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File No. 14898.13

May 16, 2024

BY EMAIL & RESS

Ms. Nancy Marconi
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P1E4

Dear Ms. Marconi:

Re: PUC (Transmission) LP ("PUCTx") and Hydro One Sault Ste. Marie ("HOSSM") Application for Leave to Construct and Related Matters ("Application")
Ontario Energy Board ("OEB") File No. EB-2023-0360
Interrogatory Responses

On March 28, 2024, the OEB issued Procedural Order No. 1 setting out a process for interrogatories on the Application. On May 2, 2024, OEB Staff and Essar Power Canada Ltd. filed written interrogatories to PUCTx and HOSSM. Enclosed are PUCTx's and HOSSM's responses to those interrogatories.

PUCTx is hereby requesting confidential treatment of the attachments to the response to interrogatory Staff-6(b) and certain information contained in Staff-6(d), pursuant to sections 10.01 and 10.02 of the OEB's *Rules of Practice and Procedure* (revised July 13, 2023) and sections 5.1.1 and 5.1.2 of the OEB's *Practice Direction on Confidential Filings* (revised December 17, 2021) ("**Practice Direction**").

Location	Reason for Confidentiality
Staff-6(b): Appendix A and Appendix B	Both Appendix A and B are presumptively confidential as they include unit pricing and billing rates of third party vendors. The data provided in these appendices includes detailed quotes of unit prices and billing rates of on a component by component and job basis and would be significantly prejudicial to each of the third parties' competitive position if disclosed. This information would be valuable to the third parties' competitors and would represent a significant loss. Disclosure may also prejudice future competitive procurement processes on the Project and result in less competition, negatively affecting ratepayers.

Staff-6(d)	The range PUCTx expects for the Construction Contract, as a function of total contract price, has been redacted as presumptively confidential. This range is generated based on unit pricing and billing rates of third parties. The Construction Contract has not yet been put out for tender and disclosing this information could be expected to materially influence future competitive procurement processes as bidders would know what PUCTx expects the value of the Construction Contract to be. This will be prejudicial for both ratepayers and PUCTx as market forces would no longer be determining the construction costs of the Project. Furthermore, this information could also qualify for confidentiality under Appendix A of the Practice Direction as disclosure would reasonably be expected to interfere significantly with negotiations PUCTx would carry out in the future for Project equipment, material, and services.

Please contact the undersigned with any questions.

Yours truly,

BORDEN LADNER GERVAIS LLP

Colm Boyle

Colm Boyle

CB/JV

ONTARIO ENERGY BOARD

PUC (TRANSMISSION) LP

HYDRO ONE SAULT STE. MARIE

INTERROGATORY RESPONSES

Filed: May 16, 2024

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INTERROGATORY RESPONSES TO STAFF

Staff-1:

Reference: Exhibit B, Tab 1, Schedule 1, page 4
Exhibit B, Tab 2, Schedule 1, page 3

Preamble:

In addition to meeting the needs of Algoma Steel Inc. (Algoma Steel), the application states the following: “The Project will also support PUC Distribution’s infrastructure renewal, connect new generators, and supply additional load customers that are currently being planned for the area.”

The second reference states: “Connection to PUC Transmission’s new station at 230 kV will allow for PUC Distribution to eliminate one of its two 115 kV stations, and to reconstruct the other.”

Question(s):

a) Please clarify how many “new generators” have indicated to PUC Transmission that they plan to connect and the related supply capacity (MW).

b) Please clarify how many new “additional load customers” (i.e., beyond Algoma Steel) have indicated to PUC Transmission that they plan to connect and the amount of capacity (MW) they will require to meet their planned energy needs.

c) Please comment on the cost savings that may be achieved by the elimination of one of PUC Distribution’s noted 115 kV stations.

PUC Transmission Response(s):

a) PUC Transmission is aware of two potential new generators that plan to connect with a combined capacity in the order of 425 MW.

b) PUC Transmission has been consulting with the Economic Development team and city staff at the City of Sault Ste. Marie to better understand future anticipated electricity load growth from future commercial and residential development. PUC Transmission is aware of three potential new load customers that would require connection at the Tagona West TS. The first customer has indicated they would connect at 100MW and scale up as demand increases, the second customer has indicated they would connect at 300MW and scale up as demand increases. The third customer has indicated a demand of 100 MW.

c) PUC Distribution recently completed a feasibility study for multiple replacement/reconstruction options related to its two 115 kV transformer stations, St. Mary’s TS and Tarentorus TS.

PUC Distribution has estimated an initial capital cost savings of approximately $21.3M for station construction by rebuilding St. Mary's TS, retiring and demolishing Tarentorus TS, and adding capacity to the 34.5kV bus at Tagona West TS.

PUC has estimated a maintenance cost savings of approximately $215k every four years by retiring Tarentorus TS.

Furthermore, assuming that transferring the 115 kV load of Tarentorus TS to the 230 kV system at Tagona West TS would eliminate the need for a third autotransformer at Third Line TS to address the Sault No. 3 Need, as discussed in Exhibit H, there is potential for an additional $20M capital cost savings.

<u>Staff-2:</u>

Reference: Exhibit B, Tab 2, Schedule 1, page 1

Preamble:

As part of the application, PUC Transmission notes that "Each 230 kV circuit will utilize a single 954 MCM ACSR conductor per phase at this time."

Question(s):

a) Please provide an analysis of conductor size alternatives in accordance with section 4.3.2.5 of OEB Filling Requirements for Electricity Transmission Leave to Construct and Related Matters (Chapter 4 Filing Requirements).[1] If PUC Transmission is of the view that this analysis is not needed for the decision on conductor size, please explain why.

PUC Transmission Response(s):

a) Two conductor sizes were considered: 795 MCM ACSR and 954 MCM ACSR. The overall circuit loading capacity is 250 MVA for the 759 MCM conductor versus 400 MVA for the 954 MCM conductor. The higher capacity is required to satisfy the total expected load of 280 MVA while providing the redundancy required to ensure reliable service. Based on the above considerations, the 954 MCM conductor has been selected for this project.

[1] Filling Requirements for Electricity Transmission Applications Chapter 4 Leave to Construct and Related Matters under Part VI of the Ontario Energy Board Act, dated March 16, 2023

<u>Staff-3:</u>

Reference: Exhibit B, Tab 3, Schedule 1, pages 2-4

Preamble:

PUC Transmission states in the application that construction of Algoma Steel’s new electric arc furnaces (EAFs) is currently well under way, and the anticipated completion of construction is scheduled for mid-2024. The application also states that the planned development of Algoma Steel’s EAF project, with respect to energy use, encompasses three distinct stages. The description of the three stages is provided in the application.

Question(s):

a) Please indicate which stage (or sub-stage) is Algoma Steel’s EAF project currently at.

b) What is Algoma Steel’s current project schedule with respect to the three stages?

c) Please illustrate the relationship between the proposed project schedule for PUC Tx Project (and HOSSM Station Project) and the schedule and progress for the Algoma Steel’s EAF project.

PUC Transmission Response(s):

a) Algoma Steel’s EAF project has not reached Stage 1 yet as the first arc furnace is currently under construction. The anticipated in-service date of the first furnace is Q1 2025 followed by the second furnace in Q2 2025.

b) Algoma’s construction schedule does not coordinate with the three energy use stages described in the application. The timing of each energy use stage is summarized in the following table:

Energy Use Stage	Operating Mode	Timing Dependency	Projected In-Service Date
Stage 1	Both arc furnaces would be supplied through the 115 kV Clergue TS connection with only one furnace arcing at full power at any time. In this scenario, Algoma’s Lake Superior Power (LSP) natural gas generating station would be operating full-time to	In-service is dependent on completion by Algoma of the project construction and registration of the new 115 kV EAF Station with the IESO.	First EAF – Q1 2025 Second EAF – Q2 2025

	supply the required additional electricity required by each arc furnace.		
Stage 2A	Only one furnace arcing at full power at any time and LSP not generating electricity.	In-service is dependent on the PUC Transmission project and HOSSM project completion, registration of the facilities with the IESO.	July 2027
Stage 2B	Both furnaces arcing simultaneous with the LSP facility in operation at full output.	In-service dependency is the same as Stage 2A. Algoma would choose to operate either in Stage 2A or Stage 2B mode.	July 2027 (if Algoma decides to utilize this operating mode)
Stage 3	Both furnaces arcing simultaneous without the LSP facility in operation.	In-service is dependent on completion of the bulk system upgrades to the provincial transmission grid upstream of the Third Line Station.	2029

c) PUC Transmission’s overall project schedule is dependent upon the timing of the leave to construct approval, long lead equipment delivery dates, and coordination with HOSSM’s modifications at the Third Line TS. Algoma’s Stage 1 energy use start date is not tied to and is independent of the PUC Tx Project, as noted in part (a) above. PUC Transmission must complete the PUC Tx Project and HOSSM must complete the modifications at the Third Line TS in order for Algoma to move to Stage 2 and subsequent energy use states.

<u>Staff-4:</u>

Reference: Exhibit B, Tab 3, Schedule 1, page 1

Preamble:

PUC Transmission states that its proposed facilities will provide the increased transmission supply capacity and improve system reliability required to meet the increasing short-term and long-term power demands of the significant load growth forecasted for development within Sault Ste. Marie.

Question(s):

a) Please provide five years of historical demand information for Sault Ste. Marie.

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

HOSSM Response(s):

a) Table 1 below contains the last 3 years coincident peak of all stations within the East Lake Superior (ELS) region. City of Sault Ste. Marie load was then isolated by subtracting load at: Andrews TS, Batchawana TS, Chapleau DS and TS, DA Watson TS, Echo River TS, Gold Mine CTS, Goulais Bay TS, Mackay TS and Circuit No.4 load.

	Peak Demand by year (MW)		
Region/City	***2021***	***2022***	***2023***
ELS	311	316	325
Sault Ste. Marie	259	252	264

Sault Ste. Marie is currently served by Great Lakes Power (GLP). Although GLP was acquired by Hydro One by forming a subsidiary, Hydro One Sault Ste. Marie (HOSSM), it has not been fully integrated with Hydro One system. We currently have limited information on delivery points related to Sault Ste. Marie as presented in Table 1. We will try, on best effort basis, to extend that information to 5 years. However, such task could not to be completed within the time limit of this response.

PUC Transmission Response(s):

b) PUC Transmission's 5-year demand forecast for the PUC Tx Project is included in the table below.

Load/Generator Forecast: Tagona West TS	**07/2027**	**07/2028**	**07/2029**	**07/2030**	**07/2031**
Algoma Steel EAFs	140	140	140	280	280
PUC Distribution		85	85	85	85
Load Customer A	100	100	100	100	100
Load Customer B	300	300	300	300	300
Load Customer C	100	100	100	100	100
Station Total - Load Customers (MW withdrawn)	640	725	725	865	865
Generator A		125	125	125	125
Generator B		300	300	300	300
Station Total - Generators (MW injected)	0	425	425	425	425
Assumptions:					
Algoma Steel forecast from SIA reports					
Bulk System Upgrades completed late 2029					
PUC-D transformer station rebuilds begin in 2028 and continue until 2038					

Staff-5:

Reference: Exhibit B, Tab 3, Schedule 1
Exhibit H, Tab 1, Schedule 1
IESO's Annual Planning Outlook (March 2024), page 44
Chapter 4 Filing Requirements, section 4.3.2.3

Preamble:

The Chapter 4 Filling Requirements requires the applicants to provide evidence to the OEB that identifies the recommended and planned transmission and non-wire projects in any regional plans and/or IESO bulk plans that have linkages and/or interdependencies to the applied-for transmission project. This evidence is to be in the form of a document prepared by the IESO.

IESO's latest Annual Planning Outlook lists a number of planned bulk transmission projects specific to the Sault Ste. Marie region (page 44- Northeastern Ontario Bulk Transmission System Reinforcements).

Question(s):

a) Please discuss the relationship between the proposed transmission Project and any reginal plans and/or IESO bulk plans and provide the evidence noted in the Preamble. Specifically, please comment on the relationship between the proposed transmission Project and the planned transmission initiatives noted in IESO's Annual Planning Outlook for the Sault Ste. Marie region.

b) In Exhibit H, Tab 1, Schedule 1, PUC Transmission notes the following:

> It is noted that moving the Tarentours TS load to the Tagona West TS would avoid the need to add a third autotransformer at the Third Line TS, which would address the Sault No. 3 Need. The ELS Working Group is working towards issuing an addendum to the 2021 East Lake Superior Integrated Regional Resource Plan (IRRP) which considers PUC Distribution's planned station replacements.

