(Costs) before taxes - $M		10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Income Taxes		(0.4)	(0.5)	(0.7)	(0.8)	(1.0)	(1.1)	(1.2)	(1.3)	(1.4)	(1.5)	(1.6)	(1.7)	(1.8)
Operating Cash Flow (after taxes) - $M		9.7	9.6	9.4	9.2	9.1	9.0	8.8	8.7	8.6	8.5	8.5	8.4	8.3
PV Operating Cash Flow (after taxes) - $M (A)		**4.9**	**4.5**	**4.2**	**3.9**	**3.7**	**3.4**	**3.2**	**3.0**	**2.8**	**2.6**	**2.5**	**2.3**	**2.2**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M (B)														
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)		**(184.5)**	**(179.9)**	**(175.7)**	**(171.8)**	**(168.1)**	**(164.7)**	**(161.5)**	**(158.5)**	**(155.7)**	**(153.1)**	**(150.6)**	**(148.3)**	**(146.2)**

Table 3 - Net Present Value, Transformation Connection Pool, page 1

			In-Service Date	<------- Project year ended - annualized from In-Service Date -------->											
		Month	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14
		Year	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast															
Load Forecast (MW)				145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Tariff Applied ($/kW/Month)				3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47
Incremental Revenue - $M				6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Removal Costs - $M			0.0												
On-going OM&A Costs - $M			0.0	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
Municipal Tax - $M				(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Net Revenue/(Costs) before taxes - $M			0.0	5.6	5.6	5.6	5.6	5.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Income Taxes			0.0	(0.7)	0.1	(0.0)	(0.2)	(0.3)	(0.3)	(0.4)	(0.5)	(0.5)	(0.6)	(0.7)	(0.7)
Operating Cash Flow (after taxes) - $M			0.0	4.9	5.7	5.5	5.4	5.3	5.0	4.9	4.9	4.8	4.7	4.6	4.6
		Cumulative PV @ 5.65%													
PV Operating Cash Flow (after taxes) - $M	(A)	**65.1**	**0.0**	**4.8**	**5.2**	**4.8**	**4.5**	**4.1**	**3.7**	**3.5**	**3.2**	**3.0**	**2.8**	**2.6**	**2.4**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(67.8)												
- Overheads			(1.4)												
- AFUDC			(7.3)												
Total upfront capital expenditures			**(76.5)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(76.5)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.4**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	**(B)**	**(76.1)**	**(76.1)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(11.0)**	**(76.1)**	**(71.3)**	**(66.1)**	**(61.3)**	**(56.8)**	**(52.7)**	**(49.0)**	**(45.5)**	**(42.3)**	**(39.3)**	**(36.5)**	**(33.9)**	**(31.5)**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**
Discount Rate - %		**5.65%**
		$M
PV Incremental Revenue		82.5
PV OM&A Costs		(6.2)
PV Municipal Tax		(3.4)
PV Income Taxes		(19.3)
PV CCA Tax Shield		11.9
PV Capital - Upfront	(76.5)	
Add: PV **Capital Contribution**	**0.0**	(76.5)
PV Capital - On-going		0.0
PV Working Capital		(0.0)
PV Surplus / (Shortfall)		**(11.0)**
Profitability Index*		**0.9**

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Other Assumptions

In-Service Date:	14-Aug-29
Payback Year:	2054
No. of years required for payback:	25

Table 4 - Net Present Value, Transformation Connection Pool, page 2

		<-------			Project year ended - annualized from In-Service Date			-------->						
Month		Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14
Year		2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
		13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast														
Load Forecast (MW)		145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Tariff Applied ($/kW/Month)		3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47
Incremental Revenue - $M		6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Removal Costs - $M														
On-going OM&A Costs - $M		(0.5)	(0.5)	(0.5)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)
Municipal Tax - $M		(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Net Revenue/(Costs) before taxes - $M		5.3	5.3	5.3	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Income Taxes		(0.8)	(0.8)	(0.9)	(0.9)	(0.9)	(1.0)	(1.0)	(1.0)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
Operating Cash Flow (after taxes) - $M		4.5	4.5	4.4	4.3	4.3	4.2	4.2	4.2	4.1	4.1	4.1	4.1	4.0
PV Operating Cash Flow (after taxes) - $M	**(A)**	**2.3**	**2.1**	**2.0**	**1.8**	**1.7**	**1.6**	**1.5**	**1.4**	**1.3**	**1.3**	**1.2**	**1.1**	**1.1**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(29.2)**	**(27.1)**	**(25.1)**	**(23.2)**	**(21.5)**	**(19.9)**	**(18.4)**	**(17.0)**	**(15.6)**	**(14.4)**	**(13.2)**	**(12.1)**	**(11.0)**

Table 5 - Revenue Requirement and Network Pool Rate Impact, page 1

Welland Thorold Power Line		Base Year	Project YE 14-Aug 2030	14-Aug 2031	14-Aug 2032	14-Aug 2033	14-Aug 2034	14-Aug 2035	14-Aug 2036	14-Aug 2037	14-Aug 2038	14-Aug 2039	14-Aug 2040	14-Aug 2041
Calculation of Incremental Revenue Requirement ($ millions)			1	2	3	4	5	6	7	8	9	10	11	12
In-service date	14-Aug-29													
Capital Cost	290.5													
Less: Capital Contribution Required	-													
Net Project Capital Cost	290.5													
Average Rate Base			142.4	281.9	276.1	270.3	264.6	258.8	253.1	247.3	241.5	235.8	230.0	224.3
Incremental OM&A Costs			0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Grants in Lieu of Municipal tax			1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Depreciation			5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Interest and Return on Rate Base			9.0	17.9	17.5	17.1	16.8	16.4	16.1	15.7	15.3	15.0	14.6	14.2
Income Tax Provision			0.1	(1.7)	(1.2)	(0.7)	(0.3)	0.1	0.4	0.7	1.0	1.3	1.5	1.7
REVENUE REQUIREMENT PRE-TAX			**15.9**	**23.0**	**23.1**	**23.2**	**23.3**	**23.3**	**23.3**	**23.3**	**23.2**	**23.1**	**22.9**	**22.8**
Incremental Revenue			11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
SUFFICIENCY/(DEFICIENCY)			**(4.7)**	**(11.8)**	**(11.9)**	**(12.0)**	**(12.1)**	**(12.2)**	**(12.1)**	**(12.1)**	**(12.0)**	**(11.9)**	**(11.8)**	**(11.6)**
Network Pool Revenue Requirement including sufficiency/(deficiency)		1,495	1,511	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518
Network MW		234	236	236	236	236	236	236	236	236	236	236	236	236
Network Pool Rate ($/kw/month)		6.39	6.41	6.44	6.44	6.44	6.45	6.45	6.45	6.45	6.44	6.44	6.44	6.44
Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year			0.02	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05
RATE IMPACT relative to base year			**0.31%**	**0.78%**	**0.78%**	**0.78%**	**0.94%**	**0.94%**	**0.94%**	**0.94%**	**0.78%**	**0.78%**	**0.78%**	**0.78%**

Assumptions		
Incremental OM&A		Years 1 to 5 0.0935603594749793% of Initial Capital each year; Years 6 to 15 0.187120718949959% of Initial Captial each year; Years 16 to 25 0.233900898687448% of Initial Capital each year.
Grants in Lieu of Municipal tax	0.33%	Transmission system average
Depreciation	2.00%	Reflects 50 year average service life for towers, conductors and station equipment, excluding land
Interest and Return on Rate Base	6.34%	Includes OEB-approved ROE of 9.36%, 4.79% on ST debt, and 4.3% on LT debt. 40/4/56 equity/ST debt/ LT debt split
Income Tax Provision	26.50%	2023 federal and provincial corporate income tax rate
Capital Cost Allowance	8.00%	86% Class 47 assets except for Land

