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BY EMAIL AND RESS

December 19, 2023

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Marconi,

EB-2023-0198 – Hydro One Networks Inc. Leave to Construct Application – Waasigan Project – Interrogatory Responses

In accordance with Procedural Order ("PO") No.2 issued November 24, 2023, and the OEB's approval of Hydro One's request for a two business-day extension beyond PO No.2, for submitting its interrogatory responses, please find attached an electronic copy of responses provided by Hydro One to interrogatory questions posed by intervenors and Ontario Energy Board ("OEB") Staff.

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

Exhibit	Tab	Intervenor
I	1	OEB Staff
I	2	Kurt Krause
I	3	Neighbours on the Line ("NOTL")
I	4	Métis Nation of Ontario ("MNO")
I	5	Larry Richard

Hydro One has, pursuant to Rule 10 of the Ontario Energy Board's (OEB) Rules of Practice and Procedure (the "**Rules**") and the OEB's Practice Direction on Confidential Filings dated December 17, 2021 (the "**Practice Direction**"), requested confidential treatment of certain information contained in its responses to OEB staff interrogatories as follows;

- **OEB Staff 4 (a)** – seeking information regarding the calculation of the Project's annual line losses;
- **OEB Staff 9(a) and (b)** pertaining to requests for Engineering, Procurement and Construction ("EPC") contract pricing information, and;
- **OEB Staff 22(a), 25(f) and 30(e)** pertaining to non-public forward-looking financial information.

Additionally, in accordance with subsection 6.1.2, 6.1.4 and 6.1.7 of the Practice Direction and subsections 10.01 and 10.02 of the Rules, Hydro One has proposed that the confidential versions of its responses to OEB staff interrogatories 9(a) and (b) be disclosed to ***only counsel*** for OEB Staff from whom the OEB accepts a Declaration and Undertaking.

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

Sincerely,

Joanne Richardson

Cc: All registered parties
Gordon Nettleton and Reena Goyal, McCarthy Tétrault LLP, counsel for HONI

OEB STAFF INTERROGATORY - 01

Reference:

1. Exhibit B-1-1, Page 1
2. Exhibit B-3-1, Attachment 1

Preamble:

Hydro One Networks Inc. (Hydro One) states that the Waasigan Project has been declared a priority project for Hydro One to develop and seek approvals for by the Minister of Energy. The Order in Council (OIC) from the Minister of Energy is attached as Exhibit B, Tab 3, Schedule 1, Attachment 1.

Interrogatory:

a) Please confirm if the Waasigan Project has been declared a priority project under section 96.1 of the OEB Act.

Response:

a) Not confirmed. As explained in Exhibit B, Tab 3, Schedule 1, Attachment 1, on December 13, 2013, the Minister of Energy with the approval of the Lieutenant Governor in Council, issued an Order in Council ("OIC") pursuant to the authority described in section 28.6 of the *OEB Act*. The OIC directed the Board to amend Hydro One's transmission license in order to allow Hydro One to proceed with all necessary development and regulatory approvals required for the Project. The directives set out in the OIC also required the Board and Hydro One to work co-operatively with the then Ontario Power Authority ("OPA") to establish the scope and timing of the Northwest Bulk Transmission Line Project, (which the Waasigan Project is part of) in accordance with the recommendations of the OPA.

   Section 96.1 of the *OEB Act* is not referenced in the OIC because this provision came into effect in 2015, after the OIC's issuance.

   Hydro One's reference to the Project being characterized as a "priority project" is based on descriptions found in correspondence from the Deputy Minister of Energy dated December 11, 2013, (see Exhibit B, Tab 3, Schedule 1, Attachment 2), correspondence from the OPA (now IESO) dated October 1, 2014 (see Exhibit B, Tab 3, Schedule 1, Attachment 5), correspondence from the IESO dated October 24, 2018 (see Exhibit B, Tab 3, Schedule 1, Attachment 6), the IESO's Integrated Regional Resource Plan for the Northwest Region dated January 2023 (See Exhibit H, Tab 1, Schedule 1, Attachment 1), and the IESO Report dated July 26, 2023 (see Exhibit B, Tab 3, Schedule 1, Attachment 9). The latter Report specifically describes the IESO's

findings regarding need and alternatives to the Waasigan Project. The referenced OPA/IESO correspondence also refer to the fact that the terms “priority project” were consistently used to describe the Northwest Bulk Transmission Line Project, in both the 2013 and 2017 Long Term Energy Plans.

OEB STAFF INTERROGATORY - 02

Reference:

1. Exhibit B-1-1, Pages 2-3

Preamble:

Hydro One states that the transmission line facilities comprising the Project will be owned by a future limited partnership through which Hydro One will offer 50% equity ownership to nine First Nation partners. Gwayakocchigewin Limited Partnership (GLP) represents eight of the nine First Nations partnering with Hydro One on the Waasigan Transmission Line Project. The ninth First Nation partner is Lac des Mille Lacs First Nation (LDMLFN).