What is the status of the above noted addendum to the 2021 East Lake Superior IRRP? Please provide this addendum if it is available.

c) Please discuss whether or not the need of the proposed Project (PUC Tx Project and HOSSM Station Project) relates to meeting reliability standards or other obligations specified by any regulatory organizations. If yes, please provide detail and describe how the Project will help address the standards or obligations.

PUC Transmission Response(s):

a) On October 23, 2023, the Ontario government issued an Order-in-Council declaring three transmission line projects as priorities in northeast and eastern Ontario. The government also directed the OEB to amend HONI's transmission licence to designate it as the transmitter responsible for the development of the three lines. The bulk planning group also published its report in October 2022 titled "Need for Northeast Bulk System Reinforcement" in respect of northeast Ontario. It is these regional initiatives, combined with load demand around Sault Ste. Marie, that the PUC Transmission Project facilitates and is integral to regional plans and/or IESO bulk plans.

b) A 2024 IRRP is currently underway for the East Lake Superior (ELS) region and through discussions with HONI in 2023 it was determined that an addendum to the 2021 ELS IRRP was not required because of the 2024 IRRP process. The current 2024 ELS IRRP schedule plans for the final report to be completed in October 2024. The assessment of the Third Auto-Transformer requirement will be completed through the 2024 IRRP and a Local Planning Report developed jointly with PUC and HONI.

c) The current transmission facilities downstream of the Third Line TS are inadequate to supply Algoma Steel's new EAF facilities. The PUC Transmission Project will provide the new transmission facilities that are required to supply Algoma Steel's new EAF facilities. The PUC Transmission facilities will provide the level of reliability consistent with the Transmission System Code provisions.

Staff-6:

Reference: Exhibit B, Tab 6, Schedule 1, pages 1-3

Preamble:

The application states: "The Project costs are formulated by combining actual costs incurred to date, and an estimate of remaining development and construction costs to the projected in-service date. Forecasts are based on vendor quotes and estimated construction costs for similar work derived from past experience of the consultants."

The above reference states that the total estimated cost of work for the entire Project is $231.98 million.

Further, it is also stated that the cost estimates are based on:

- Pre-purchase of long lead equipment under competitive bidding process; and
- Allowance for a competitive-bid selection of a Construction Contract to carry out procurement of the balance of equipment and materials, and to carry out the construction of line and station in accordance with pre-defined detailed engineering.

Question(s):

a) Please provide a breakdown of the actual costs incurred to date.

b) Please provide all the vendor quotes received as part of the cost estimation process.

c) Please provide additional details on the competitive bidding process for the long lead equipment. How many vendors participated in the bidding process? What is the value of the contract related to the long lead equipment?

d) What is the expected magnitude of the Construction Contract as a percentage of the total Project cost?

PUC Transmission Response(s):

a) The table below summarizes actual costs incurred to end of April 2024.

Cost Category	Total Actual to end of April 2024
Labour	$155,851.00
Materials	nil
Real Estate, Land Rights	$64,905.00

Overheads	$4,993,125.00
Other: **Permits and Approvals**	$211,822.00
	$5,425,703.00

b) Please see confidential Appendix A attached herein that includes various budgetary quotes provided by vendors and cost estimates developed by the consultants related to the station procurement and construction.

Please see confidential Appendix B attached herein that includes various budgetary quotes provided by vendors and cost estimates developed by the consultants related to the line procurement and construction.

c) At this time, no long lead equipment has been purchased. Tenders were issued for autotransformers, breakers and switches, and bids have been received and evaluated. However, PUC Transmission has not entered into a purchase order contract for long lead equipment as of this filing.

The table below summarizes the long lead equipment bids.

Long Lead Equipment Type	Number of Vendors Issued an RFQ	Number of Vendors that submitted bids	Total Value ($M)
Autotransformers	4	2	16.54
Circuit Breakers	4	2	
Capacitive VTs	4	3	
Disconnect Switches	5	5	

d) PUC expects the Construction Contract to be approximately [redacted]% of the total project cost.

<u>Staff-7:</u>

Reference: Exhibit B, Tab 6, Schedule 1, Table 3, page10

Preamble:

Costs associated with network assets are typically socialized (i.e., recovered from all Ontario ratepayers). Table 3 in the application identifies two types of network assets where the costs have been allocated to Algoma Steel:

(1) Two 115 kV breakers that connect the 115 kV circuits that will supply power to Algoma Steel's EAF facility ($10.3M); and

(2) One reactive power device required to protect other customers connected to the IESO grid from being negatively impacted by excessive voltage variations from the operations of Algoma's new EAF facility ($45M).

PUC Transmission notes the treatment associated with those network assets is consistent with the guidance provided in the OEB Bulletin (September 2022) that clarifies the circumstances under which transmitters should allocate costs associated with a network facility upgrade to a specific generator or load customer; i.e., where they form the minimum connection requirements.

That OEB Bulletin provided a list of the common examples where network assets form the minimum connection requirements. The application appears to indicate that PUC Transmission focused on those examples. The Bulletin also notes:

"For other potential scenarios that may arise as the transmission system evolves, OEB staff is of the view that transmitters should be guided by the following: the connecting customer should be required to pay for the investment in the network facility where they are the sole or primary beneficiary and/or the investment is required to mitigate other customers being negatively impacted (e.g., reduced reliability) as a result of the connecting customer's new or modified connection to the transmission system."

Question(s):

a) Please identify if any other network assets related to the project were considered as potential assets that form the minimum connection requirements discussed in the OEB Bulletin, but PUC Transmission ultimately decided not to allocate the cost to Algoma Steel.

b) If other assets were considered, please identify those assets and the related cost. Please also explain why PUC Transmission decided not to allocate any costs to Algoma Steel in relation to those assets.

c) If no other network assets were considered, please confirm Algoma Steel will not be the sole or primary beneficiary associated with any other network asset investment(s).

PUC Transmission Response(s):

a) No other network assets were identified as forming part of the minimum connection requirements to connect Algoma's two 115 kV circuits.

b) See response to part (a) above.

c) To the best of PUC Transmission's knowledge, Algoma Steel will not be the sole beneficiary associated with the Project. Please see the response to OEB Staff 1 above.

Staff-8:

Reference: Exhibit B, Tab 6, Schedule 1, Table 1, page 1
Exhibit B, Tab 6, Schedule 1, Table 3, page 10

Preamble:

Table 1 of the application sets out the "Estimated Cost of Work" and states "PUC Transmission Only" in brackets in the title of the table. Table 3 in the same section of the application identifies the "Minimum Connection Facilities Required to Connect Algoma Steel".

Question(s):

a) Please clarify whether the $55.4M allocated to Algoma Steel (in Table 3) based on the guidance in the OEB staff Bulletin is included in the total estimated cost of work of $188.87M (in Table 1).

PUC Transmission Response(s):

a) Yes, the $55.4M is included in the total cost of $188.87M

Staff-9:

Reference: Exhibit B, Tab 7, Schedule 1

Preamble:

In Exhibit B, Tab 7, Schedule 1, PUC Transmission identified four key risks and associated potential impact on the proposed project.

Question(s):

a) Please discuss the options that PUC Transmission employed or plans to employ to mitigate the key risks.

PUC Transmission Response(s):

a) The identified key project risks are not unique to the PUC Transmission project and encountered by nearly every transmission project proponent. Given that the bulk of PUC Transmission project costs will be incurred after leave to construct is approved, PUC Transmission is still evaluating the feasibility of the following options to mitigate key risks:

Cost estimating accuracy / pricing variations: This risk can be mitigated by entering into firm quotes or fixed price contracts with service suppliers and vendors, however it is not clear at this time whether potential vendors would be receptive to such an arrangement. The difficulty in constraining cost estimates is that they are typically valid for a limited period of time and many market changes can occur prior to leave to construct being issued by the OEB.

Approvals and permits: There are no alternatives to obtaining approvals or permits. PUC Transmission intends to pursue approvals and permits diligently with the relevant authorities. It is noted that the Environmental Assessment was concluded in October 2022 to mitigate the potential for delays related to environmental approvals. Also, it is noted that preliminary approval has been received from the Sault Ste. Marie Region Conservation Authority in relation to the clearing of trees along the existing easements and placement of poles on Conservation lands that are the subject of proposed easements.

Material and equipment delivery timelines: Delivery timelines are a key metric in the evaluation of vendors and bids. Delivery of equipment and material needs to be timely to facilitate construction activities. PUC Transmission intends to mitigate this risk by attempting to negotiate firm delivery dates with potential penalties for delay. However it is not clear at this time whether potential vendors would be receptive to such an arrangement.

As noted in Exhibit B, Tab 7, Schedule 1, Project Risks, a contingency allowance is including the overall project cost estimate to mitigate the identified key project risks. The magnitude of the contingency allowance is derived from consideration of the Class 3 nature of the project estimate and is approx. 10% of the total PUC Transmission project costs excluding capitalized interest.

<u>Staff-10:</u>

Reference: Exhibit B, Tab 8, Schedule 1
Exhibit B, Tab 8, Schedule 1 Table 1, Table 2, Table 3, Table 4

Preamble:

In Exhibit B Tab 8 Schedule 1, it's stated that PUC Transmission has applied the annual Input Price Index (IPI) inflation adjustment factors listed in the manner set out in Table 2 (IPI factors in accordance with the year of the underlying data that the indices were calculated from) to account for the two-year lag in IPI rates when determining the inflation adjustments applied to the comparative projects that are listed in Table 3 and Table 4.

Question(s):

a) Please provide the detailed calculations for the escalated project costs of the three comparable projects as presented in Table 3 in Exhibit B, Tab 8, Schedule 1 (in amount of $10.71M, $18.89M and $10.90M).

b) Please provide the detailed calculations for the escalated project costs of the three comparable projects as presented in Table 4 in Exhibit B, Tab 8, Schedule 1 (in amount of $8,922k, $12,070k, $12,522k and $12,347k).

c) For the three comparable line construction projects, please update the "Escalation Adjustment", "Escalated Project Costs" and "Cost per km" rows in Table 3 in Exhibit B, Tab 8, Schedule 1 with the IPI inflation factors listed in the manner set out in Table 1 (OEB IPI inflation factors without adjustment for two-year lag). Please provide the calculations.

d) For the four comparable station construction projects, please update the "Escalation Adjustment", "Escalated Total Comparable Costs" and "Cost per kVA" rows of Table 4 in Exhibit B, Tab 8, Schedule 1 with the IPI inflation factors listed in the manner set out in Table 1 (OEB IPI inflation factors without adjustment for two-year lag). Please provide the calculations.

e) Please indicate whether the methodology of adjusting the OEB IPI inflation factors for two-year lag in calculating the escalated costs of comparable projects has been used in any previous OEB-approved leave to construct applications. If yes, please provide the related reference. If no, please explain why this method is reasonable in the cost of comparable projects analysis in this application.

PUC Transmission Response(s):

a) The following table summarizes the detailed calculation for the escalated costs of the three comparable line projects presented in Table 3 in Exhibit B, Tab 8, Schedule 1.

Line Projects ($M)

without 2 yr lag underlying data	OEB IPI Inflation Factor	BATU EB-2018-0117 Opening + Escalated Amount	BATU EB-2018-0117 Annual Escalation	WATR EB-2018-0117 Opening + Escalated Amount	WATR EB-2018-0117 Annual Escalation	GATR EB-2018-0117 Opening + Escalated Amount	GATR EB-2018-0117 Annual Escalation
2011	2.20%			$30.00	$0.45		
2012	2.0%			$30.45	$0.49		
2013	1.60%			$30.94	$0.65		
2014	2.10%			$31.59	$0.60		
2015	1.90%			$32.19	$0.39	$21.70	$0.02
2016	1.20%			$32.57	$0.49	$21.72	$0.33
2017	1.50%			$33.06	$0.66	$22.05	$0.44
2018	2.00%			$33.72	$0.67	$22.49	$0.45
2019	2.00%			$34.40	$0.86	$22.94	$0.57
2020	2.50%			$35.26	$1.34	$23.51	$0.89
2021	3.80%	$35.50	$0.96	$36.60	$1.98	$24.41	$1.32
2022	5.40%	$36.46	$1.97	$38.57	$2.08	$25.72	$1.39
2023	5.40%	$38.43	$2.08	$40.66	$2.20	$27.11	$1.46
2024	5.40%	$40.50	$2.19	$42.85	$2.31	$28.58	$1.54
2025	5.40%	$42.69	$2.31	$45.17	$2.44	$30.12	$1.63
2026	5.40%	$44.99	$1.21	$47.60	$1.29	$31.75	$0.86
Opening 2027	5.40%						
Closing 2027		$46.21	$10.71	$48.89	$18.89	$32.60	$10.90
Average	**3.25%**	9	km	13.6	km	5	km
		$5.13	$M/km	$3.59	$M/km	$6.52	$M/km

b) The following table summarizes the detailed calculation for the escalated costs of the four comparable station projects presented in Table 4 in Exhibit B, Tab 8, Schedule 1.