Table 6 - Revenue Requirement and Network Pool Rate Impact, page 2

Welland Thorold Power Line		**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**
		2042	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**
Calculation of Incremental Revenue Requirement ($ millions)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	14-Aug-29													
Capital Cost	290.5													
Less: Capital Contribution Required	-													
Net Project Capital Cost	290.5													
Average Rate Base		218.5	212.7	207.0	201.2	195.5	189.7	183.9	178.2	172.4	166.7	160.9	155.1	149.4
Incremental OM&A Costs		0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Grants in Lieu of Municipal tax		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Depreciation		5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Interest and Return on Rate Base		13.9	13.5	13.1	12.8	12.4	12.0	11.7	11.3	10.9	10.6	10.2	9.8	9.5
Income Tax Provision		1.9	2.0	2.2	2.3	2.4	2.5	2.6	2.7	2.7	2.8	2.8	2.8	2.9
REVENUE REQUIREMENT PRE-TAX		**22.6**	**22.4**	**22.2**	**22.0**	**21.7**	**21.4**	**21.1**	**20.9**	**20.5**	**20.2**	**19.9**	**19.6**	**19.2**
Incremental Revenue		11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
SUFFICIENCY/(DEFICIENCY)		**(11.4)**	**(11.2)**	**(11.0)**	**(10.8)**	**(10.5)**	**(10.2)**	**(10.0)**	**(9.7)**	**(9.4)**	**(9.0)**	**(8.7)**	**(8.4)**	**(8.0)**
	Base Year													
Network Pool Revenue Requirement including sufficiency/(deficiency)	1,495	1,517	1,517	1,517	1,517	1,516	1,516	1,516	1,516	1,515	1,515	1,515	1,514	1,514
Network MW	234	236	236	236	236	236	236	236	236	236	236	236	236	236
Network Pool Rate ($/kw/month)	6.39	6.44	6.44	6.44	6.44	6.44	6.44	6.44	6.43	6.43	6.43	6.43	6.43	6.43
Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04
RATE IMPACT relative to base year		**0.78%**	**0.78%**	**0.78%**	**0.78%**	**0.78%**	**0.78%**	**0.78%**	**0.63%**	**0.63%**	**0.63%**	**0.63%**	**0.63%**	**0.63%**

Table 7 - Revenue Requirement and Transformation Connection Pool Rate Impact, page 1

		Project YE											
Welland Thorold Power Line		**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**
		2030	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Calculation of Incremental Revenue Requirement ($ millions)		1	2	3	4	5	6	7	8	9	10	11	12
In-service date	14-Aug-29												
Capital Cost	76.5												
Less: Capital Contribution Required	-												
Net Project Capital Cost	76.5												
Average Rate Base		37.5	74.2	72.7	71.1	69.6	68.1	66.6	65.0	63.5	62.0	60.4	58.9
Incremental OM&A Costs		0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Grants in Lieu of Municipal tax		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Depreciation		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Interest and Return on Rate Base		2.4	4.7	4.6	4.5	4.4	4.3	4.2	4.1	4.0	3.9	3.8	3.7
Income Tax Provision		(0.0)	(0.6)	(0.4)	(0.3)	(0.2)	(0.0)	0.1	0.1	0.2	0.3	0.4	0.4
REVENUE REQUIREMENT PRE-TAX		**4.4**	**6.2**	**6.2**	**6.3**	**6.3**	**6.6**	**6.6**	**6.6**	**6.5**	**6.5**	**6.5**	**6.4**
Incremental Revenue		6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
SUFFICIENCY/(DEFICIENCY)		**1.7**	**(0.1)**	**(0.1)**	**(0.2)**	**(0.2)**	**(0.5)**	**(0.5)**	**(0.5)**	**(0.5)**	**(0.4)**	**(0.4)**	**(0.4)**
	Base Year												
Transformation Pool Revenue Requirement including sufficiency/(deficiency)	663	667	669	669	669	669	669	669	669	669	669	669	669
Transformation MW	191	193	193	193	193	193	193	193	193	193	193	193	193
Transformation Pool Rate ($/kw/month)	3.47	3.46	3.47	3.47	3.47	3.47	3.48	3.48	3.48	3.48	3.48	3.48	3.48
Increase/(Decrease) in Transformation Pool Rate ($/kw/month), relative to base year		(0.01)	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
RATE IMPACT relative to base year		**-0.29%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**

Assumptions		
Incremental OM&A		Years 1 to 5 $251.344251023779 k each year; Years 6 to 15 $502.688502047558 k each year; Years 16 to 25 $628.360627559448 k each year.
Grants in Lieu of Municipal tax	0.33%	Transmission system average
Depreciation	2.00%	Reflects 50 year average service life for towers, conductors and station equipment, excluding land
Interest and Return on Rate Base	6.34%	Includes OEB-approved ROE of 9.36%, 4.79% on ST debt, and 4.3% on LT debt. 40/4/56 equity/ST debt/ LT debt split
Income Tax Provision	26.50%	2025 federal and provincial corporate income tax rate
Capital Cost Allowance	8.00%	100% Class 47 assets

Table 8 - Revenue Requirement and Transformation Connection Pool Rate Impact, page 2

Welland Thorold Power Line		14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug
		2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
Calculation of Incremental Revenue Requirement ($ millions)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	14-Aug-29													
Capital Cost	76.5													
Less: Capital Contribution Required	-													
Net Project Capital Cost	76.5													
Average Rate Base		57.4	55.8	54.3	52.8	51.3	49.7	48.2	46.7	45.1	43.6	42.1	40.5	39.0
Incremental OM&A Costs		0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Grants in Lieu of Municipal tax		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Depreciation		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Interest and Return on Rate Base		3.6	3.5	3.4	3.3	3.3	3.2	3.1	3.0	2.9	2.8	2.7	2.6	2.5
Income Tax Provision		0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8
REVENUE REQUIREMENT PRE-TAX		**6.4**	**6.4**	**6.3**	**6.4**	**6.3**	**6.2**	**6.2**	**6.1**	**6.0**	**5.9**	**5.8**	**5.7**	**5.7**
Incremental Revenue		6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
SUFFICIENCY/(DEFICIENCY)		**(0.3)**	**(0.3)**	**(0.2)**	**(0.3)**	**(0.2)**	**(0.2)**	**(0.1)**	**(0.0)**	**0.1**	**0.2**	**0.2**	**0.3**	**0.4**
	Base Year													
Transformation Pool Revenue Requirement including sufficiency/(deficiency)	663	669	669	669	669	669	669	669	669	669	669	668	668	668
Transformation MW	191	193	193	193	193	193	193	193	193	193	193	193	193	193
Transformation Pool Rate ($/kw/month)	3.47	3.48	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47
Increase/(Decrease) in Transformation Pool Rate ($/kw/month), relative to base year		0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RATE IMPACT relative to base year		**0.29%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**

Table 9 - DCF Assumption

Hydro One Networks -- Transmission Connection Economic Evaluation Model

Transmission rates are based on current OEB-approved uniform provincial transmission rates.

Monthly Rate ($ per kW)	
Network	**6.39**
Transformation	**3.47**
Line	**1.03**

Grants in lieu of Municipal tax (% of up-front capital expenditure, a proxy for property value):		**0.33%**	Based on Transmission system average
Income taxes:			
Basic Federal Tax Rate - % of taxable income:	2023	**15.00%**	Current rate
Ontario corporation income tax - % of taxable income:	2023	**11.50%**	Current rate
Capital Cost Allowance Rate:			
Class 47 costs	2023	**8%**	Current rate
Easement rights	2023	**5%**	
Decision Support defined costs (2)	2023	**0%**	
Decision Support defined costs (3)	2023	**0%**	
After-tax Discount rate:		**5.65%**	Based on OEB-approved ROE of 9.36% on common equity and 4.79% on short-term debt, 4.3% forecast cost of long-term debt and 40/60 equity/debt split, and current enacted income tax rate of 26.5%

OEB STAFF INTERROGATORY - 22

Reference:

1. Exhibit B-9-1, Page 3
2. Exhibit B-9-1, Pages 8-9
3. Exhibit B-9-1, Pages 12-13

Preamble:

Reference 1 states "Welland Hydro will be responsible for the incremental costs associated with the increased station load capacity, representing the difference between rebuilding the existing 115 kV 83 MVA station and constructing a new 230kV 125 MVA station. However, based on the transformation connection pool discounted cash flow provided at Table 7 of this Schedule, Welland Hydro will not be required to make a capital contribution because forecast future revenue will offset the cost."