Hydro One further states that, as of the time of filing the application, the limited partnership has not yet been finalized Hydro One is not able to provide commercial details.

Interrogatory:

a) Please indicate if the limited partnership agreement may impact the project cost estimates provided at Exhibit B, Tab 7, Schedule 1 pp. 1-3 of the application. If applicable, please discuss the likelihood, magnitude and reasons for these potential cost impacts.

b) Please confirm if “transmission line facilities” noted in the preamble above refers to only line assets or both line and station assets. Please also confirm if Hydro One’s offer for 50% equity ownership to the nine First Nation partners is only for the line assets in the Project.

Response:

a) Any limited partnership agreement made with GLP and LDMLFN is expected to be negotiated on a commercial basis, designed to provide parties the opportunity to make equity investments based on actual incurred Project costs and equity return levels that are ultimately established by the Board through its cost of capital and rate-setting processes. As such, Hydro One is not anticipating any limited partnership agreement to impact the Project cost estimates provided in Exhibit B, Tab 7, Schedule 1. A goal of the limited partnership structure is to afford collaboration with GLP and LDMLFN, and thus expedite the time in which the Project may be constructed and placed in-service. These outcomes may lead to Project cost efficiencies that provide benefits to ratepayers.

b) Confirmed. The reference refers to only line assets, not station assets. The 50% equity partnership pertains to line project facilities.

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OEB STAFF INTERROGATORY - 03

Reference:

1. Exhibit B-10-1, Pages 1-2
2. EB-2021-0169, Amended Evidence, Page 3

Preamble:

Hydro One states that, in its OEB-approved 2023-27 transmission rate application[1] (in the Transmission System Plan – Section 2.1.3), Hydro One disclosed that the Project's line scope was expected to be owned by, and included in, the rate base of a new future OEB-transmission licensed partnership, while Project station cost will be in-serviced into Hydro One's transmission rate base.

Hydro One states that "like the Stations costs, during construction, all transmission line project costs will be tracked in Hydro One's OEB-approved ATP Account [Affiliate Transmission Partnership regulatory account]".

At the second reference, Hydro One states:

> The ATP Account would have two sub-accounts, the (i) *ATP – Project Development, Preliminary Engineering and Planning Work deferral account, and the (ii) ATP – Project Construction Costs tracking account*. Each of these sub-accounts, as described below, will record costs by individual project.

In this Application, Hydro One notes that the OEB approved the Externally Driven Work Regulatory (EDWR) Account allowing Hydro One to capture the annual revenue requirement amounts for in-serviced assets in Hydro One's rate base, for disposition in a future transmission revenue requirement application.

Interrogatory:

a) Please confirm that only line costs are proposed to be recorded and tracked in the ATP Account. If not confirmed, please explain.
   i. The ATP Account was established through the OEB's decision in the EB-2021-0169 proceeding. If applicable, please describe how Hydro One's proposal to assign station costs to the ATP Account is consistent with the OEB finding from that decision that stated:

[1] EB-2021-0110.

> The OEB finds that requiring Hydro One to include transmission stations in the scope of the proposed ATP Account would be inappropriate. Should Hydro One wish to include transmission station ownership in any future project development with a New Partnership, Hydro One would have to seek OEB's approval regarding the expansion of the proposed ATP Account scope.

b) If applicable, please specify the total project costs as shown in Table 2, Table 3, Table 4 and Table 5 of Exhibit B, Tab 7, Schedule 1 that will be assigned to the ATP Account and those that will be assigned to Hydro One's rate base.

c) Please clarify when Hydro One anticipates the disposition of the deferral sub-account balance in the ATP Account will be sought.

d) The ATP Account decision found that the costs of "development work" related to the Waasigan Project would be tracked in the ATP Account. Per Hydro One's application in that proceeding, development work included items such as engineering work and preparation for regulatory approvals (Environmental Assessment and Leave to Construct).
   i. Please indicate if the costs associated with development work are reflected in Table 2, Table 3, Table 4 and Table 5 of Exhibit B, Tab 7, Schedule 1 and if not, why not.