Station Projects ($M)

without 2 yr lag underlying data	OEB Inflation Factor	Barrie TS EB-2018-0117 Opening + Escalated Amount	Barrie TS EB-2018-0117 Annual Escalation	St. Isidore TS EB-2022-0140 Opening + Escalated Amount	St. Isidore TS EB-2022-0140 Annual Escalation	Palmerston TS EB-2018-0117 Opening + Escalated Amount	Palmerston TS EB-2018-0117 Annual Escalation	Enfield TS EB-2018-0117 Opening + Escalated Amount	Enfield TS EB-2018-0117 Annual Escalation
2011	2.20%								
2012	2.0%								
2013	1.60%								
2014	2.10%								
2015	1.90%								
2016	1.20%								
2017	1.50%								
2018	2.00%								
2019	2.00%					$28.442	$0.379	$28.196	$0.329
2020	2.50%			$29.877	$0.373	$28.821	$0.721	$28.525	$0.713
2021	3.80%			$30.250	$1.150	$29.542	$1.123	$29.238	$1.111
2022	5.40%	$29.576	$0.799	$31.400	$1.696	$30.664	$1.656	$30.349	$1.639
2023	5.40%	$30.375	$1.640	$33.096	$1.787	$32.320	$1.745	$31.988	$1.727
2024	5.40%	$32.015	$1.729	$34.883	$1.884	$34.066	$1.840	$33.715	$1.821
2025	5.40%	$33.744	$1.822	$36.766	$1.985	$35.905	$1.939	$35.536	$1.919
2026	5.40%	$35.566	$1.921	$38.752	$2.093	$37.844	$2.044	$37.455	$2.023
Opening 2027	5.40%	$37.486	$1.012	$40.844	$1.103	$39.887	$1.077	$39.477	$1.066
Close 2027		$38.498	$8.922	$41.947	$12.070	$40.964	$12.522	$40.543	$12.347
Average	**3.25%**	250	MVA	166	MVA	166	MVA	250	MVA
		$150	$/kVA	$246	$/kVA	$240	$/kVA	$158	$/kVA

c) The following table summarizes the detailed calculation for the escalated costs of the three comparable line projects presented in Table 3 in Exhibit B, Tab 8, Schedule 1 utilizing the inflation adjustment factors set out in Table 1 of the same schedule.

Line Projects ($M)		BATU EB-2018-0117		WATR EB-2018-0117		GATR EB-2018-0117	
with 2 yr lag in underlying data	**OEB IPI Inflation Factor**	**Opening + Escalated Amount**	**Annual Escalation**	**Opening + Escalated Amount**	**Annual Escalation**	**Opening + Escalated Amount**	**Annual Escalation**
2011	1.30%						
2012	1.70%			$30.00	$0.38		
2013	2.20%			$30.38	$0.67		
2014	2.0%			$31.05	$0.62		
2015	1.60%			$31.67	$0.51		
2016	2.10%			$32.18	$0.68	$21.70	$0.04
2017	1.90%			$32.85	$0.62	$21.74	$0.41
2018	1.20%			$33.48	$0.40	$22.15	$0.27
2019	1.50%			$33.88	$0.51	$22.42	$0.34
2020	2.00%			$34.39	$0.69	$22.75	$0.46
2021	2.00%			$35.08	$0.70	$23.21	$0.46
2022	2.50%	$35.50	$0.44	$35.78	$0.89	$23.67	$0.59
2023	3.80%	$35.94	$1.37	$36.67	$1.39	$24.26	$0.92
2024	5.40%	$37.31	$2.01	$38.07	$2.06	$25.19	$1.36
2025	5.40%	$39.32	$2.12	$40.12	$2.17	$26.55	$1.43
2026	5.40%	$41.45	$2.24	$42.29	$2.28	$27.98	$1.51
Opening 2027	5.40%	$43.69	$1.18	$44.57	$1.20	$29.49	$0.80
Closing 2027		$44.87	$9.37	$45.78	$15.78	$30.29	$8.59
Average	**2.79%**	9	km	13.6	km	5	km
		$4.99	$M/km	$3.37	$M/km	$6.06	$M/km

d) The following table summarizes the detailed calculations for the escalated costs of the four comparable station projects presented in Table 4 in Exhibit B, Tab 8, Schedule 1 utilizing the inflation adjustment factors set out in Table 1 of the same schedule.

Station Projects ($M)		Barrie TS EB-2018-0117		St. Isidore TS EB-2022-0140		Palmerston TS EB-2018-0117		Enfield TS EB-2018-0117	
with 2 yr lag in underlying data	**OEB IPI Inflation Factor**	**Opening + Escalated Amount**	**Annual Escalation**	**Opening + Escalated Amount**	**Annual Escalation**	**Opening + Escalated Amount**	**Annual Escalation**	**Opening + Escalated Amount**	**Annual Escalation**
2011	1.30%								
2012	1.70%								
2013	2.20%								
2014	2.0%								
2015	1.60%								
2016	2.10%								
2017	1.90%								
2018	1.20%								
2019	1.50%					$28.442	$0.284	$28.196	$0.247
2020	2.00%			$29.877	$0.299	$28.726	$0.575	$28.443	$0.569
2021	2.00%			$30.176	$0.604	$29.301	$0.586	$29.012	$0.580
2022	2.50%	$29.576	$0.370	$30.779	$0.769	$29.887	$0.747	$29.592	$0.740
2023	3.80%	$29.946	$1.138	$31.549	$1.199	$30.634	$1.164	$30.332	$1.153
2024	5.40%	$31.084	$1.679	$32.748	$1.768	$31.798	$1.717	$31.484	$1.700
2025	5.40%	$32.762	$1.769	$34.516	$1.864	$33.515	$1.810	$33.184	$1.792
2026	5.40%	$34.531	$1.865	$36.380	$1.965	$35.325	$1.908	$34.976	$1.889
Opening 2027	5.40%	$36.396	$0.983	$38.344	$1.035	$37.233	$1.005	$36.865	$0.995
Closing 2027		$37.379	$7.803	$39.380	$9.503	$38.238	$9.796	$37.860	$9.664
Average	**2.79%**	250	MVA	166	MVA	166	MVA	250	MVA
		$146	$/kVA	$231	$/kVA	$224	$/kVA	$147	$/kVA

e) A similar method has been used in OEB-approved leave to construct applications EB-2023-0198 (see OEB Staff IRs 09, 12 and 13 filed on December 19, 2023) and EB-2023-0061 (see OEB Staff IR 04 filed on October 2, 2023). PUC Transmission is aware that HONI has also historically assumed an escalation adjustment of 2% per year when generating the costs of comparable projects. As shown in Table 1 of the Application at Exhibit B, Tab 8, Schedule 1, page 3, this assumption may have been reasonable between 2008 and 2022 when the OEB IPI Inflation Factor fluctuated between 1.3% and 2.5% and averaged 1.85% over this period. However, inflation significantly accelerated in the wake of COVID-19 hitting the highest ever IPI posted by the OEB at 5.4% in 2024, as discussed in Exhibit B, Tab 8 Schedule 1.

The OEB IPI Inflation Factor should be adjusted to account for the two-year lag to ensure that historical project costs are inflated at the correct percentage for the corresponding year. For example, the 2024 IPI is based on inflation calculations from 2022. Thus, it is most appropriate to apply the 2024 IPI to 2022 year for the purposes of escalating costs to ensure a fair comparison between the proposed project and comparable line and station construction projects, as reflected in Table 2 of the Application at Exhibit B, Tab 8, Schedule 1, page 4.

Staff-11:

Reference: Exhibit B, Tab 8, Schedule 1, page 7

Preamble:

On page 7 of Exhibit B Tab 8 Schedule 1, PUC Transmission states the following:

> The proposed Tagona West TS is similar to the cited comparable stations, with respect to number of transformers. However, the Tagona West TS will have a substantially higher maximum transformation capacity than any of the comparable station projects. With 2 autotransformers rated at 200 MVA each, the station will have a maximum total rating of 400 MVA. The comparatives are either 250 MVA or 166 MVA total station rating. Therefore, the appropriate cost comparison parameter should be the cost per MVA of station capacity, rather than the total station cost. In the interest of simplifying the presentation, cost per kVA is the preferred reference.

Question(s):

a) Can PUC Transmission find other comparable transformer station(s) with similar transformation capacity for the comparison? If yes, please add the similar transformer station(s) into the analysis and update Table 4. If PUC Transmission cannot find another comparable transformer station with similar transformation capacity, please explain why.

PUC Transmission Response(s):

a) PUC Transmission recently became aware of only one comparable station project with similar transformation capacity as the Tagona West TS. That station was part of application EB-2013-0053, Guelph Area Transmission Refurbishment ("GATR"), filed March 8, 2013, wherein the existing Cedar TS was upgraded with the addition of 2 – 250 MVA autotransformers with associated breakers.

However, a detailed description of the scope of work done at the Cedar TS is not available under that application because it was filed before this requirement existed in Chapter 4 of the Filing Requirements. Therefore, PUC Transmission is unable to update Table 4 due to the limitations of available information.

Based on the available information in the GATR Project application of 2013, the cost of the work at the Cedar TS was identified as $60M.

With adjustment for inflation, in accordance with the OEB IPI inflation factors identified in Table 2, Exhibit B, Tab 8, Schedule 1, the adjusted cost of the Cedar TS additions are $98.9M which results in a cost per kVA of $188.

The adjusted cost per kVA for the Cedar TS additions are in line with the Tagona West TS cost of $194 per kVA of transformation capacity.

Staff-12:

Reference: Exhibit B, Tab 8, Schedule 1, pages 7-8
Exhibit B, Tab 8, Schedule 1, Table 4

Preamble:

PUC Transmission included four types of adjustments to account for non-comparable items in the analysis of comparable station construction projects.

Question(s):

a) PUC Transmission included reductions of feeders for each comparative to reduce the number of feeders to two in each case and assigned the cost of $482k for each feeder. Please explain how PUC Transmission determined the cost for each feeder in amount of $482k. What is the date/year associated with this estimate? Please discuss why this is a reasonable estimated cost for each feeder for the four comparable projects considering each project's in-service date.

b) PUC Transmission made reductions of capacitor bank costs for each of the four comparable projects and assigned the cost of $1.3M for each capacitor bank. Please explain how PUC Transmission determined the cost for each capacitor bank in amount of $1.3M. What is the date/year associated with this estimate? Please discuss why this is a reasonable estimated cost for each feeder for the four comparable projects considering each project's in-service date. How many capacitor banks are included in the proposed Tagona West TS?

c) PUC Transmission removed real estate cost only from the Tagona West TS in the comparison. Please confirm that there was no real estate cost component in any of the four comparable projects. Please provide related reference.

PUC Transmission Response(s):

a) The noted cost of $482k per feeder is the cost that HONI used in their application EB-2018-01178 for the Barrie Area Transmission Upgrades (the "BATU" application) which PUC Transmission has referenced for comparison purposes in its application. At Appendix B, Tab 7, Schedule 1, Table 9 in the BATU application, HONI used this cost to adjust for different feeder quantities of the comparator stations. The adjustment resulted in a "Total Comparable Cost" for each station before adjusting for inflation. PUC Transmission used this same adjustment principle to determine a Total Comparable Cost for each comparator station prior to adjustment for inflation.

b) The noted cost of $1.3M per capacitor bank is the cost that HONI used in their application EB-2018-01178 for the Barrie Area Transmission Upgrades (the "BATU" application) which PUC Transmission has referenced for comparison purposes in its application. At

Appendix B, Tab 7, Schedule 1, Table 9 in the BATU application, HONI used this cost to adjust for different capacitor quantities of the comparator stations. The adjustment resulted in a "Total Comparable Cost" for each station before adjusting for inflation. PUC Transmission used this same adjustment principle to determine a Total Comparable Cost for each comparator station prior to adjustment for inflation.

c) The evidence presented by HONI in the BATU application, EB-2018-0117, at pages 17 through 21 of Exhibit B, Tab 7, Schedule 1 confirms there were no real estate costs included in any of the four station comparators. All the stations involved construction within the existing property limits at each site, and therefore there were no real estate costs associated with the work.