Table 7 (Reference 3) does not provide a discounted cash flow analysis as described in Reference 1. Reference 2 does provide a discounted cash flow analysis but does not break out incremental costs from total project station costs.

Interrogatory:

a) What is the amount of the incremental costs associated with the increased station load capacity (representing the difference between rebuilding the existing 115 kV 83 MVA station and constructing a new 230 kV 125 MVA station)?

b) Please provide the discounted cash flow analysis which forms the basis of the conclusion that forecast future revenue will offset incremental capital costs.

Response:

a) The incremental cost associated with the increased station load capacity is $3.5M. Rebuilding the existing 115kV 83MVA station would not provide enough capacity for the forecast load demand at Crowland TS and was dismissed as being a viable alternative in the Regional Infrastructure Plan (RIP) provided at Exhibit H, Tab 1, Schedule 1, Attachment 1.[1] As detailed in Exhibit I, Tab 1, Schedule 18, part b, absent the Project an additional 83MVA station would need to be built to accommodate the forecasted load demand in concert with rebuilding the existing station. Based on the forecast cost provided in the RIP, this is estimated to be an incremental cost of $78M for the refurbishment work and additional station at Crowland TS. Given the cost-effective solution provided by the Project, the incremental cost attributed to the

[1] Exhibit H, Tab 1, Schedule 1, Attachment 1 - p.34-36

increased station load capacity is limited to Welland Hydro facilities with a forecast cost of only \$3.5M. Over a revenue horizon period of 25 years, this cost is fully offset by forecast revenues.

b) Please refer to Attachment 1 of this Schedule.

hydro one

Date:	16-Mar-26
Project #	26503

SUMMARY OF REVENUE GUARANTEE
Transformation Pool - Estimated cost

Facility Name:	Crowland TS - New station
Description:	New Crowland 230kV Station - upgrade cost
Customer:	Welland Hydro

<---- Project year ended - annualized from In-Service Date ---->

		In-Service Date												
	Month	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14
	Year	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
							1st true-up					*2nd true-up*		
		0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast														
Load Forecast (MW)			2.5	3.0	3.6	4.1	4.7	5.3	6.0	6.6	7.2	7.9	8.5	9.1
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			2.5	3.0	3.6	4.1	4.7	5.3	6.0	6.6	7.2	7.9	8.5	9.1
Tariff Applied ($/kW/Month)			3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39
Incremental Revenue - $k			100.9	124.0	146.3	168.9	192.2	216.8	242.4	268.3	294.2	320.0	345.6	370.6
Removal Costs - $k		0.0												
On-going OM&A Costs - $k		0.0	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(23.0)	(23.0)	(23.0)	(23.0)	(23.0)	(23.0)	(23.0)
Municipal Tax - $k			(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)
Net Revenue/(Costs) before taxes - $k		0.0	77.9	101.0	123.3	145.9	169.2	182.3	207.9	233.8	259.7	285.5	311.1	336.1
Income Taxes - $k		0.0	16.5	44.5	32.9	21.6	10.6	2.7	(8.2)	(18.8)	(29.1)	(39.1)	(48.8)	(58.1)
Operating Cash Flow (after taxes) - $k		0.0	94.4	145.5	156.1	167.5	179.8	185.0	199.8	215.1	230.6	246.4	262.3	278.0
	Cumulative PV @ 5.65%													
PV Operating Cash Flow (after taxes) - $k (A)	3,482.4	**0.0**	**91.8**	**134.0**	**136.1**	**138.2**	**140.4**	**136.7**	**139.7**	**142.4**	**144.5**	**146.1**	**147.2**	**147.7**
Capital Expenditures - $k														
Capital cost before overheads & AFUDC - $k		(3,500.0)												
- Overheads - $k		0.0												
- AFUDC - $k		0.0												
Total upfront capital expenditures - $k		**(3,500.0)**												
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0												
Total capital expenditures - $k		**(3,500.0)**												
PV CCA Residual Tax Shield - $k		**17.8**												
PV Working Capital - $k		**(0.2)**												
PV Capital (after taxes) - $k (B)	**(3,482.4)**	**(3,482.4)**												
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	**0.0**	**(3,482.4)**	**(3,390.6)**	**(3,256.6)**	**(3,120.5)**	**(2,982.4)**	**(2,842.0)**	**(2,705.2)**	**(2,565.5)**	**(2,423.1)**	**(2,278.6)**	**(2,132.5)**	**(1,985.3)**	**(1,837.6)**

Month	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14
Year	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**
			3rd true-up										
	13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast													
Load Forecast (MW)	9.7	10.3	10.9	11.6	12.2	12.9	13.5	14.2	14.9	15.6	16.3	17.1	17.8
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	9.7	10.3	10.9	11.6	12.2	12.9	13.5	14.2	14.9	15.6	16.3	17.1	17.8
Tariff Applied ($/kW/Month)	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39
Incremental Revenue - $k	394.8	419.5	445.0	470.7	496.9	523.5	550.6	578.1	605.9	634.8	664.6	694.9	725.6
On-going OM&A Costs - $k	(23.0)	(23.0)	(23.0)	(28.7)	(28.7)	(28.7)	(28.7)	(28.7)	(28.7)	(28.7)	(28.7)	(28.7)	(28.7)
Municipal Tax - $k	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)
Net Revenue/(Costs) before taxes - $k	360.3	385.0	410.5	430.5	456.7	483.3	510.4	537.9	565.7	594.6	624.4	654.7	685.4
Income Taxes - $k	(67.0)	(75.8)	(84.7)	(91.9)	(100.6)	(109.3)	(118.0)	(126.7)	(135.3)	(144.1)	(153.1)	(162.1)	(171.2)
Operating Cash Flow (after taxes) - $k	293.3	309.2	325.8	338.6	356.1	374.0	392.4	411.2	430.4	450.4	471.3	492.6	514.2
PV Operating Cash Flow (after taxes) - $k (A)	**147.5**	**147.1**	**146.7**	**144.3**	**143.7**	**142.8**	**141.8**	**140.7**	**139.4**	**138.0**	**136.7**	**135.2**	**133.6**
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	**(1,690.2)**	**(1,543.1)**	**(1,396.3)**	**(1,252.0)**	**(1,108.3)**	**(965.5)**	**(823.7)**	**(683.0)**	**(543.6)**	**(405.6)**	**(268.9)**	**(133.6)**	**0.0**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**
Discount Rate - %		**5.65%**
		$k
PV Incremental Revenue		4,460.9
PV OM&A Costs		(281.5)
PV Municipal Tax		(156.2)
PV Income Taxes		(1,066.2)
PV CCA Tax Shield		543.1
PV Capital - Upfront	(3,500.0)	
Add: PV **Capital Contribution**	**0.0**	(3,500.0)
PV Capital - On-going		0.0
PV Working Capital		(0.2)
PV Surplus / (Shortfall)		**0.0**
Profitability Index*		**1.0**

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Other Assumptions		**Notes:**
In-Service Date:	14-Aug-29	
Municipal Tax	0.33%	Transmission system average
Federal Income Tax	15.00%	2024 federal corporate income tax
Ontario Corporation Income Tax	11.50%	2024 provincial corporate income tax
Working cash net lag days	5.8	As per Lead Lag Study as prepared by Navigant for 2023-2027 rates
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 16-Mar-26, 10:12 AM

OEB STAFF INTERROGATORY - 23

Reference:
Exhibit B-10-1, Page 2

Preamble:
The Reference states that the transmission line costs of the Project are anticipated to be captured and tracked in the Affiliate Transmission Partnership Regulatory Deferral and Variance Account (ATP Account), which will be disposed of during a future rate hearing for the new partnership.