Response:

a) Confirmed.

b) Project costs, shown in Tables 2 and 4, pertain to line assets which will be tracked in the ATP Account. At in-service those transmission line assets will become owned by a future limited partnership which will offer a 50% equity ownership to nine First Nation partners. Project costs, shown in Tables 3 and 5, pertaining to station assets will not be tracked in the ATP Account. At in-service, the transmission station assets will be included in Hydro One's rate base.

c) During Project construction, both line and station capital expenditures will be recorded in Hydro One's Construction Work in Progress ("CWIP") Account. The OEB-approved ATP Account functions only as a deferral and variance account for tracking line assets and is expected to have a net zero balance once the Project is placed in service. If the Project is not completed due to reasons beyond Hydro One management's control Project line capital costs tracked in the ATP sub-account for the Waasigan Project would become an **actual** cost (i.e., debit) balance. Under this scenario, Hydro One would then seek recovery of prudently incurred ATP Account amounts. At this time

there are no indicators that this Project will not be completed as planned, and therefore Hydro One has no current intention to seek recovery of any ATP balances.

d) Confirmed.

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OEB STAFF INTERROGATORY - 04

Reference:

1. Exhibit B-5-1, Tables 1 and 2, Pages 3-4

Preamble:

Hydro One provides an incremental NPV analysis of the conductor size alternatives in the application.

OEB staff notes that the NPV analysis methodology used in the reference is consistent with that used in the previously approved LTC - Chatham by Lakeshore application.[1] In both of the applications, Hydro One provided three scenarios using different HOEP prices to calculate NPV values.

OEB staff also notes that Hydro One used a combination of HOEP (wholesale market price) and Global Adjustment (GA) to produce NPV values in its response to interrogatories[2] for its LTC application – Ansonville TS and Kirkland Lake TS A8K/A9K Refurbishment Project.

Interrogatory:

a) Please provide calculations to derive the information in Tables 1 and 2 in the reference.

b) Please reproduce Table 1 to show the Total Capital Cost for each alternative in addition to the Incremental Capital Cost.

c) Please explain why Hydro One is using HOEP as the proxy for the energy price instead of both HOEP and Global Adjustment (GA).
   - OEB staff understand that the IESO uses HOEP within the Net Energy Market Settlement Uplift charge to recover the cost of line losses. However, OEB staff note that there is also a Global Adjustment component to line losses that is recovered from consumers.

d) Please reproduce Table 2 using HOEP+GA instead of HOEP.
   i. Please comment on any significant differences in the NPV values for each alternative using HOEP versus HOEP+GA.
   ii. Please comment whether the NPV analysis between the two types of energy prices yield the same results.

[1] EB-2022-0140, Exhibit B, Tab 9, Schedule 1, pp. 3-5 (May 9, 2022).
[2] EB-2021-0107, Exhibit I, Tab 2, Schedule 5, IRR-ED#5, pp. 3-7 (October 29, 2021).

e) Beyond the NPV analysis, please explain if there are any other considerations in choosing between the four conductor alternatives.

Response:

a) Annual Losses (MWh) – The calculation of the annual losses is performed in an MS Excel workbook and is referred to as Attachment 1 to this response. [Attachment 1 **has been filed confidentially with the OEB in accordance with its *Practice Direction on Confidential Filings***.]

The details of NPV calculations shown in Table 2 of Exhibit B, Tab 5, Schedule 1 are provided in Appendices 1 through 3.

b) Table 1b), below, shows the Total Capital Cost for each conductor, as originally presented in Exhibit B, Tab 5, Schedule 1, Table 1 (Alternative 1 is the preferred solution).

Table 1b) - Analysis of Conductor Alternatives[1]

	NPV Analysis (Input Data)			
	Alt # 1 795 kcmil	**Alt # 2 997 kcmil**	**Alt # 3 1192 kcmil**	**Alt # 4 1443 kcmil**
Total Capital Cost ($M's) - Baseline is Alt#1	$993.7	$993.7	$993.7	$993.7
Add: Incremental Capital Cost ($M's)	0.0	$5.0	$9.5	$12.5
Total Capital Cost ($M's)	**$993.7**	**$998.7**	**$1,003.2**	**$1,006.2**
Incremental OM&A ($M's)	0.0	0.0	0.0	0.0
Annual Losses (MWh)	11,961.4	9,751.1	8,413.8	6,942.8

c) As mentioned in Exhibit B, Tab 5, Schedule 1, p. 4, footnote 4, the HOEP is the only current mechanism to settle line losses and is therefore used in Hydro One's evaluation in its prefiled evidence. Global Adjustment is not used by the IESO for determining the cost of line losses.

The costs associated with system-wide transmission line losses are recovered by the IESO, as part of the IESO Settlement Process, under the Net Energy Market Settlement Uplift charge type. This charge type covers the difference between the amount the IESO pays to suppliers for the commodity and the amount the IESO

charges to the buyers in a given hour. The IESO uses the HOEP within the Net Energy Market Settlement Uplift charge to recover the cost of line losses.

d)

i. The primary reason for Hydro One provided an analysis that used the $120/MWH price to represent the energy cost for losses evaluation was to demonstrate that even if energy prices were to increase in the future, Hydro One's decision of selecting the conductor size as its preferred alternative was the most cost-effective.