Staff-13:

Reference: Exhibit B, Tab 9, Schedule 1, pages 1-4

Preamble:

In relation to the "Economic Evaluation – Minimum Connection Facilities", PUC Transmission explains that, based on Algoma Steel's credit rating of B-, a 10-year revenue horizon was used (based on a "medium high risk" classification), as well as the OEB's approved network service rate in the 2024 preliminary Uniform Transmission Rate (UTR). Based on the total connection costs of $55.4 million for the Minimum Connection Facilities, the economic evaluation indicates a net present value (NPV) of $41.07 million. PUC Transmission notes no capital contribution will therefore be required from Algoma Steel. The supporting table in the application provides inputs.

Question(s):

a) Please provide a simple table that shows the total estimates rate revenues and the total cost to show how the NPV was determined.

b) The OEB issued the most recent UTR Decision and Rate Order on January 18, 2024.[2] Please provide the results of the economic evaluation based on the updated Network Service Rate.

PUC Transmission Response(s):

a) Table 2 on page 4 of Exhibit B, Tab 9, Schedule 1 provides the details pertaining to the 10-year Discounted Cash Flow analysis for the minimum connection facilities attributable to Algoma Steel's connection to the Tagona West TS.

A simplified version of Table 2 is included below to highlight the estimated net revenue (i.e. PV of Net Operating Cash which is Annual Revenue less Annual OM&A) compared to total costs and benefits (which include Annual Municipal Taxes, Annual Income Taxes, Annual Capital and Annual CCA Tax Shield).

[2] EB-2023-0222

OPERATING CASH FLOW		Item #
PV of Net Operating Cash: $M	118.98	A
PV of Taxes: $M	31.55	B
PV of Operating Cash Flow: $M	87.43	C
CAPITAL		
PV of Capital: $M	55.40	D
CCA TAX SHIELD		
PV of CCA Tax Shield (Appendix 5 Formula): $M	9.03	E
Project Net Present Value: $M	41.07	F
Project Net Present Value (NPV) = A - B - D + E		

b) As stated at Exhibit B, Tab 9, page 2 of the Application, PUC Transmission used the 2024 Preliminary UTR Rates, EB-2023-0222, which included the following UTRs: Network $5.76; Line Connection $0.95; Transformation Connection $3.21.

The most recent UTR Decision and Rate Order of January 18, 2024 confirmed these same UTRs, therefore the economic evaluation presented in this application is still valid under the new rates.

<u>Staff-14:</u>

Reference: Exhibit B, Tab 9, Schedule 1, pages 5-7
Exhibit B, Tab 9, Schedule 1, page 6, Table 2

Preamble:

In relation to the “Network Pool Rate Impact” and “Impact on Typical Residential Customer”, PUC Transmission notes that it has applied the OEB approved 2024 preliminary UTRs.

Question(s):

a) Please update the analysis for Network Pool Rate Impact and Impact on Typical Residential Customer with the most recent UTRs and discuss the results.

b) What is the discount rate used in Table 2 of Exhibit B, Tab 9, Schedule 1? How was the discount rate derived?

PUC Transmission Response(s):

a) As per PUC Transmission’s response to Staff-13 (b) above, the analysis presented in this application is still valid for the most recent UTRs.

b) Since PUC Transmission is a newly formed transmitter without an established financial profile, PUC Transmission used a 5% after-tax discount rate as a proxy for the discount rate that could result, taking into account its deemed debt-to-equity ratio, debt and preference share costs and Board-approved rate of return on equity, once such parameters are established.

However, PUC Transmission notes that HONI’s application EB-2023-0198 (Waasigan S.92) used an after-tax discount rate of 5.65% for the discounted cash flow (DCF) analysis. Using 5.65% in PUC Transmission’s DCF results in a Net Present Value (NPV) of $40.64M compared to an NPV of $41.07M at 5.00%.

<u>Staff-15:</u>

Reference: Exhibit B, Tab 2, Schedule 1, page 1

Preamble:

The reference above notes that the cost of the HOSSM Station Project's common elements will be included in rate pools consistent with the evidence provided by PUC Transmission.

Question(s):

a) Please confirm what elements of the Project are expected to be included in PUC Transmission's rate base (e.g., portions of Third Line TS costs, transmission line costs and/or Tagona West TS).

b) Please confirm when PUC Transmission expects to file its first rate application related to the Project.

PUC Transmission Response(s):

a) All Third Line TS costs are to be included in HOSSM's rate base. All costs for the new 230 kV transmission line and the Tagona West TS are to be included in PUC Transmission's rate base.

b) PUC Transmission plans to file its first rate application approximately 12 months prior to the projected in-service date of June 2027.

Staff-16:

Reference: Exhibit E, Tab 3, Schedule 1

Preamble:

In the above noted reference, PUC Transmission notes the status of the existing/new easements acquisition and land purchase.

Paragraph 2 of the above noted reference states:

> Negotiations with PUC Distribution Inc. aimed at acquiring the existing easements have not yet occurred. Negotiations with property owners for new land rights were initiated in early November 2023. Each property owner has been or will be provided with a copy of the appraisal report for information. PUC Transmission will negotiate a mutually acceptable and reasonable fee for the proposed acquisition which will be documented and confirmed by the associated agreements noted below.

Question(s):

a) Please provide an update on the status of negotiations with PUC Distribution Inc. with respect to acquiring the existing easements from PUC Distribution Inc.

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 PUC Transmission 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 PUC Transmission advise affected property owners of the availability of independent legal advice (ILA) and that PUC Transmission 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.

PUC Transmission Response(s):

a) As of this response date, negotiations with PUC Distribution Inc, relative to acquiring the existing easements have not yet started in earnest. PUC Distribution has indicated it is agreeable to transferring the easements, however the terms remain to be determined.

b) As of the filing of this document, the following is the status of new easements acquisition process:

- Formal offers have been delivered to all property owners;
- 7 of the required 20 easements have accepted the offer of purchase and easement option agreements have been signed by both parties, closing is conditional upon approval of this application for leave to construct;
- 6 easements are in preliminary negotiations; and
- the balance of easement offers are under consideration.

As of the filing of this document, the following is the status of new land purchase process:

- An offer of purchase for the northerly approx. half of the land required for the Tagona West TS has been accepted City Council, closing is conditional upon approval of this application.
- An offer of purchase for the southerly approx. half of the required station property has been submitted to the owner and is under consideration.

There are no contentious issues at this point in the process.

c) Confirmed, please see Schedule E, Tab 4, Schedule 1, Attachment 1, Form of Easement, Schedule B, clause 28 and Schedule E, Tab 4, Schedule 1, Attachment 2, Form of Purchase Option Agreement, Schedule B, clause 27.

d) Confirmed, please see response to part (c) above.

e) Property owners are advised in writing. Please see response to part (c) above for details.

Staff-17:

Reference: Chapter 4 Filing Requirements, section 4.3.5.3 Land-related Forms
Exhibit E, Tab 4, Schedule 1, Attachments 1 and 2

Preamble:

Reference 1 (Chapter 4 Filing Requirements) states:

> The applicant should confirm if the forms of agreements are consistent with any similar agreements approved by the OEB in previous LTC decisions. If so, the case number of the Decision and Order in which they were approved must be referenced. In the instance in which two or more parties file a joint application, clarity must be provided as to which party, or parties, is/are requesting approval of the forms of agreements.

Reference 2 above contains the land right agreements that PUC Transmission proposes to use to obtain the new land rights for the PUC Tx Project.

Question(s):

a) Please confirm whether the forms of agreements in Attachment 1 and Attachment 2 are consistent with any similar agreements approved by the OEB in previous leave to construct decisions. If yes, please provide the details of the reference with the OEB case number of the Decision and Order in which forms of agreements were approved. Please also advise whether there are any substantive differences between the previously approved forms and the forms that PUC Transmission has included in this application for approval.

PUC Transmission Response(s):

a) The forms of agreement, specifically the Easement Option Agreement and Option Agreement – Fee Simple Parcel are consistent with the forms of agreement in OEB file EB-2022-0140 (Exhibit E, Tab 1, Schedule 1 of the Application) and approved by the Order issued November 24, 2022 in this file.

The forms of agreement in attachments 1 and 2 are consistent with the forms of agreement approved in OEB file EB-2022-0140 by Order issued November 24, 2022. The substantive differences between the agreements in this application and those approved in OEB file EB-2022-0140 are as follows:

- Easement Option Agreement

  (i) There is no reference to a Compensation Incentive Agreement as a standalone Compensation Incentive Agreement is not being utilized in this matter.

(ii) Paragraph 3 of the draft Easement Option Agreement has been inserted which provides for an incentive payment to the Owner.

(iii) A provision has been added at paragraph 28 in Schedule B of the draft Easement Option Agreement allowing the Owner the opportunity to obtain Independent Legal Advice and Representation and PUC (Transmission) LP agreeing to reimburse the Owner its reasonable costs in connection with obtaining such independent legal advice or representation.

(iv) The Easement Terms at Schedule "C" paragraph 1(a) of the draft Easement Option Agreement have been amended to remove refence to telecommunication cables.

(v) The Easement Terms at Schedule "C" paragraph 1(b) of the draft Easement Option Agreement have been amended to remove PUC (Transmission) LP's ability to "selectively" cut trees and rather it has been changed to simply allow for PUC (Transmission) LP to cut trees, among other things rights set out in the said paragraph.

(vi) Paragraph 4 in Schedule "C" in the Easement Option Agreement approved in EB-2022-0140 regarding agricultural purposes has been removed.

(vii) Paragraphs 4 and 5 in Schedule "C" of the draft Easement Option Agreement were inserted and provide for an indemnity by PUC (Transmission) LP in favour of the Owner as well as insurance requirements for PUC (Transmission) LP.

- Option Agreement – Fee Simple Parcel (this form is consistent with the Option Agreement—Fee Simple Corridor approved in EB-2022-0140)

(i) Rather than reference to a Fee Simple Corridor, this has been changed simply to a Fee Simple Parcel to accommodate an acquisition of any required fee simple parcel.

(ii) There is no reference to a Compensation Incentive Agreement as a standalone Compensation Incentive Agreement is not being utilized in this matter.

(iii) Paragraph 3 of the draft Option Agreement—Fee Simple Parcel has been inserted which provides for an incentive payment to the Owner.

(iv) A provision has been added at paragraph 27 in Schedule B of the draft Option Agreement—Fee Simple Parcel allowing the Owner the opportunity to obtain Independent Legal Advice and Representation and PUC

(Transmission) LP agreeing to reimburse the Owner its reasonable costs in connection with obtaining such independent legal advice or representation.

Staff-18:

Reference: Exhibit C Tab 4 Schedule 1, pages 13-15
Exhibit C Tab 4 Schedule 1 Table 2
Chapter 4 Filing Requirements, section 4.3.2.8

Preamble:

Exhibit C Tab 4 Schedule 1 states that HOSSM has provided two comparable projects for the Third Line TS work, 1) the Orangeville TS Refurbishment Project and, 2) the Martindale TS T21, T23 & Component Replacement, both constructed by Hydro One. HOSSM notes that the inflation adjustment factors used for comparator projects are consistent with the inflation parameters described in Exhibit B, Tab 8, Schedule 1, Table 2 of this application.

Question(s):

a) Section 4.3.2.8 of Chapter 4 Filing Requirements requires the applicant to provide the cost of three most recent comparable projects. HOSSM has provided two comparable projects in this application. Please provide another comparable project for the analysis and expand Table 2 of Exhibit C, Tab 4, Schedule 1 accordingly. Otherwise, please explain why a third comparable project cannot be provided.

b) Please provide the detailed calculations for the Escalation Adjustment of the two comparable projects as presented in Table 2 of Exhibit C, Tab 4, Schedule 1 (in amount of $30,096k and $40,379k).

c) For the two comparable line construction projects, please update the "Escalation Adjustment" and "Total Comparable Project Costs" rows in Table 2 of Exhibit C, Tab 4, Schedule 1 with the IPI inflation factors listed in the manner set out in Table 1 of Exhibit B, Tab 8, Schedule 1 (OEB IPI inflation factors without adjustment for two-year lag). Please provide the calculations.