Interrogatory:
a) Has the new partnership been formed? Please provide a current update on the establishment of the new limited partnership.

b) When does Hydro One anticipate the transmission line costs to be included in the rate base, and when is the revenue requirement application of the new partnership expected to be filed?

Response:
a) No, the new partnership has not been formed. As negotiations are still ongoing, Hydro One cannot provide commercial details at this time. Details will be provided to the OEB once the partnership is formed.

b) The in-service date of the Project will inform the timing of the related forecast revenue requirement application filing with the OEB for the future affiliate transmission partnership entity that will own the transmission line component of the Project. Any material advancement or delay of the forecast in-service date provided in Exhibit B, Tab 11, Schedule 1, will similarly advance or delay the forecast revenue requirement application.

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OEB STAFF INTERROGATORY - 24

Reference:
Exhibit C-1-1, Pages 2-3

Preamble:
The two new 230 kV circuits will have a continuous ampacity of 1132.2 A, and the new 115 kV circuit will have a continuous ampacity of 499.6 A.

Interrogatory:

a) How does the continuous ampacity of the two new 230 kV circuits compare to that of the main trunk of the Q24HM/Q29HM circuits it is tapping off?

b) How does the continuous ampacity of the new 115 kV circuit compare to that of the D3A/A3C circuits it is replacing?

Response:

a) The two new 230kV circuits have a higher continuous ampacity compared to Q24HM/Q29HM. This is to enable future development in the area.

b) The technical solution to constrain the triple circuit within a 30m right of way requires the same conductor for all three circuits. All three circuits on Section B will utilize the same conductor. Therefore, the continuous ampacity of the Section B portion of the permanent 115kV circuit will be 1132.2 A. The remaining portions of D3A will remain unchanged and the overall ampacity will be unaffected by the project. The continuous ampacity of the temporary 115kV circuit will remain the same as the same sized conductor will be installed.

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OEB STAFF INTERROGATORY - 25

Reference:
Exhibit E-1-1, Pages 4-5, Table 2

Preamble:
The Reference states that Hydro One has been meeting with affected property owners since April 2025, and Hydro One will continue working with each property owner with the objective of reaching voluntary settlements. Hydro One also provide a summary of all land negotiation status in Table 2 of Exhibit E-1-1:

Property Type	Number of Properties	Early Access Agreement Offered	Early Access Agreement Achieved	Voluntary Settlement Agreements Offered	Voluntary Settlement Agreements Achieved
Private Lands	46	100%	78%	0	0
Federal Lands	3	N/A	N/A	0	0
Provincial Lands	6	N/A	N/A	0	0
Municipal Lands	7	N/A	N/A	0	0
Railway Lands	3	N/A	N/A	0	0

Interrogatory:

a) Please update Table 2 with up-to-date information. For how many impacted private properties has Hydro One reached early access agreements and voluntary settlement agreements respectively?

b) Please provide an up-to-date summary of all land and rights acquisitions processes, including their current status, any contentious issues and the proposed approach to resolution.

c) Please confirm that all impacted landowners will have the option to receive independent legal advice regarding the proposed agreements.

d) Please clarify whether Hydro One has committed to or will commit to reimbursing landowners for reasonably incurred legal fees associated with the review and completion of the necessary land rights agreements.

e) How does Hydro One advise affected property owners of the availability of independent legal advice (ILA) and that Hydro One will reimburse landowners for the expense of obtaining ILA? Is this information communicated to property owners orally or in writing? If the latter, please provide a copy of the document.

Response:

a) Please refer to the updated table below.

Property Type	Number of Properties	Early Access Agreement Offered	Early Access Agreement Achieved	Voluntary Settlement Agreements Offered	Voluntary Settlement Agreements Achieved
Private Lands	46	100%	78%	8	2
Federal Lands	3	N/A	N/A	3	0
Provincial Lands	6	N/A	N/A	N/A	0
Municipal Lands	7	N/A	N/A	0	0
Railway Lands	3	N/A	N/A	3	0

The project schedule, provided at Exhibit B, Tab 11, Schedule 1, was based on standard leave to construct processing timelines[1] and as a result of the protracted nature of this proceeding, and Procedural Order's #2, whereby the OEB established that the proposed concurrent leave to construct and expropriation authorization relief was not permissible, Hydro One is shifting the land acquisition strategy from pursuing option agreements to presenting an Agreement of Purchase and Sale with a signing bonus if exercised prior to June 30, 2026 . The aim of the land acquisition shift will be to accelerate the land acquisition process so that Project timelines are maintained by minimizing the need for expropriation relief. This change in approach is not expected to increase forecast costs. A copy of the proposed Agreement of Purchase and Sale is provided as Attachment 1 of this Schedule.

b) Effective March 16, 2026, Hydro One began making offer presentations based on Hydro One's Land Acquisition Compensation Principles ("LACP")[2] to impacted land owners. As detailed in the proceeding to date, any contentious issues have been regarding routing. To mitigate these concerns, where no transmission corridor existed previously, Hydro One has provided technical routing workshops with impacted landowners to help provide technical solutions to mitigate land impacts wherever possible. In situations where landowners object or are hesitant to continue discussions, Hydro One seeks to address and resolve outstanding matters at time of

[1] OEB Letter to Industry re: Updates to Performance Standards and Other Process Improvements – Appendix B – pg. i
[2] Provided as Attachment 2 of this Schedule.

presenting the formal offer. Hydro One's LACP is intended to ensure that compensation is fair, transparent and with the objective of ensuring landowners are whole.

c) All impacted landowners will have the option to receive their own independent legal advice regarding the proposed agreements, which Real Estate Representatives encourages landowners to seek to ensure and promote equity.

d) Hydro One has agreed to reimburse all impacted landowners for reasonable transaction expenses such as legal fees incurred during the review and completion of required conveyancing of documents.

e) The commitment for Hydro One to agree to reimburse all impacted landowners for reasonable transaction expenses such as legal fees incurred during the review and completion of the required conveyance of documents is conveyed both orally and in writing. This commitment is outlined in the LACP booklet that is provided to all private impacted that Property Owners received on or around the landowner engagement which commenced after the announcement of the Preferred Route in May 2025. Please refer to Attachment 2 for a copy of Hydro One's LACP.

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AGREEMENT TO PURCHASE A LIMITED INTEREST - EASEMENT

THIS AGREEMENT made as of the ______ day of________________, 202__ (the "**Agreement Date**").

B E T W E E N:

(hereinafter collectively called the "**Owner**")

OF THE FIRST PART

- and –

HYDRO ONE NETWORKS INC.

(hereinafter called "**Hydro One**")

OF THE SECOND PART

- and -

SPOUSE NAME

(hereinafter collectively called the "**Spouse**") This section is only filled if the spouse is not on title

OF THE THIRD PART

WITNESSETH THAT in consideration of the mutual covenants, agreements and payments herein provided, the parties hereto covenant and agree as follows:

ARTICLE 1
OFFER

1.1 The Owner, being the owner of the lands and premises more particularly described in Schedule "A" (the "Lands") hereby agrees to sell to Hydro One and Hydro One agrees to purchase from the Owner, on the terms and conditions set out in this Agreement, a limited interest in the form of a right-of-way and easement in, on, over, under, across and through (the "Easement") that portion of the Lands described on Schedule "A-1" attached hereto (the "Easement Lands"), the terms of which Easement are more particularly set out in the Transfer and Grant of Easement (the "Easement Agreement") attached hereto as Schedule "B" upon and subject to the terms and conditions hereinafter set forth.

1.2 The Owner acknowledges and understands that upon execution of this Agreement by the Owner and Hydro One there shall be a binding Agreement of Purchase and Sale between Hydro One and the Owner.