HOSSM Response(s):

a) In footnote #21 to Exhibit C, Tab 4, Schedule 1 Pg. 14 of this Application's prefiled evidence, HOSSM noted that the inflation adjustment factors used for comparator projects were consistent with the inflation parameters described in Exhibit B, Tab 8, Schedule 1, Table 2 of the Application. However, due to a clerical error the incorrect Table 2 was filed in the prefiled evidence. An updated Table 2 - Costs of Comparable Station Projects, has been provided below in the response to part a), using IPI rates which are consistent with those used in the prefiled evidence at Exhibit B, Tab 8, Schedule 1, Table 2 of this Application. Further details are provided in part a) below.

In the response to part c), below, tables A through C, have been updated to provide the escalation adjustments to comparator projects using the IPI rate inflation factors which are consistent with those used in the forementioned prefiled exhibit, namely Exhibit B, Tab 8, Schedule 1, Table 2 of this Application.

Lakehead TS has been added to the amended Table 2 of Exhibit C, Tab 4, Schedule 1. In addition, the East West Tie – Marathon TS project costs have been updated to reflect a COVID-19 adjustment , which is based on final cost variance analysis for that project.

Lakehead TS was modified to accommodate the new EWT lines. The scope included adding a new diameter and five new breakers on the 230 kV side of the station for termination of the new circuits and re-termination of the existing circuits, similar to the subject PUC project at Third Line TS. Both projects include the upgrade of station service equipment and the installation of a new relay building.

Table 2 - Costs of Comparable Station Projects

Project	**Third Line TS** **230kV PUC Connection**	**Martindale TS** **T21, T23 & Component Replacement**	**East West Tie Project - Marathon TS**	**East West Tie Project – Lakehead TS**
Technical	Yard Reconfiguration: 5x 230kV breakers, 2x SS Transformer Replacements, 1x PCT Building, Station Expansion, 3 Line Relocations	44kV yard including: 2x Autotransformers, 5x 230kV breakers, 1x PCT Building, 5x SS Transformers, Station Expansion	New 230kV Yard: 12x 230kV breakers, 2x SS Transformers, 1x PCT Building	Yard Reconfiguration: (8) 230kV Circuit Breakers, (1) Reactors, (20) Disconnect Switches, (8) CVTs, AC/DC Station Service, (1) P&C Building
Location	Upgrade situated on expanded station footprint	Upgrade situated on expanded station footprint	Upgrade situated on expanded station footprint	Upgrade situated on existing station footprint
Project Surroundings	Mostly rural	Suburban/Residential	Mostly rural	Suburban/Residential
In-Service Date	June 2027	Oct 2021	March 2022	March 2022
Estimate or Actual	**Estimate**	**Actual**	**Actual**	**Actual**
OEB-Approved Cost Estimate	N/A	$73,800k[3]	$61,530k[4]	$50,935[2]
Total Capital Project Cost	**$73,407k**	**$74,580k**	**$71,800k**	**$57,700k**
Non-Comparable Costs				
230 kV Breakers (at average unit cost of $1,190k)	-	-	(8,330)	(3,570)
New DESN Yard	-	(9,000)	-	-
Autotransformers (at average unit cost of $7,000k)	-	(14,000)	-	-
SS Transformers (at average unit of $800k)	-	(2,400)	-	-
Service Road	-	(2,000)	-	-
Removals	(477)	(3,500)	-	-
Covid-related Construction Costs	N/A	N/A	($1,372)	(1,372)
Total Project Cost	**$72,930k**	**$43,680**	**$62,098**	**$52,758**

Escalation Adjustment[5]	-	15,183[6]	19,768[4]	16,795[4]
Total Comparable Project Costs	**$72,930k**	**$58,863k**	**$81,866**	**$69,553**

b) The calculations for the “Escalation Adjustment” values for the two comparator station projects, noted in Table 2 of Exhibit C, Tab 4, Schedule 1 of the prefiled evidence, are provided in Tables A and B below.

As noted above, the comparable project cost total for Marathon TS has been updated along with the appropriate inflation adjustment factors. The below tables are provided as a response to OEB Staff’s question, however, they no longer remain current.

Table A - Martindale TS - Cost Escalation Adjustment Workings

End Period	Cost ($M)	Months Elapsed	Inflation Rate (%)	Cost Escalation ($M)
30-Oct-2021	43.68			
Q2 2022	45.98	8	7.90%	2.30
Q2 2023	54.03	12	17.50%	8.05
Q2 2024	58.40	12	8.10%	4.38
Q2 2025	63.13	12	8.10%	4.73
Q2 2026	68.25	12	8.10%	5.11
Q2 2027	73.78	12	8.10%	5.53
			Subtotal	***30.10***
Opening Cost ($M)	43.7	*A*		
Inflation Increase ($M)	30.1	*B*		
Closing Cost ($M)	73.8	*C = A+B*		

[3] EB-2019-0082, ISD SR-02-Station Reinvestment Projects, Page 9.
[4] EB-2017-0194 – Exhibit B, Tab 7, Schedule 1, pg. 4.
[5] Inflation adjustment factors used for comparator projects are consistent with the inflation parameters described in Exhibit B, Tab 8, Schedule 1, Table 2 of this Application.
[6] The escalation adjustment has been updated to use inflation adjustment factors for comparator projects using IPI rates which are consistent with those used in the prefiled Exhibit B, Tab 8, Schedule 1, Table 2 of this Application.

Table B - Marathon TS - Cost Escalation Adjustment Workings

End Period	Cost ($M)	Months Elapsed	Inflation Rate (%)	Cost Escalation ($M)
30-March-2022	63.47			
Q2 2022	64.72	3	7.90%	1.25
Q2 2023	76.05	12	17.50%	11.33
Q2 2024	82.21	12	8.10%	6.16
Q2 2025	88.87	12	8.10%	6.66
Q2 2026	96.07	12	8.10%	7.20
Q2 2027	103.85	12	8.10%	7.78
			Subtotal	***40.38***
Opening Cost ($M)	63.5	*A*		
Inflation Increase ($M)	40.4	*B*		
Closing Cost ($M)	103.9	*C = A+B*		

c) The calculations for the "Escalation Adjustment" values for three comparator station projects using IPI inflation factors listed in the manner set out in Table 1 of Exhibit B, Tab 8, Schedule 1 are provided in Tables A and B below, along with a third project (as requested), Lakehead TS, located in Table C.

Table A - Martindale TS - Cost Escalation Adjustment Workings using IPI inflation factors

End Period	Cost ($M)	Months Elapsed	Inflation Rate (%)	Cost Escalation ($M)
30-Oct-2021	43.68			
Q2 2022	45.25	8	5.4%	1.57
Q2 2023	47.70	12	5.4%	2.44
Q2 2024	50.27	12	5.4%	2.58
Q2 2025	52.99	12	5.4%	2.71
Q2 2026	55.85	12	5.4%	2.86
Q2 2027	58.86	12	5.4%	3.02
			Subtotal	**15.18**
Opening Cost ($M)	43.7	*A*		
Inflation Increase ($M)	15.2	*B*		
Closing Cost ($M)	58.9	*C = A+B*		

Table B - Marathon TS - Cost Escalation Adjustment Workings using IPI inflation factors

End Period	Cost ($M)	Months Elapsed	Inflation Rate (%)	Cost Escalation ($M)
30-March-2022	62.10			
Q2 2022	62.94	3	5.4%	0.84
Q2 2023	66.33	12	5.4%	3.40
Q2 2024	69.92	12	5.4%	3.58
Q2 2025	73.69	12	5.4%	3.78
Q2 2026	77.67	12	5.4%	3.98
Q2 2027	81.87	12	5.4%	4.19
			Subtotal	**19.77**
Opening Cost ($M)	62.1	*A*		
Inflation Increase ($M)	19.8	*B*		
Closing Cost ($M)	81.9	*C = A+B*		

Table C - Lakehead TS - Cost Escalation Adjustment Workings using IPI inflation factors

End Period	Cost ($M)	Months Elapsed	Inflation Rate (%)	Cost Escalation ($M)
30-March-2022	52.76			
Q2 2022	53.47	3	5.4%	0.71
Q2 2023	56.36	12	5.4%	2.89
Q2 2024	59.40	12	5.4%	3.04
Q2 2025	62.61	12	5.4%	3.21
Q2 2026	65.99	12	5.4%	3.38
Q2 2027	69.55	12	5.4%	3.56
			Subtotal	***16.79***
Opening Cost ($M)	52.8	*A*		
Inflation Increase ($M)	16.8	*B*		
Closing Cost ($M)	69.6	*C = A+B*		

Staff-19:

Reference: Exhibit C, Tab 4, Schedule 1, pages 12-13

Preamble:

In Exhibit C, Tab 4, Schedule 1, HOSSM identified four key risks and associated potential impact on the proposed project.

Question(s):

a) Please discuss the options that HOSSM employed or plans to employ to mitigate the key risks.

HOSSM Response(s):

a) *Approvals and permits* – Relevant environmental approvals from the City of Sault Ste Marie and the Sault Ste Marie Conservation area have been acquired. This risk is being actively managed.

Outage Constraints – Outages during the winter and summer are unlikely to be granted due to regional high load demand in the area. Therefore, key project milestones requiring system outages will be scheduled during the fall and spring (known as shoulder demand periods) and will be proactively managed.

Material Delivery Timelines – Contingency has been allocated to account for potential recovery measures on site if major equipment is delayed.

Pricing Variations – Reasonable contingency has been allocated to account for an increase in major and minor material prices.

Staff-20:

Reference: Exhibit C, Tab 4, Schedule 1, pages 11-18
Exhibit C, Tab 4, Schedule 1, Table 4

Preamble:

Question(s):

a) Please discuss how the total HOSSM Station Project cost of $73.4M as well as the cost of each of the four individual cost elements ($17.4M, $19.2M, $18.2M and $18.6M) were estimated.

b) Please discuss how the allocation percentages associated with three common elements for each project component (#1, #2 and #3) were determined. Why were the common costs equally split among/between all beneficiaries?

HOSSM Response(s):

a) The total HOSSM Station Project cost of $73.4M was generated by completing an Association for the Advancement of Cost Engineering ("AACE") Class 3 cost estimate. Engineering packages were created to define the required detailed scope for the Project and the Class 3 estimate was based on that scope, taking into consideration the Project Schedule and the required in-service date. Class 3 estimates are compiled by task based on preliminary design quantities and schedule, each of the tasks were then mapped to the four listed cost elements; Common station elements, East yard, West yard and non-Common station elements in order to calculate the individual cost elements provided in Exhibit C, Tab 4, Schedule 1, Table 4.

b) With the PUC-T connection project, planned refurbishments and the New Transmission Line Project all being targeted to be completed and in-service between 2027 and 2029, it was essential to coordinate all three projects and think of them collectively during the planning and estimation phase.

The HOSSM Station Project work at Third Line TS is divided into East yard, West yard, Common station elements and PUC-T driven work. For work scope where more than one project will benefit, each sub-project would trigger the same change/upgrade, even in the absence of the other station sub-project not being undertaken. Therefore, there is no quantifiable difference in the benefit provided to the individual sub-projects (i.e. no practical capacity ratings to be pro-rated), hence HOSSM maintained an equal cost split among the benefiting projects as an appropriate allocator. Two examples are provided below to illustrate this concept.

Example 1 - East Yard – Re-location of the existing circuits is required for both the PUC-T Connection Project and the New Transmission Line Project. In absence of either of these projects being executed simultaneously, the line re-location work would still need to be carried out, thus equally benefiting both projects.

Example 2 - West Yard - Electrical and Civil work (including the backfill of the adjacent ravine to bring it up to the Third Line Station elevation) – Both the PUC-T Connection Project and the New Transmission Line Project require the creation of a new diameters (two in total). To add these diameters, the station yard footprint must be expanded westward. Both projects will benefit equally from this expansion to enable the accommodation of both work projects. In absence of either project this expansion work would still need to be carried out, even for the addition of one new diameter. This work will equally benefit both projects, and an equal division of the costs was used by HOSSM to allocate to those individual projects.

Staff-21:

Reference: Exhibit C, Tab 4, Schedule 1, pages 18-20

Preamble:

The application states that Algoma Steel requested that new load associated with its EAF be supplied by HOSSM until PUC Transmission's proposed 230 kV line is completed. The application also notes Algoma Steel's EAF (and Lake Superior Power CGS) are connected to HOSSM's system at Clergue TS and discusses the need for HOSSM to perform work on two Remedial Action Schemes (RAS) and additional work at Clergue TS.

It further notes that HOSSM is seeking an exemption from section 11.2.1 of the Transmission System Code (TSC) which would require Algoma Steel to pay bypass compensation in relation to 30 MW of the new load associated with its new EAF that will be served by HOSSM until PUC Transmission's proposed project is completed. HOSSM states that it currently expects to serve Algoma Steel's 30 MW for three years which is when Algoma Steel is expected to change the connection point from HOSSM's Clergue TS to PUC Transmission's Tagona West TS.

Question(s):

a) Please provide a table that separately lists each RAS and the other work to be done at Clergue TS. Include the estimated cost for each in the list and identify the portion of the cost that will be allocated to Algoma Steel in the table.

b) Please explain the two RAS and the work to be done at Clergue TS in more detail. Please also clarify if the work at the Clergue TS and the two RAS are solely attributable to serving the 30 MW of new load.

c) The application indicates that Algoma Steel is already connected to HOSSM's Clergue TS and the 30 MW is incremental load that would be served by HOSSM. If that is a correct understanding, please clarify Algoma Steel's existing load at Clergue TS.

d) Please clarify if the sole reason for the request for the exemption from the bypass compensation requirement in section 11.2.1of the TSC is related to Clergue TS not being a permanent solution to meet Algoma Steel's needs. If it is not the sole reason, please elaborate.

e) If completion of PUC Transmission's Tagona West TS is materially delayed beyond three years, is HOSSM requesting the exemption remain in place regardless of how long it takes until Algoma Steel is able to connect its EAF to Tagona West TS and shift the 30 MW of load from HOSSM's Clergue TS?

f) If any investments are solely related to serving the 30 MW of new load, please identify them and clarify what purpose those assets will serve after Algoma Steel connects to PUC Transmission to supply that load.

g) Please clarify if 30 MW is the total amount of remaining Available Capacity on Clergue TS at this time.

h) Please confirm there is a total of 45 MW of new load associated with Algoma Steel that will connect to HOSSM's transmission system, and 15 MW will remain on HOSSM's system at Patrick Street TS.

i) The application states the costs initially incurred for Phase 1 (which includes the 30 MW at Clergue TS) will continue to be recuperated via the CCRA between HOSSM and Algoma Steel in relation to the new load at Patrick Street TS. Please clarify what costs will continue to be recuperated including whether any relate to Clergue TS.

j) Based on the expected three-year timeframe, please provide the estimated rate revenues HOSSM expects to receive in relation to the 30 MW of new load.

HOSSM Response(s):

a) Table below identifies work for each RAS and work at Clergue TS, and the cost allocation to Algoma Steel.

RAS/Station	**Work**	**Approximate Cost ($M)**	**Allocation to Algoma Steel (%)**	**Reason**
Third Line RAS (Third Line TS)	Changes to Contingency Detection and Control Actions	3.7	25%	Changes in the RAS are also required for correcting exiting system deficiencies
Northwest RAS (Lakehead TS)	Changes to Contingency Detection and Control Actions	1.9	16%	
Clergue TS	Perform grounding study and install additional grounding as required by the study	0.1	100%	Work triggered by Algoma Steel only

b) The Northwest RAS and the Third Line RAS are remedial action schemes used to trip load, generation and/or circuits during system contingencies. As identified in the Independent Electrical System Operator (IESO)'s System Impact Assessment, modifications to each of these RASs will address the connection of the EAF CTS facility to the HOSSM system and will address existing system deficiencies in the region when applying North American Electric Reliability Corporation ("NERC") planning standards. Thus, the cost is apportioned between the customer and the transmission rate pool relative to the scope consistent with the Transmission System Code ("TSC"). HOSSM's cost contribution will cover the scope addressing the existing system needs to meet the NERC standards and the customer's cost contribution will cover the cost that is caused by their new or modified connection to the transmission system. The cost attributed to the customer addresses the direct requirements to supply 30 MW of load.

Algoma Steel was allocated 25% ($0.925M) of the total cost of the modification of the Third Line TS RAS based on the percentage of new selections in the RAS matrix due to them, as well as, the entire cost for tele-protection equipment dedicated to Algoma Steel. Algoma Steel was allocated 16% ($0.3M) of the total cost of the modification of the Northwest RAS based on the percentage of new selections in the RAS matrix due to them, as well as, the entire cost for tele-protection equipment dedicated to Algoma Steel. In addition to the RAS modifications, a grounding study was required at Clerge TS to verify adequacy of the ground grid for re-termination of Algoma Steel's generators from Patrick Street TS to LSP CGS. The cost of this scope is fully allocated (100%) to Algoma Steel.

c) Presently, only Lake Superior Power Customer Generating Station (i.e. LSP CGP – owned by Algoma Steel) is connected to Clergue TS via 115 kV circuits, via COGEN#1 and COGEN#2. Currently, Algoma Steel is not connected to HOSSM's Clergue TS as a load customer. The new EAF facility will be built and connected to the main 115 kV bus at LSP GS. The maximum EAF facility load of 140 MW will be partially offset by 110 MW of generation from LSP GS, meaning the new 'net' load drawn from the 115 kV circuits at Clerge TS will be 30 MW.

d) Correct, the Clergue TS connection is not a permanent solution.

e) Yes, HOSSM wish for the exemption to remain in place if completion of Tagona West TS is delayed.

f) The investments as described in the responses to part a) and part b), above, are related to serving the 30 MW of load. After Algoma Steel moves its load to the Tagona West TS, the RAS modifications will still be required under various system conditions including planned outages.

g) Clergue TS has two step-down transformers at the station and the station is connected by two 115 kV transmission circuits, Clergue No.1 and Clergue No. 2 to Patrick Street TS. The step-down transformers and two circuits are connection assets. Since the EAF facility and LSP CGS connect at the Clergue TS 115 kV bus, the available transformation capacity at Clergue TS remains unchanged.

There is supply capacity available for the new Algoma Steel 30 MW load. It will be supplied from the Clergue TS 115 kV bus via circuits Clergue No.1 and Clergue No. 2. Based on HOSSM's Transmission Customer Connection Procedure the total normal supply capacity for Clergue No.1 and Clergue No.2 is approximately 20 MW before voltage compensation is required while the circuits themselves can supply 96 MW. Therefore, after this new 30 MW load connection there is remaining capacity, provided sufficient voltage compensation is in place.

h) The total new load added to the HOSSM system is 42 MW, 30 MW at Clergue TS and 12 MW at Patrick Street TS. The 12 MW load connected to Patrick Street TS will remain connected to that station after the completion of Tagona West TS.

i) When the EAF facility is connected to Clergue TS, HOSSM will earn revenue on the total load of 42 MW through its rates. Once Tagona West TS is completed, the EAF facility load will move from HOSSM's Clergue TS to PUC's Tagona West TS. The Patrick Street TS load of 12 MW will be maintained and HOSSM will continue to earn revenue on that load through its rates. No further revenue will be recuperated from Clergue TS.

j) An estimate of rate revenues for HOSSM cannot be provided since transmitters, including HOSSM, do not directly bill customers. The estimated UTR revenue for this new load is $201,000/month (as calculated using the following; 30,000 kW * (UTR-Network [using a $5.78/kW rate] + UTR-Line [using a $0.95/kW rate]), which will be added to Ontario's total rates revenue by pool, which is collected by the IESO and remitted to transmitters via the revenue disbursement allocators established in the UTR Schedule A. HOSSM's 2024 revenue allocation is 1.867% of the UTR-Network revenues, and 2.068% of the UTR-Line and UTR-Connection revenues, per EB-2023-0222 issued on January 18, 2024. HOSSM is currently in a 10-year deferred rebasing period since integration (i.e. from 2016 to 2026), which does not allow any updates to its UTR revenue requirement and charge determinants.

<u>Staff-22:</u>

Reference: Exhibit C, Tab 4, Schedule 1, page 2
Exhibit C, Tab 4, Schedule 1, pages 20-22

Preamble:

Reference 1 states that "HOSSM is seeking OEB approval of a Regulatory Account for the station scope of work that facilitate Project Component #3, the New Transmission Line Project. The new regulatory account will consist of two sub-accounts".

Reference 2 states that

- The first sub-account will be called the "Priority Transmission Line Project – Station Costs" (or "PTLPDA-Costs') and will track capital costs associated with the New Transmission Line Project, as part of the HOSSM Station Project, prior to being placed in rate base.

- PTLDA-Costs - If the New Transmission Line Project is completed and in serviced i.e., included in a transmitter's rate base, then the regulatory account will not record any balances and there will be no need for any disposition of the sub-account in the future.

- The second sub-account will be called the "Priority Transmission Line Project – Station Revenue Requirement" (or "PTLPDA-Revenue'), which will record any post-in-service Revenue Requirement attributable to the New Transmission Line Project's facilities that have not been included in an OEB approved transmission rate filing.

PTLDA-Revenue - if at the time of in-service, the OEB has not approved a transmission rate filing that includes those costs. HOSSM will record the revenue requirement earned as part of the HOSSM Station Project (which includes scope for Component #3), in a sub-account up until such time they can be included in a future OEB-approved transmission revenue requirement application.

Question(s):

a) In HOSSM's view, what is the difference between a deferral account and a tracking account?

b) In HOSSM's view, is there a difference in the manner and timing of disposition between the deferral sub-account and the tracking sub-account?

c) Please confirm whether Hydro One can use its internal tracking account to achieve the same objectives of these two sub-accounts. If confirmed, please provide HOSSM's thought of withdrawing the request of the DVA. If not confirmed, please explain what can be achieved using the DVA that could not otherwise be achieved using the internal tracking account(s).

d) Please explain HOSSM's current approach to tracking costs to date for the New Transmission Line Project.

a) What are the pros and cons of establishing and using the PTLPDA-Costs Account compared to this approach?

e) Please explain HOSSM's approach to tracking the revenues of the New Transmission Line Project if the requested approval for both subaccounts are not approved in this proceeding.

f) Please provide any precedent for the requested deferral account that HOSSM is aware of. Please provide the EB # and references to the related evidence.

HOSSM Response(s):

a) The new PTLPDA-Costs Sub-Account HOSSM is seeking will be multi-dimensional and have the functionality of both tracking, and if required, deferral account characteristics. This regulatory account is only in respect of, and applicable to, the new priority transmission line project outlined in Ministerial Directives and Order in Council – per Appendix B of Exhibit C, Tab 4, Schedule 1. Hydro One's transmission licence has been amended by the OEB required Hydro One to develop and seek approvals for:

A new 230 kilovolt (kV) transmission line from Mississagi Transformer Station to Third Line Transformer Station, including associated station facility expansions or upgrades required at the terminal stations.

The tracking of costs in the account, will provide visibility on the costs associated with this scope of the Project. If, for reasons beyond the control of HOSSM, the Project does not proceed, then the Regulatory Account would transition to a deferral account (e.g. will record the value of the expenditures). Hydro One would then seek recovery/disposition of those balances in a future HOSSM rates proceeding.

b) When the PTLPDA-Costs Sub-Account is used as a tracking account, there are effectively no 'real' balances in the account, and therefore there is no expectation that HOSSM will need to seek disposition or recovery of the costs being tracked. When the Project is completed it would be recorded in HOSSM's future Rate Base and included in a future OEB-approved revenue requirement application. However, as mentioned above in part a) above, should the Project not be completed and not form part of HOSSM's future rate base for reasons beyond the control of HOSSM, HOSSM would then seek recovery of those Project costs via disposition of those costs in the regulatory account. i.e. the tracked costs would become 'real' debit balances, as shown in the draft accounting order[7]. This entry demonstrates the process for the regulatory account to record a 'real' debit balance via the transfer of capital costs incurred from HOSSM's *Account 2205 - Construction Work in Progress* account. At that point in time the regulatory account transitions from a 'tracking' account to a 'deferral' account.

c) HOSSM does not understand OEB staff's reference to, or what is meant by, HOSSM's "internal tracking account'.

HOSSM does not have an 'internal' account that affords it the protection of performing work pertaining to a priority project that falls under the direction of an Order In Council. The PTLPDA-Costs Sub-Account being requested is similar in nature to accounts that Hydro One transmission has OEB approval for (see part f, below). HOSSM is seeking approval for this sub-account to track and recover prudently incurred Project costs in the event the Project is not completed. The approval of the account and the functionality therein, provides HOSSM the cost recovery assurances required to move forward with incurring costs during the Project's development and construction life span in the most cost-effective manner for developing a transmission system for the future.