ARTICLE 2
PURCHASE PRICE

2.1 Provided that the Owner executes this Agreement To Purchase A Limited Interest – Easement by June 30, 2026, Hydro One shall pay to or to the order of Owner, on the Closing Date, a signing bonus, which amount shall be the greater of either TEN THOUSAND DOLLARS ($10,000.00) or twenty five percent (25%) of the Fee Simple Rate

Per Acre (as shown on Schedule "C") multiplied by the area of the Easement Lands (the "**Early Acceptance Bonus**").

2.2 (a) The total compensation to be paid by Hydro One to the Owner for the Easement Lands shall be the sum of **XXX ($XXXXX)** Canadian Dollars, (the "Total Compensation") subject to usual adjustments, if any, payable on Closing by uncertified cheque or electronic funds transfer.

(b) The Total Compensation is comprised the Early Acceptance Bonus, if applicable and the following:

(i) Purchase Price of the Easement (the "Purchase Price):	**$XXX**
(ii) IA Compensation	**$XXXX**
(iii) 25% Premium Above Fair Market Value Incentive Payment	**$XXXX**
(iv) Acceptance of the Hydro One Offer Payment	**$XXXX**
TOTAL COMPENSATION	**$XXXXXX**

2.3 The Owner acknowledges receipt of an appraisal report and update, if any, prepared by an external, independent appraiser with the Accredited Appraiser Canadian Institute ("AACI") designation commissioned by Hydro One.

2.4 The parties acknowledge that the Purchase Price is based on a purchase price per acre as set out in Schedule "C" attached hereto and the actual area of the Easement Lands shall be confirmed by a survey to be prepared by Hydro One in accordance with section 2.7 herein, and in the event the surveyed area of the Easement Lands is greater than as provided for in Schedule "C" attached hereto, and Purchase Price shall be adjusted accordingly.

2.5 Hydro One agrees to pay to or to the order of the Owner, on the Closing Date, compensation for injurious affection (the "IA Compensation"), if applicable, in the amount of **XXXXX ($XX)** as set out in Schedule "C".

2.6 Hydro One shall pay to the Owner the following incentive payments:

(a) On the Closing Date, Hydro One shall make an incentive payment to or to the order of the Owner in the amount of XXXXX DOLLARS ($XX) (the "Acceptance of the Hydro One Offer") as set out on the Calculation Sheet.

(b) On the Closing Date, Hydro One shall make a further incentive payment to or to the order of the Owner in the amount of XXXXX ($XX), (the "Premium Above Fair Market Value") such amount being equal to 25% of the appraised fair market value of the Owner's fee simple interest in the Easement Lands as set out on the Calculation Sheet.

2.7 Hydro One agrees to obtain and register, at its sole expense, any new Reference Plan with respect to the Easement Lands that may be required by Hydro One for completion of this Agreement To Purchase A Limited Interest – Easement.

2.8 The calculation of each item comprising the Total Compensation is shown on the calculation sheet attached hereto as Schedule "C".

ARTICLE 3
CLOSING

3.1 The transaction of purchase and sale contemplated by this Agreement shall, subject to resolution of any title issues identified by Hydro One, be completed on the date that is ninety (90) days after Hydro One delivers notice to the Owner that a reference plan has been deposited to described the Easement Lands satisfactory to Hydro One or such earlier date as the parties may mutually agree in writing (the **"Closing Date"**). If the Closing Date is a date on which the Land Registry Office (the **"Land Registry Office"**) in which the Lands are registered is closed, the Closing Date shall be on the next following day when such Land Registry Office is open. In the event that there is a delay in the completion of the transaction beyond the Closing Date as established by Hydro One upon delivery of the Exercise Notice that arises through no fault of Hydro One, then Hydro One shall not be responsible for any resulting delay in the Closing Date. Hydro One agrees to proceed with the preparation and deposit of a reference plan to describe the Easement Lands as soon as possible upon execution of this Agreement by the Owner.

On Closing,

(a) Hydro One shall pay the Total Compensation, to the Owner in accordance with section 2.2 of this Agreement.

(b) The Owner and Hydro One acknowledge and agree that the grant of easement contemplated under this Agreement constitutes a purchase and sale transaction of an interest in real property, and therefore, in conformance with subsections 221(2) and 228(4) of the *Excise Tax Act* R.S.C. 1985, c E-15, as amended ("the Act"), Hydro One shall report and pay to the Receiver General for Canada the Harmonized Sales Tax ("HST") applicable to the purchase and sale of the Easement. For the purposes of this section 11, Hydro One shall warrants that it is an HST registrant in good standing under the Act, that its HST registration number is 870865821RT0001, and that it is acquiring the Easement for use primarily in the course of its commercial activities.

ARTICLE 4
INSPECTION PERIOD AND EARLY CONSTRUCTION PERIOD

4.1

(a) The Owner agrees and consents to Hydro One, its respective officers, employees, agents, contractors, sub-contractors, surveyors, workers and permittees or any of them entering on, exiting and passing and repassing in, on, over, along, upon, across, through and under the Easement Lands and so much of the Lands as may be reasonably necessary at all reasonable times from the date of this Agreement until the Closing Date, with or without all plant, machinery, material, supplies, vehicles, and equipment, for all purposes necessary or convenient to conduct such inspections, tests, audits, reports as Hydro One sees fit in connection with the acquisition, exercise or enjoyment of the Easement. Hydro One shall restore the Lands to their prior condition so far as reasonably possible following such inspections, tests, audits and reports.

(b) The Owner agrees and consents to Hydro One, its respective officers, employees, agents, contractors, sub-contractors, surveyors, workers and permittees or any of them entering on, exiting and passing and repassing in, on, over, along, upon, across, through and under the Easement Lands and so much of the Lands as may be as reasonably necessary at all reasonable times starting on the Agreement Date to commence construction activities on the Easement Lands. Hydro One shall repair any physical damage to the Lands resulting from its exercise of this right of entry over the Lands.

ARTICLE 5
TITLE

5.1 The Owner covenants and agrees with Hydro One that it has the right to grant the Easement without restriction and that Hydro One will quietly possess and enjoy the Easement Lands.

5.2 The Owner covenants and agrees with the Purchase that the Owner shall not grant, create or transfer any easement, right, covenant, restriction, privilege, permission, or other agreement in, through, under, over or in respect of the Easement Lands prior to the registration of the Easement without the prior written consent of Hydro One.

5.3 The Owner hereby grants Hydro One permission, should Hydro One elect in its sole discretion, to approach any encumbrancer having an interest in the Easement Lands in priority to the Easement and to obtain (in registrable form) and register all necessary consents, postponements or subordinations from all current and future encumbrancers having an interest in the Easement Lands in priority to the Easement consenting, postponing or subordinating such encumbrance and their respective rights, title and interest to the Easement or to place the Easement in first priority on title to the Easement Lands.

ARTICLE 6
REGISTRATION OF EASEMENT

6.1 The Owner and, if applicable, the Spouse, acknowledge and agree that they shall execute the Acknowledgement and Direction attached as Schedule "D" to this Agreement (the "**Acknowledgement and Direction**"), which Acknowledgement and Direction authorizes Hydro One and its solicitors to register the Easement on title to the Lands. Hydro One covenants and agrees to hold the Acknowledgement and Direction in escrow until Hydro One has paid the Purchase Price at which time the executed Acknowledgement and Direction and Easement shall be released from escrow and may be acted upon by Hydro One

6.2 The Owner acknowledges and agrees that Hydro One will register the Easement on title to the Lands on the day of the Closing pursuant hereto and the Acknowledgement and Direction. Hydro One will provide notice to the Owner within a reasonable period of time after the Closing of the registration particulars of the Easement.

ARTICLE 7
PLANNING ACT

7.1 This Agreement is subject to the express condition that it is to be effective only if the provisions of the *Planning Act of Ontario* and amendments thereto are complied with.