HOSSM is not aware of any 'internal' accounts, or OEB generic accounts that would afford it the functionality it is requesting with this regulatory sub-account.

d) Currently any station costs associated with the new transmission line priority project are developmental in nature and are recorded, like all HOSSM capital costs, in *Account 2205 - Construction Work in Progress*. For HOSSM to move forward with material project expenditures for the Project, including those outlined in this Application, it requires cost recovery certainty. In this case, HOSSM proposes to achieve this through approval of this PTLPDA-Costs Account. This account is akin to the regulatory sub-accounts approved by the OEB in Hydro One's Affiliate Transmission Project ("ATP") Regulatory Account[8].

The advantage of approving the PTLPDA-Costs Account in this application hearing is that momentum of the Project is maintained along with the contemplated cost efficiency of performing this work for the new priority transmission line simultaneously with other required work scope within Third Line TS. The disadvantage of the OEB not establishing this PTLPDA-Costs Account in a timely manner may lead to unanticipated delays to the in-service of the new priority transmission line Project as well as incurring additional costs in the future by not taking advantage of the synergy savings available to complete the work simultaneously.

e) If HOSSM's requested regulatory account for recording revenues is not approved as part of this proceeding, HOSSM will need to evaluate the risk profile of incurring those

[7] Exhibit C, Tab 4, Schedule 1, Appendix A, - the first accounting entry at the top of Pg. 2.
[8] EB-2021-0169.

expenditures (for the scope of the new priority transmission line project) without the reassurance of their recovery, i.e. either via regulatory account disposition, or via rates recovery (in a future revenue requirement application, once the project is in-service).

As a regulated utility, HOSSM does not believe that spending capital beyond its OEB-approved levels without a mechanism for cost recovery assurance is appropriate transmission system stewardship. As such, HOSSM would not be in a position to move forward with the construction of this station scope element of the full project scope, as outlined in this Application. This could lead to the delay of in-servicing and connection of the new priority transmission line project unless there were another form of compensation in order to recover its project expenditures. HOSSM is not aware of any other mechanism that would afford it sufficient regulatory certainty, as to how these revenues would be recovered.

f) The precedents for the Regulatory Accounts HOSSM are seeking approval for are:

i) Waasigan Transmission Tracking Deferral Account in EB-2019-0151, which the OEB approved on September 12, 2019 for Hydro One Transmission.

ii) The OEB subsequently approved Hydro One Transmission to transfer the Waasigan account to a new ATP account in EB-2021-0169, whereby the ATP Account would also establish similar sub-accounts for other projects of similar nature i.e. those projects that were not expected to form part of the rate base of Hydro One in the future. Hydro One's ATP Account also facilitates other subsequent priority projects provided in Ministerial Order In Councils[9]

[9] Such as Chatham x Lakeshore, two Longwood by Lakeshore projects, GTA East, two North West transmission line projects (Mississagi by Third line project and the Hamner by Mississagi project). Please refer to EB-2021-0169 for more details on the specific of those projects.

<u>Staff-23:</u>

Reference: Exhibit C, Tab 4, Schedule 1, Appendix A

Preamble:

Reference states that “This two new regulatory 1508 sub-accounts will be named and function as following

- *Priority Transmission Line Project – Station Costs – Account*
  This sub-account will track HOSSM-incurred costs related to the New Transmission Line Project. This account will be a contra-account that will have identical and offsetting entries, and as such no net debit or credit balances will exist while HOSSM Management continue to believe the New Transmission Line Project will be completed. This ‘tracking’ sub-account allows for tracking and reporting of capital attributable to the New Transmission Line Project.

- *Priority Transmission Line Project – Station Revenue Requirement – Account*
  This sub-account will record the annual revenue requirement attributable to the level of in-service New Transmission Line Project costs incurred by HOSSM. It will exist until a time when HOSSM receives OEB approval to include those assets into the rate base on which a future HOSSM revenue requirement is set.

The proposed accounting entries are as following:

1. The contra-account entries will facilitate the tracking of capital costs incurred and allocated to the New Transmission Line Project

   DR 1508 Other Regulatory Assets, Sub-Account “PTLPDA – Station Costs - Account”

   CR 1508 Other Regulatory Assets, Sub-Account “PTLPDA – Station Costs - Account”

2. Should the New Transmission Line Project not proceed, for reasons beyond HOSSM management’s control, the entry below records the removal of capital costs from HOSSM’s Construction Work in Progress (“CWIP”) Account and become balances in the PTLPDA – Station Costs – Account

   DR 1508 Other Regulatory Assets, Sub-Account “PTLPDA – Station Costs - Account”

   CR 1508 Construction Work in Progress

Question(s):

a) Please explain how HOSSM uses the contra-account entry (entry #1 above) to facilitate the tracking of capital costs incurred and allocated to the new Transmission Line Project, considering that both the debit and credit of the entry are recorded in the same account.

b) For entry #2, please clarify what Account 1508 Construction Work in Progress is and if HOSSM has obtained the approval of this account. If so, please provide the EB # where the OEB had approved this account.

c) For entry #2, please explain how HOSSM uses the entry to record the removal of capital costs from HOSSM's CWIP, considering that the account number for both the debit and credit sides of that entry are the same.

d) Please explain what HOSSM means by "Should the New Transmission Line Project not proceed, for reasons beyond HOSSM management's control". Please provide the reasons that are outside of HOSSM's control.

HOSSM Response(s):

a) Refer to Exhibit I, Tab 1, Schedule 22.

b) The Construction Work in Progress (CWIP) account described by HOSSM in Appendix A as having nomenclature of Account 1508 is an error. The CWIP account should have been described as *Account 2055 - Construction Work in Progress*, consistent with the OEB-approved Accounting Procedures Handbook[10]. HOSSM has updated its Appendix A, Draft Accounting Order, to rectify the clerical error, and is included as an Attachment to this response.

c) Given the response in part b), above, outlining that the CWIP's account nomenclature should be 2055, HOSSM's believes this OEB staff question is no longer applicable because the entry referenced will effectively result in CWIP costs recorded in *Account 2055 - Construction Work in Progress* being transferred to the regulatory sub-account of 1508 as debit balances, for disposition in a future HOSSM rate proceeding.

d) The New Transmission Line Project has been identified by the Minister of Energy as a priority project, through the issuance of an Order in Council to the OEB to amend Hydro One's transmission licence. If there is a change in government direction, whereby the asset is no longer deemed necessary or the IESO believes that other options are available that would result in better solution, Hydro One could be asked not to proceed with the

[10]https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/Accounting-Procedures-Handbook-Elec-Distributors-20120101.pdf

Mississagi to Third Line Project. This would be an action that is outside the control of HOSSM.

With the regulatory account functionality afforded to it, as described above, and in Exhibit I, Tab 1, Schedule 22, HOSSM would have the ability to make an application to the OEB for the future disposition of costs recorded in the account. The OEB would then adjudicate if those costs were prudently incurred, and if they are eligible for recovery by HOSSM.

Until such a theoretical situation occurs, with the approval of the regulatory accounts and the certainty it affords, HOSSM will be in a position to move ahead with the station work at Third Line TS required to connect the new transmission line project, consistent with the OIC, and would only stop those activities should an externality warrant it, which by definition would be beyond HOSSM's management control.

APPENDIX A

Draft Accounting Order - Accounting Entries

HOSSM is requesting the Board approve two new regulatory deferral sub-accounts, under the OEB-established Account ‘1508, Other Regulatory Assets’ control account, of the OEB’s Uniform System of Accounts.

This two new regulatory 1508 sub-accounts will be named and function as follows;

1. *Priority Transmission Line Project – Station Costs – Account*
   This sub-account will track HOSSM-incurred costs related to the New Transmission Line Project. This account will be a contra-account that will have identical and offsetting entries, and as such no net debit or credit balances will exist while HOSSM management continue to believe the New Transmission Line Project will be completed. This ‘tracking’ sub-account allows for tracking and reporting of capital attributable to the New Transmission Line Project.

2. *Priority Transmission Line Project – Station Revenue Requirement – Account*
   This sub-account will record the annual revenue requirement attributable to the level of in-service New Transmission Line Project costs incurred by HOSSM. It will exist until a time where HOSSM receives OEB approval to include those assets into the rate base on which a future HOSSM revenue requirement is set.

The following outlines the proposed accounting entries for this variance account.

USofA #	Account Description
DR 1508	Other Regulatory Assets, Sub-Account “PTLPDA – Station Costs - Account”
CR 1508	Other Regulatory Assets, Sub-Account “PTLPDA – Station Costs - Account”

Initially the sub-account will be classified as a Contra-account, whereby no balances (either DR or CR, will exist. The contra-account entries will facilitate the tracking of capital costs incurred and allocated to the New Transmission Line Project. The DR and CR entries will be identical and offset each other, such that no balance will accrue in the account while there is confidence in the need for the project, and that management believe it will be in-serviced.

USofA #	Account Description
DR 1508	Other Regulatory Assets, Sub-Account "PTLPDA – Station Costs - Account"
CR 2205	Construction Work in Progress

Should the New Transmission Line Project not proceed, for reasons beyond HOSSM management's control, the above entries record the removal of capital costs from HOSSM's Construction Work in Progress ("CWIP") Account and become balances in the PTLPDA – Station Costs - Account (i.e. no longer will the account act as a contra-account for tracking of capital costs only). These costs represent costs HOSSM would seek OEB approval and recovery in a future S.78 Application. The PTLPDA – Station Costs - Account would then record DR balances.

USofA #	Account Description
DR 17XX and 19XX	Transmission and General Plant Asset Range of Accounts
CR 2205	Construction Work in Progress

At the point where HOSSM Station Project capital costs are placed in-service and pertain to the New Transmission Line Project, the above entries recognize the transfer of those project capital costs from HOSSM's 2205 - Construction Work in Progress ("CWIP") Account to the applicable General Plant and Transmission Fixed Asset Account ranges.

USofA #	Account Description
CR/DR 1508	Other Regulatory Assets, Sub-Account "PTLPDA – Station Revenue Requirement Account"
DR/CR 4110	Transmission Services Revenue

Entry to record the revenue requirement impact of the in-service of the New Transmission Line Project of the HOSSM Station Project that will facilitate the connection of New Transmission Line Project. The capital driving this revenue requirement was no included in the rate base on which HOSSM's current OEB-approved revenue requirement was based. The revenue requirement attributable to any in-service capital of the New Transmission Line Project will be recorded in the 1508 sub-account called *PTLPDA – Station Revenue Requirement Account,* which is a separate and distinct sub-account to that of the *PTLPDA – Station Costs - Account*.

USofA #	Account Description
DR/CR 6035	Other Interest Expense
CR/DR 1508	Other Regulatory Assets, Sub-Account "PTLPDA – Station Revenue Requirement Account"

To record interest improvement on the principal balance of the amounts included in the PTLPDA – Station Revenue Requirement Account.

<u>Staff-24:</u>

Reference: Chapter 4 Filing Requirements, Section 4.3.6

Preamble:

The above reference requires all applicants to provide evidence to the OEB that connection of the proposed transmission project will not affect the reliability of the IESO-controlled grid. This takes form of a System Impact Assessment (SIA) conducted by the IESO as a part of the IESO Connection Assessment and Approval process.

Question(s):

a) Is there an IESO SIA report completed for the HOSSM Station Project? If yes, please provide this report. If no, please explain why the SIA report is not needed for the HOSM Station Project in this leave to construct application.

HOSSM Response(s):

a) Yes, there is an IESO SIA report that covers the HOSSM Station Project work associated with the connection of the PUC-T line (described in evidence as component #1). As part of PUC's SIA application (CAA ID: 2021-704), HOSSM submitted the proposed configuration modifications to the 230 kV yard at Third Line TS, described in Exhibit C, Tab 4, Schedule 1. The final SIA report for CAA ID: 2021-704 has been provided in Exhibit F of this Application.

The station is planned to undergo further reconfiguration to accommodate the New Transmission Line Project, (described in evidence as component #3). This is in addition to the preliminary work described with this leave to construct application.

A separate SIA will be required, and furnished within, a future s.92 application for the New Transmission Line Project.

<u>Staff-25:</u>

Reference: Decision on Issues List, EB-2023-0360, issued April 16, 2024

Preamble:

In this application, PUC Transmission and HOSSM have applied for leave to construct approvals. The reference above includes the OEB's standard conditions of approval for transmission leave to construct applications. OEB staff proposes that the standard conditions be placed on PUC Transmission and HOSSM in relation to this application. The standard conditions are reproduced below for convenience:

1. PUC Transmission and HOSSM shall fulfill any requirements of the SIA and the CIA, and shall obtain all necessary approvals, permits, licences, certificates, agreements and rights required to construct, operate and maintain the project.

2. Unless otherwise ordered by the OEB, authorization for leave to construct shall terminate 12 months from the date of the Decision and Order, unless construction has commenced prior to that date.

3. PUC Transmission and HOSSM shall advise the OEB of any proposed material change in the project, including but not limited to changes in: the proposed route, construction schedule, necessary environmental assessment approvals, and all other approvals, permits, licences, certificates and rights required to construct the project.

4. PUC Transmission and HOSSM shall submit to the OEB written confirmation of the completion of the project construction. This written confirmation shall be provided within one month of the completion of construction.

5. PUC Transmission and HOSSM shall designate one of their employees as project manager who will be the point of contact for these conditions, and shall provide the employee's name and contact information to the OEB and to all affected landowners, and shall clearly post the project manager's contact information in a prominent place at the construction site.

Question(s):

b) Please comment on the above standard conditions in relation to this application. If PUC Transmission and/or HOSSM do/does not agree with any of the draft conditions of approval, please identify the specific conditions that PUC Transmission and/or HOSSM disagree(s) with and explain why. For conditions in respect of which PUC Transmission and/or HOSSM would like to recommend changes, please provide the proposed changes.

HOSSM Response(s):

a) Hydro One has no concerns with the standard conditions of approval for this Project, related to the HOSSM scope of work, as contained, and described within this Application.

PUC Transmission Response(s):

a) PUC Transmission is in agreement with these standard conditions.

INTERROGATORY RESPONSES TO ESSAR POWER CANADA LTD.

1.EPC-1:

Reference: Exhibit B Tab 3, Schedule 1, p. 1
Exhibit B, Tab 4, Schedule 1, p. 1

Preamble:

PUC states the proposed new 230 kV transmission line and new 230 kV transformer station (the "**Project**") will provide the increased transmission supply capacity and improve system reliability required to meet the increasing short-term and longer-term power demands of the significant load growth forecasted for development within Sault Ste. Marie.

Question(s):

a) Please provide all working papers, analysis, and reports written or carried out by PUC regarding the forecasted "significant" load growth within Sault Ste. Marie.

b) Did PUC consider the impact of the Project on forecasted load growth in Northeast and Eastern Ontario in addition to within Sault Ste. Marie? If yes, please discuss how the Project will respond to the forecasted load growth. If no, please explain why not.

c) Please provide all working papers, analysis, and reports written or carried out supporting PUC's position that the Project will provide the increased transmission supply capacity required to meet both short-term and longer-term power demands.

d) Did PUC consider the impacts of the Project on power generators that currently provide capacity within Sault Ste. Marie and Northeastern Ontario? If yes, please discuss PUC's analysis of the impacts. If no, please explain why not.

PUC Transmission Response(s):

a) Please see the response to OEB Staff-1 and 4. PUC Transmission's affiliate is PUC Distribution, who is in the best position to understand what load growth will occur in the City of Sault Ste. Marie. PUC Distribution works with local businesses and government to forecast load growth and attract new business.

b) Yes, please refer to the system impact assessment ("SIA") filed as part of Exhibit F, Tab 1, Schedule 1 of the Application, the SIA addendum filed on April 6, 2024 and Bulk Plan cited at Exhibit H, Tab 1, Schedule 1 of the Application for the relevant Project considerations in relation to Northeast and Eastern Ontario.

c) Please see the responses to OEB Staff 2 and 4. PUC Transmission's Project will be capable of supporting up to 400 MVA of new load with the initial phase of construction under this application. Provision is included in the design to allow for future upgrading of the line and station up to approximately 750 MVA when required to connect additional new loads in the future.

d) There is insufficient power generation within Sault Ste. Marie to supply Algoma Steel's additional new load of approximately 280 MW and PUC's Project will facilitate the connection of new generators within Sault Ste. Marie in addition to supplying Algoma Steel's needs. Connection to the Project also allows Algoma Steel to obtain generation from the IESO bulk grid where the electricity is generated from primarily zero-carbon sources.

1.EPC-2:

Reference: Exhibit B, Tab 2, Schedule 1
Exhibit B, Tab 3, Schedule 1

Preamble:

PUC states that the immediate need for increased transmission capacity is driven by the substantial increase in load at Algoma Steel ("**Algoma**") due to the addition of EAFs that will replace existing blast furnaces.

In support of the need for the Project, PUC included a letter of support from Algoma for the application and the Project (the "**Letter**").

Question(s):

a) Please provide all documents exchanged between PUC, including any PUC-related entities ("**PUC Entities**"), and Algoma in the creation of the Letter.

b) Did Algoma approach PUC or PUC Entities ahead of publishing the various media releases referenced in the Application? If yes, please provide all documents, including electronic communications and Board minutes etc. related to Algoma's contact with PUC and/or PUC Entities describing and supporting Algoma's need for the Project.

c) Please provide all other working papers, analysis, and reports written or carried out by Algoma provided to PUC or PUC Entities in support of the Project.

PUC Transmission Response(s):

a) Communications between PUC Transmission and Algoma are not relevant as they do not provide information that the OEB may require to determine the issues in this matter.

b) No, Algoma does not require permission from PUC or PUC Entities to publish the various media releases provided in the Application.

c) Working papers, analysis, and reports written or carried out by Algoma are not relevant to the matters at issue and do not form part of the evidence in the Application.

2.EPC-3:

Reference: Exhibit B, Tab 5, Schedule 1

Preamble:

PUC notes that there is no viable alternative to the Project.

PUC further notes that the construction required to upgrade or expand the existing 115 kV facilities cannot be undertaken without significant power outages to all customers served from the Third Line TS and that these outages would be economically unacceptable for these customers.

PUC states that upgrading the existing 115kV transmission line would also be technically unfeasible due to physical constraints of existing rights-of-way and existing clearances to privately owned buildings or existing utilities and infrastructure.

Question(s):

a) Please provide details of all alternatives to the Project considered by PUC and discuss why each of these alternatives were determined to be unviable.

b) Did PUC consider any non-wires solutions (**NWS**) in addition to the Project? If yes, please discuss the NWS and why they were not considered part of a viable solution. If no, please explain why not.

c) Please explain why the outages would be economically unacceptable for affected customers. In your answer, please provide details regarding how PUC made this determination and discuss PUC's analysis of why the outages would be economically unacceptable.

d) Please provide all working papers, analysis, and reports written or carried out by PUC regarding PUC's determination that upgrading the 115kV transmission line would be more technically unfeasible than other similar projects with similar constraints. In your answer, please provide details of all communications with potentially persons and entities, including any relevant utilities.

PUC Transmission & HOSSM Response(s):

a) PUC Transmission considered a number of alternatives to the Project, which are summarized below;

1) Use the existing 115 kV supply to the Patrick Street station.

- As set out in Exhibit B, Tab 2, Schedule 1, page 1 of the Application, the existing 115 kV supply to Patrick Street does not have the required additional capacity to serve full operations of the new EAF station, i.e. approx. 280 MW.
- Therefore, this option was ruled out.

2) Upgrade the existing 115 kV supply at 115 kV.

- This option would require additional circuits to be added to the existing poles and the existing conductors would have to be changed to larger and/or bundled conductors. The existing poles are not adequately designed for the additional weight and wind loading and would have to be replaced within the existing right-of-way. This could not be done with the existing 115 kV line in place and may require additional land rights to be obtained.
- This option would also require significant, very costly upgrades to the 115 kV system at the Third Line Station including the addition of more transformers.
- Given that the existing 115 kV line would need to be dismantled, removed and replaced, an extended outage of a 115kV circuit would reduce the capacity in the 115kV system requiring extended and unacceptable outages to existing customers.

3) Upgrade the existing115 kV supply to 230 kV.

- This would require the conversion of the existing 115 kV circuits out of Third Line Station and Clergue Station to 230 kV on the existing poles. The poles are not adequately sized for 230 kV and would have to be replaced within the existing right-of-way. This could not be done with the existing 115 kV line in place.
- Furthermore, the existing space available for clearance from existing buildings is inadequate for this higher voltage level within the existing right-of-way.
- Due to the physical restrictions and the unacceptable outages to existing customers due to removal of the existing 115 kV system, this option was ruled out.

4) Connect to the PUC Distribution system.

- The existing PUC Distribution system does not have the capacity to supply the additional 280 MW load.
- Therefore, this option was ruled out.

PUC Transmission Response(s):

b) PUC Transmission considered non-wires options as alternatives to the Project, which are summarized below;

1) Expand the existing Lake Superior Power (LSP) generating facility or construct a new gas-fired generating facility.

- It is PUC Transmission's understanding that the existing natural gas supply line to the region is insufficient to supply the additional generation requirements.
- Furthermore, this option would be counterproductive to Federal and Provincial objectives to reduce green-house-gas emissions.
- Due to the above, this option was ruled out.

2) Construct hybrid generation, i.e. PV and/or wind generation with battery energy storage (BES).

- This option would require:
    - Substantial vacant lands, in the order of thousands of acres, to accommodate the amount of PV panels required to generate the required energy.
    - Extensive number of wind turbines to produce the required energy.
    - Substantial amount of BES to provide the amount of energy storage required to convert the intermittent nature of the generation sources to continuous energy output required by the new EAF load.
- Due to the above, this option was ruled out.

3) Construct additional hydro generation facilities.

- There is insufficient locally available waterpower for the required amount of generation.
- A transmission line would still be needed.
- Therefore this option was ruled out.

4) Construct a modular nuclear generation facility within the region.

- Algoma Steel requires additional energy for the new EAF Station as soon as possible.
- While small modular reactors (SMRs) hold great potential to provide cost-effective clean energy generation, the technology is still undergoing development, and a viable installation would not be available within a reasonable timeframe to meet Algoma's needs.
- It is not clear where the waste fuel from such a facility would be stored.
- Due to the above, this option was ruled out.

c) Please see answer to part (a) above.

d) Please see answer to part (a) above.

2.EPC-4:

Reference: Exhibit B, Tab 5, Schedule 1
Environmental Study Report (The “Report”), p. 4

Preamble:

The Report indicates that no alternative to generate the additional required electricity from “green sources” in the area needed by Algoma has been identified.

Question(s):

a) Please provide details of all alternative power sources considered by PUC in the area that could provide the additional required electricity.

b) How does PUC and/or WSP define “green sources”?

c) Are there any non-“green” sources that could provide the additional required electricity other than the potential of Algo’s natural gas LSP combined cycle power plant to generate its own additional electricity? If yes, please provide details. If no, please explain why not.

PUC Transmission Response(s):

a) PUC Transmission is not aware of any viable alternative green power sources within Sault Ste. Marie that could provide the additional electricity required by Algoma Steel’s new electric arc furnaces. Please refer to the answers to EPC-2 (b) above for details on options considered and ruled out.

b) PUC Transmission considers “green sources” as zero-carbon based sources.

c) It is PUC Transmission’s understanding that there is insufficient natural gas supply in the area to generate the amount of electricity required for Algoma Steel’s new electric arc furnaces from non-green sources.

5.EPC-5:

Reference: Exhibit B, Tab 1, Schedule 1, p. 4

Preamble:

PUC states that the Project and HOSSM Station Project are required to provide adequate transmission supply capacity and improve system reliability to accommodate new loads in the city of Sault Ste. Marie and the surrounding area

Question(s):

a) Please discuss the current state of system reliability and/or quality of electricity services within Sault Ste. Marie.

b) Please explain how and provide the metrics used to determine that the HOSSM Station Project and the Project will improve system reliability within Sault Ste. Marie.

c) Will the Project and/or HOSSM Station Project impact reliability and quality of electricity service in Northeastern and Eastern Ontario. If yes, please discuss. If no, please explain why not.

PUC Transmission Response(s):

a) PUC Transmission notes that the current transmission system downstream of the Third Line Station is inadequate to supply the additional power needs for Algoma Steel's new electric arc furnaces, or any other significant load within Sault Ste. Marie. While reliability of the transmission system in the area meets applicable standards, the lack of additional capacity precludes economic growth from large industrials within the city of Sault Ste. Marie.

PUC Transmission's new transmission facilities will provide the increased capacity required to allow Algoma and other industrial loads and generators proposed for development within Sault Ste. Marie to connect to the provincial grid with the associated reliability required under the Transmission System Code.

b) As noted in response to part (a) above, there is insufficient capacity downstream of the Third Line Station and the Project will correct this constraint to allow more load customers and generators to connect at the transmission level. The new facilities will provide expanded electricity service within the City and ensure the existing system reliability is maintained.

The Project and the HOSSM Station Project will not impact electricity service upstream of the Third Line Station.