ARTICLE 8
ADDITIONAL PROVISIONS

8.1 Time shall in all respects be of the essence hereof provided that the time for doing or completing of any matter provided for herein may be extended or abridged by an agreement in writing signed by the Parties or by their respective solicitors who are specifically authorized in that regard.

8.2 Any tender of documents or money hereunder may be made upon the Parties or their respective solicitors on the day set for Closing. Money may be tendered by uncertified cheque.

8.3 Notices to be given to either party shall be in writing, personally delivered or sent by registered mail (except during a postal disruption or threatened postal disruption), telegram, electronic facsimile or other similar means of prepaid recorded communication to the applicable address set forth below (or to such other address as such party may from time to time designate in such manner):

HYDRO ONE:

Hydro One Networks Inc.
Facilities and Real Estate
P.O. Box 4300
Markham, Ontario L2R 5Z5

185 Clegg Road
Markham, Ontario L3G 1B7

Attention: Real Estate Manager
Fax: (905) 946-6242

with a copy to its solicitors,

Barriston LLP
151 Ferris Lane, Suite 202
Barrie, ON L4M 6C1

Attention: Jim McIntosh
Fax: (705) 721-4025

OWNER:

Tel:
Email:

with a copy to their solicitors,

Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5th) business day following the date on which it was sent. Any notice sent by telegram, electronic facsimile or other similar means of prepaid recorded communication shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. "Business Day" shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario.

8.4 The parties acknowledge that there are no covenants, representations, warranties, agreements or conditions, express or implied, collateral or otherwise, forming part of or in any way affecting or relating to this Agreement to Purchase a Limited Interest save as expressly set out in this Agreement to Purchase a Limited Interest and that this Agreement to Purchase a Limited Interest and all Schedules hereto constitute the entire agreement between the parties and may not be modified except as expressly agreed between the Owner and Purchaser in writing. This Agreement shall be read with all changes of gender or number required by the context.

8.5 If any provision or provisions of this Agreement to Purchase a Limited Interest be declared illegal or unenforceable, it or they shall be considered separate and severable from the Agreement to Purchase a Limited Interest and its remaining provisions shall remain in force and be binding upon the parties hereto as though the said provision or provisions had never been included.

8.6 No act or omission or delay in exercising any right or enforcing any term, covenant or agreement to be performed under this Agreement to Purchase a Limited Interest shall impair such right or be construed as to be a waiver of any default or acquiescence in such failure to perform, unless such waiver shall be given or acknowledged in writing.

8.7 This Agreement to Purchase a Limited Interest shall be governed by and construed in accordance with the laws of the Province of Ontario.

8.8 This Agreement to Purchase a Limited Interest shall enure to the benefit of and be binding upon the parties hereto and their respective heirs, attorneys, guardians, estate trustees, executors, trustees, successors and permitted assigns.

8.9 The Owner warrants that, except to the extent such consent has been obtained, spousal consent is not necessary to this transaction and on Closing will not be necessary under the provision of the *Family Law Act*, R.S.O. 1990.

8.10 Hydro One may, in its sole discretion and at its sole expense register this Agreement to Purchase a Limited Interest or notice thereof on title to the Lands.

8.11 The provisions of the attached Schedules "A", "A-1", "B", "C" and "D" shall form part of this Agreement as if set out herein.

8.12 Hydro One agrees, at the Owner's written request, to take all necessary precautions to maintain the confidentiality of the terms and conditions contained herein.

8.13 The Owner represents and warrants and covenants that the Owner is not now and on Closing will not be a non-resident of Canada within the meaning of the *Income Tax Act (Canada)*.

8.14 Hydro One shall have the right to assign all or any part of its interest in this Agreement to Purchase a Limited Interest and any or all rights, privileges and benefits accruing to Hydro One hereunder without the consent of the Owner prior to or on the Closing. Upon and to the extent of such assignment, this Agreement to Purchase a Limited Interest shall thenceforth be construed as if originally made with such assignee or assignees instead of Hydro One and Hydro One shall, to the extent of such assignment, thereupon be relieved of all liabilities and obligations whatsoever arising out of this Agreement to Purchase a Limited Interest.

8.15 The parties hereto agree that any representations or covenants contained in this Agreement to Purchase a Limited Interest shall not merge on closing, but survive and continue in full force and effect thereafter, but only as to the accuracy of the representation or covenant as at the date of completion of this Agreement to Purchase a Limited Interest.

8.16 This Agreement to Purchase a Limited Interest may be executed in one or more counterparts, each of which shall be deemed an original and together shall constitute one and the same agreement. Counterparts may be executed either in original or by electronic means, including, without limitation, by facsimile transmission or by electronic delivery in portable document format (".pdf") or tagged image file format (".tif") and the parties shall adopt any signatures received by electronic means as original signatures of the Parties; provided, however that any party providing its signature in such manner shall promptly forward to the other party an original signed copy of this Agreement which was so delivered electronically

8.17 The Owner covenants and agrees to execute if necessary, at no further cost or condition to Hydro One except payment of the Owner's reasonable out-of-pocket costs, such other instruments, plans and documents as may reasonably be required by Hydro One to effect the registration of the Easement or notice of this Agreement to Purchase a Limited Interest on title to the Lands.

8.18 The Owner represents that the Owner is at least 18 years of age.

IN WITNESS WHEREOF the parties hereto have duly executed this Agreement to Purchase a Limited Interest as of the Agreement Date noted above.

WITNESS:	**OWNER:**
	l/s
Name:	Name:
Address:	
	l/s
Name:	Name:
Address:	
	l/s
Name:	Name:
Address:	
WITNESS:	The spouse of the Owner hereby consents to this Agreement
	SPOUSE OF OWNER:
	l/s
Name:	Name:
Address:	

Per: ____________________
Name:
Title:

We/I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ____________________
Name:
Title:

I have authority to bind the Corporation

SCHEDULE "A"
LEGAL DESCRIPTION

SCHEDULE "A-1"
EASEMENT LANDS

Insert Ortho Map

Legal description to be determined by deposited Reference Plan; Easement Lands shown outlined in green.

****NOTE – Sketch shall be replaced by legal description of servient lands once applicable Reference Plan is deposited.**

SCHEDULE "B"
TRANSFER AND GRANT OF EASEMENT IN GROSS

(the "**Transferor**") is the owner in fee simple and in possession of the Lands legally described as **LEGAL DESCRIPTION** being PIN **XXXXXXXXX**(LT) (the "**Lands**").

Hydro One Networks Inc. (the "**Transferee**") has erected, or is about to erect, certain Works (as more particularly described in paragraph 1(a) hereof) in, through, under, over, across, along and upon the Lands.

1. The Transferor hereby grants and conveys to the Transferee, its successors and assigns the rights and easement, free from all encumbrances and restrictions, the following unobstructed rights, easements, rights-of-way, covenants, agreements and privileges in perpetuity (the "**Rights**") in, through, under, over, across, along and upon that portion of the Lands of the Transferor described herein as ● and described as Part ● on Reference Plan ● hereto annexed (the "**Strip**"), for the following purposes:

   (a) To enter and lay down, install, construct, erect, maintain, open, inspect, add to, enlarge, alter, repair and keep in good condition, move, remove, replace, reinstall, reconstruct, relocate, supplement and operate and maintain at all times in, through, under, over, across, along and upon the Strip an electrical transmission systems and telecommunications systems consisting in both instances of pole structures, steel towers, anchors, guys and braces and all such aboveground or underground lines, wires, cables, telecommunications cables, grounding electrodes, conductors, apparatus, works, accessories, associated material and equipment, and appurtenances pertaining to or required by either such system (all or any of which are herein individually or collectively called the ("Works") as in the opinion of the Transferee are necessary or convenient thereto for use as required by Transferee in its undertaking from time to time, or a related business venture.

   (b) To enter on and selectively cut or prune, and to clear and keep clear, and remove all trees (subject to compensation to Transferor for merchantable wood values), branches, bush and shrubs and other obstructions and materials in, over or upon the Strip, and without limitation, to cut and remove all leaning or decayed trees located on the Lands whose proximity to the Works renders them liable to fall and come in contact with the Works or which may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

   (c) To conduct all engineering, legal surveys, and make soil tests, soil compaction and environmental studies and audits in, under, on and over the Strip as the Transferee in its discretion considers requisite.

   (d) To erect, install, construct, maintain, repair and keep in good condition, move, remove, replace and use bridges and such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary.

   (e) Except for fences and permitted paragraph 2(a) installations, to clear the Strip and keep it clear of all buildings, structures, erections, installations, or other obstructions of any nature (hereinafter collectively called the "**obstruction**") whether above or below ground, including removal of any materials and equipment or plants and natural growth, which in the opinion of the Transferee, endanger its Works or any person or property or which may be likely to become a hazard to any Works of the Transferee or to any persons or property or which do or may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

   (f) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for the Transferee, its employees, agents, contractors, subcontractors, workmen and permittees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or convenient to the exercise and enjoyment of this easement, subject to compensation afterwards for any crop or other physical damage only to the Lands or permitted structures sustained by the Transferor caused by the exercise of this right of entry and passageway.

(g) To remove, relocate and reconstruct the line on or under the Strip subject to payment by the Transferee of additional compensation for any damage caused thereby.

2. The Transferor agrees that:

(a) It will not interfere with any Works established on or in the Strip and shall not, without the Transferee's consent in writing erect or cause to be erected or permit in, under or upon the Strip any obstruction or plant or permit any trees, bush, shrubs, plants or natural growth which does or may interfere with the Rights granted herein. The Transferor agrees it shall not, without the Transferee's consent in writing, change or permit the existing configuration, grade or elevation of the Strip to be changed and the Transferor further agrees that no excavation or opening or work which may disturb or interfere with the existing surface of the Strip shall be done or made unless consent therefore in writing has been obtained from Transferee, provided however, that the Transferor shall not be required to obtain such permission in case of emergency. Notwithstanding the foregoing, in cases where in the reasonable discretion of the Transferee, there is no danger or likelihood of danger to the Works of the Transferee or to any persons or property and the safe or serviceable operation of this easement by the Transferee is not interfered with, the Transferor may at its expense and with the prior written approval of the Transferee, construct and maintain roads, lanes walks, drains, sewers water pipes, oil and gas pipelines, fences (not to exceed 2 metres in height) and service cables on or under the Strip (the "Installation") or any portion thereof; provided that prior to commencing such Installation, the transferor shall give to the Transferee thirty (30) days notice in writing thereof to enable the Transferee to have a representative present to inspect the proposed Installation during the performance of such work, and provided further that Transferor comply with all instructions given by such representative and that all such work shall be done to the reasonable satisfaction of such representative. In the event of any unauthorised interference aforesaid or contravention of this paragraph, or if any authorised interference, obstruction or Installation is not maintained in accordance with the Transferee's instructions or in the Transferee's reasonable opinion, may subsequently interfere with the Rights granted herein, the Transferee may at the Transferor's expense, forthwith remove, relocate, clear or correct the offending interference, obstruction, Installation or contravention complained of from the Strip, without being liable for any damages cause thereby.

(b) Notwithstanding any rule of law or equity, the Works installed by the Transferee shall at all times remain the property of the Transferee, notwithstanding that such Works are or may become annexed or affixed to the Strip and shall at anytime and from time to time be removable in whole or in part by the Transferee.

(c) No other easement or permission will be transferred or granted and no encumbrances will be created over or in respect to the Strip, prior to the registration of a Transfer of this grant of Rights.

(d) The Transferor will execute such further assurances of the Rights in respect of this grant of easement as may be requisite.

(e) The Rights hereby granted:

(i) shall be of the same force and effect to all intents and purposes as a covenant running with the Strip.

(ii) is declared hereby to be appurtenant to and for the benefit of the Works and undertaking of the Transferee described in paragraph 1(a).

3. The Transferor agrees that the Transferee may, at the Transferee's sole discretion, obtain at the Transferee's sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their

respective rights, title and interests to the Transfer of Easement herein so as to place such Rights and easement in first priority on title to the Lands.

4. There are no representations, covenants, agreements, warranties and conditions in any way relating to the subject matter of this grant of Rights whether expressed or implied collateral or otherwise except those set forth herein.

5. No waiver of a breach or any of the covenants of this grant of Rights shall be construed to be a waiver of any succeeding breach of the same or any other covenant.

6. The burden and benefit of this transfer of Rights shall run with the Strip and the Works and undertaking of the Transferee and shall extend to, be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

SCHEDULE “C”
CALCULATION SHEET

SCHEDULE "D"
ACKNOWLEDGEMENT AND DIRECTION

TO:	Hydro One Networks Inc. ("**Hydro One**") and its solicitors, Barriston LLP
AND TO:	Any and all designees of the above
RE:	Agreement to Purchase a Limited Interest – Easement dated ________________, 20____, (the **"Purchase Agreement"**) and the Transfer and Grant of Easement in Gross in substantially the form attached as Schedule "B" to the Purchase Agreement (the **"Easement Agreement"**)

This will confirm that:

- Hydro One and the Owner have reviewed the information set out in the Purchase Agreement and the draft document(s) attached to the Purchase Agreement, and that this information is accurate;
- You are authorized and directed to sign and register electronically on behalf of the undersigned the Purchase Agreement and the Easement Agreement as well as any other document(s) required to complete the transaction described above;
- You are authorized to amend the Purchase Agreement and the Easement Agreement as may be required to effect registration of such document including the insertion of a registerable legal description to describe the lands subject to the easement being granted pursuant to the Easement Agreement in the event one is not available at the time of execution of the Purchase Agreement; provided such amendments are non-material to the terms of the Purchase Agreement and the Easement Agreement and do not expand the description of the Easement Lands as described and/or illustrated in the Purchase Agreement in any material manner;
- The effect of the electronic documents described in this Acknowledgement and Direction has been fully explained to the Owner and Hydro One, and the Owner and Hydro One understand that each are parties to and bound by the terms and provisions of these electronic document(s) to the same extent as if each had signed these documents;
- You are directed to insert the names set forth in the signatory section of the Purchase Agreement as persons authorized (or other authorized signing officers of Hydro One) to act on behalf of Hydro One and the Owner, as applicable;
- The Owner acknowledges that Barriston LLP has not met with them nor been engaged by them, is not entering into a solicitor-client relationship with them and is not representing them solely or jointly with Hydro One for the purposes of the preparation, negotiation, completion or registration of the Purchase Agreement or the Easement Agreement. Barriston LLP will act in a limited capacity as agent for the undersigned for the purposes of registering the Purchase Agreement and the Easement Agreement; and
- Hydro One and the Owner are in fact the parties named in the electronic documents described in this Acknowledgement and Direction and each has not misrepresented the identity of same to you.

Dated ________________, 20__.

WITNESS:	**OWNER:**
______________________	______________________ l/s
Name:	Name:
Address:	
______________________	______________________ l/s
Name:	Name:
Address:	
______________________	______________________ l/s
Name:	Name:
Address:	

WITNESS:

The spouse of the Owner hereby consents to this Agreement

SPOUSE OF OWNER:

l/s

Name:

Name:

Address:

Per:

Name:

Title:

We/I have authority to bind the Corporation

OEB STAFF INTERROGATORY - 26

Reference:

EB-2025-0290, Scope of Proceeding, Decision on Issues List and Procedural Order No. 2, issued March 5, 2026

Preamble:

The Reference includes the OEB's Standard Conditions of Approval for Electricity Transmission Leave to Construct Applications.

Interrogatory:

a) Please comment on the above standard conditions in relation to this application. If Hydro One does not agree with any of the standard conditions of approval, please identify the specific conditions that Hydro One disagrees with, explain why, and provide proposed change

Response:

a) As detailed in Exhibit B, Tab 1, Schedule 1 of the Application, Hydro One consents to the conditions outlined in the OEB's standard conditions of approval for electricity transmission leave to construct applications for this Project.

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OEB STAFF INTERROGATORY - 27

Reference:

1. OEB CEO Policy 2026-01
2. *Energy for Generations, Ontario's Integrated Plan to Power the Strongest Economy in the G7 (June 2025)* (IEP)

Preamble:

As stated in Reference 1, OEB shall identify the portions of the IEP that are relevant to the matters in issue in the proceeding.

Interrogatory:

a) Please discuss if there are portions of the IEP that Hydro One considers relevant to this application.

Response:

a) The Project aligns with the aims of Ontario's IEP. As noted in Exhibit B, Tab 4, Schedule 1, the Project is a development project and therefore aligns with the Minister's message in the IEP that we must modernize the grid to meet the needs of tomorrow: "[A]s demand grows across the province, driven by population growth, electrification and new industrial projects, Ontario must act now to support the building and upgrading of the lines that will power our future and unleash our economy." [1] The IEP focusses in particular on growth in Eastern Ontario which is experiencing continued demand growth driven by population increases, new residential development, and expanded electrification and that action will be taken to ensure this growth is not constrained by transmission capacity.[2]

   The IEP also addresses how Ontario will be enabling growth through faster, streamlined connections. Specifically, the IEP details that:

   > *"A modern electricity grid must not only be reliable and efficient – it must also be responsive to growth. As Ontario continues to build homes, expand industrial capacity, and attract investment, customers need timely and affordable connections to the electricity system. The existing connection frameworks have not kept pace with the changes in the sector. Cost structures, limited planning coordination, and slow approval*

[1] Energy for Generations, Ontario's Integrated Plan to Power the Strongest Economy in the G7 (June 2025) – p. 68
[2] Energy for Generations, Ontario's Integrated Plan to Power the Strongest Economy in the G7 (June 2025) – p. 72

> *processes have created barriers for housing developments and job-creating projects*

The IEP also addresses how transmission infrastructure acts as a catalyst for attracting economic growth to the province as it relates to connection cost responsibility. Specifically, the IEP details:

> *The province remains committed to the 'Beneficiary Pays' principle that currently underpins the connection cost responsibility framework.* ***However, the application of this principle should not unduly burden first movers and discourage prudent, proactive investment in electricity infrastructure to meet broader provincial policy goals such as the construction of new homes, businesses and other priorities.*** *LDCs, transmitters and their shareholders should also be kept whole, and the potential for wasted costs or under-build must be minimized to protect Ontario ratepayers.*[3] *(emphasis added)*

As described in Exhibit I, Tab 1, Schedule 18, Hydro One is presenting an allocation consistent with the Transmission System Code, while considering the application of the 'Beneficiary Pays' principle so to not unduly burden customers to the province that will invest in broader provincial policy goals and priorities, as described in the IEP.

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[3] Energy for Generations, Ontario's Integrated Plan to Power the Strongest Economy in the G7 (June 2025) – p. 86

FUTECAN CANADA INC. INTERROGATORY - 01

Interrogatory:

Please identify any changes with respect to Hydro One's preferred routing alignment vis-a-vis the Segment[1] specifically related to the Futecan Property[2] since Hydro One submitted their application for Leave to Construct to the OEB, and in particular if Hydro One has reconsidered the preferred alternative, any alternative route alignment affecting the Property, or identified any new information that would materially affect the evaluation of such alternatives.

Response:

Though the Class EA process establishes the general preferred route of the Project, if feasible, it is not atypical for Hydro One to continue to make micro-route refinements to the preferred route as it engages in more in-depth discussions with directly affected land owners prior to construction commencement. This is what has occurred in this instance with the Futecan Property. Hydro One has carefully considered Futecan's feedback, based on the routing workshop discussions and subsequent technical review. As a result, through this interrogatory response, Hydro One is updating the route of the Project to reflect that the preferred route refined to route along the westerly perimeter of the Futecan Property. The route refinement reflects preferences and impact mitigation concerns that were raised by the landowner. Both parties have agreed to proceed with formalizing route refinements. The following Schedules in the Application are updated to reflect this change:

- Exhibit E, Tab 1, Schedule 1, Attachment 1

Notwithstanding any unforeseen technical, environmental, or regulatory considerations, Hydro One finds the refined route at the Futecan Property feasible and will continue to pursue it as the preferred alignment at the Futecan Property and adjacent properties along the proposed alignment.

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[1] "Segment" means the portion of the proposed Welland–Thorold Transmission Project located on, adjacent to, or within 50 metres of the Futecan Property.
[2] "Futecan Property" means the lands municipally known as located at 9941 Lundy's Lane where the Lundy Manor Wine Cellars are located.

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FUTECAN CANADA INC. INTERROGATORY - 02

Interrogatory:

Please indicate if Hydro One will be pursuing the "Technical Option" routing alternative[1] as their new preferred routing alternative, and how this will be operationalized through the current Leave to Construct application.

a) Please provide further information related to the "Technical Option" including the specific location, the width of the right-of way over or along the Futecan Property, the proposed location of the towers in relation to the Segment and the Futecan Property.

b) Please provide a description of any considerations, factors or criteria that could alter Hydro One's decision with respect to route alignment and path for this Segment.

Response:

Please refer to Exhibit I, Tab 2, Schedule 1.

[1] "Futecan Property" means the lands municipally known as located at 9941 Lundy's Lane where the Lundy Manor Wine Cellars are located.

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FUTECAN CANADA INC. INTERROGATORY - 03

Interrogatory:

Please provide further information related to the "Technical Option" shown in purple on the Futecan Property at page 148 of the Application Materials and specifically provide the following information in relation to the "Technical Option" as compared to Hydro One's preferred routing alignment, related to the following criteria:

i) cost differences, including construction costs and anticipated costs for expropriation or land acquisition,
ii) timing differences for the construction of the project (i.e. if expropriation is necessary for Hydro One's preferred routing alignment but not necessary for the Technical Option);
iii) technical feasibility;
iv) safety and reliability;
v) constructability;
vi) environmental effects;
vii) land use compatibility;
viii) on-going ease of repair and maintenance including associated costs; and
ix) impacts on the Futecan Property as compared to the preferred alignment for which Hydro One is seeking OEB approval.

For clarity, the "preferred alternative" selected as per the Class EA, runs through a significant portion of the Futecan Property, where it veers away from the road allowance and transects the Futecan Property at a 45 degree angle, whereas the "Technical Option" runs along the road allowance at the edge of the Futecan Property.

Response:

i) Both routes have a similar number of towers and length and therefore have similar anticipated cost. There is no anticipated cost difference for expropriation for either option. Land acquisitions from either option are marginally different and Hydro One is only pursuing one third-party appraisal to ascertain the cost associated with the acquisition of land rights associated with the technical solution that Futecan indicated to Hydro One was their preferred solution.

ii) No timing difference for expropriation given the Procedural Order #2, expropriation will be submitted in the same time on either option.

iii) Both routes are technically feasible.

iv) Both routes are similar in terms of safety and reliability.

v) Both routes are similar in terms of constructability.

vi) Environmental impacts for routing assessment are outlined within the ESR. Routing criteria, environmental studies and further detailed field work are being progressed within the subject lands. Realigning the corridor to parallel Thorold Townline Road will reduce the overall impact to lands due to lower total corridor length and corridor overlap with pre-existing disturbed areas requiring less total vegetation clearing.

vii) The assessment of land-use compatibility reflects the suitability of the property's current use. Any potential additional uses would require further review and will be evaluated by an independent third-party appraiser.

viii) Both routes are similar in terms of repair and maintenance.

ix) The technical option was developed collaboratively with Futecan and is intended to address their concerns regarding land impact, as it keeps the proposed transmission corridor's confined to the property's perimeter along Thorold Townline Road.