The $120/MWH value used in Hydro One's sensitivity analysis exceeds the combined HOEP and GA over the past three years as shown in the table below:

Average HOEP and GA Data

Year	Average Annual HOEP[3]	Average Annual Global Adjustment	Total HOEP + GA
2021[4]	30.1	73.5	103.6
2022[5]	47.3	53.4	100.7
2023[6]	29.5	75.9	105.4

Use of the HOEP and GA actual values, as provided in the above table, yields similar answers to the analysis that Hydro One provided in its prefiled evidence, except that the NPV will turn positive, however that will not occur until a long time after the asset has been in-service. Hydro One's conclusion regarding the optimal conductor size for this Project remains the same i.e. 795 kcmil.

ii. Please see answer to part d-i), above.

e) The main considerations were the IESO ampacity requirements and project costs.

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[3] HOEP data is sourced from the IESO at the following link - http://reports.ieso.ca/public/PriceHOEPAverage/

[4] 2021 GA data is sourced from the IESO at the following link - https://www.ieso.ca/-/media/Files/IESO/Power-Data/data-directory/Global-Adjustment-Values-MWh.ashx

[5] 2022 GA data is sourced from the IESO at the following link - https://www.ieso.ca/-/media/Files/IESO/Power-Data/data-directory/Global-Adjustment-Values-MWh.ashx

[6] 2023 GA data is sourced from the following IESO webpage Power Data (ieso.ca) in the Global Adjustment section. The Annual Average calculation for 2023 was performed as at December 6, 2023.

Attachment 1 – Hydro One's Line Losses Model - Waasigan Project

This model has been filed as a 'live' MS Excel Spreadsheet, and has been filed confidentially with the OEB in accordance with its Practice Direction on Confidential Filings.

Appendices 1 through 3

Appendix 1A - Incremental NPV Analysis between Alternatives 1 & 2 at Energy Price of $47.30

Incremental NPV analysis (in $k)
For 50 Years Ended December 31st, 2076

	Total	Period 0	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Incremental Capital Expenditures for the upsize	(4,986)	(4,986)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental CCA Tax Shield for the upsize	1,313	0	106	97	89	82	76	70	64	59	54	50	46	42	39	36	33	30	28	26	24	22	20	18	17	16	14
Incremental Line Loss Savings for the upsize	9,332	0	114	116	118	121	123	126	128	131	133	136	139	141	144	147	150	153	156	159	162	166	169	172	176	179	183
Net Incremental Impact to Ratepayers for the upsize	**5,659**	**(4,986)**	**219**	**213**	**208**	**203**	**199**	**195**	**192**	**190**	**187**	**186**	**185**	**184**	**183**	**183**	**183**	**183**	**184**	**185**	**186**	**187**	**189**	**191**	**193**	**195**	**197**
Discount Factor Full Year Discount @ 0.057		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value for the upsize		(4,986)	208	191	176	163	151	140	131	122	114	107	101	95	90	85	80	76	72	69	65	62	60	57	54	52	50
Cumulative Incremental Net Present Value for the upsize	**(1,657)**	**(4,986)**	**(4,778)**	**(4,587)**	**(4,411)**	**(4,248)**	**(4,097)**	**(3,957)**	**(3,826)**	**(3,704)**	**(3,590)**	**(3,483)**	**(3,382)**	**(3,287)**	**(3,198)**	**(3,113)**	**(3,033)**	**(2,957)**	**(2,884)**	**(2,816)**	**(2,750)**	**(2,688)**	**(2,628)**	**(2,572)**	**(2,517)**	**(2,465)**	**(2,415)**

Incremental NPV analysis (in $k)
For 50 Years Ended December 31st, 2076

	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	Terminal Value
Incremental Capital Expenditures for the upsize	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental CCA Tax Shield for the upsize	13	12	11	10	9	9	8	7	7	6	6	5	5	4	4	4	3	3	3	3	2	2	2	2	2	12
Incremental Line Loss Savings for the upsize	187	190	194	198	202	206	210	214	219	223	227	232	237	241	246	246	246	246	246	246	246	246	246	246	246	0
Net Incremental Impact to Ratepayers for the upsize	**200**	**202**	**205**	**208**	**211**	**215**	**218**	**222**	**225**	**229**	**233**	**237**	**242**	**246**	**250**	**250**	**250**	**249**	**249**	**249**	**249**	**249**	**248**	**248**	**248**	**12**
Discount Factor Full Year Discount @ 0.057	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value for the upsize	48	46	44	42	41	39	38	36	35	33	32	31	30	29	28	26	25	23	22	21	20	19	18	17	16	1
Cumulative Incremental Net Present Value for the upsize	**(2,368)**	**(2,322)**	**(2,278)**	**(2,235)**	**(2,195)**	**(2,156)**	**(2,118)**	**(2,082)**	**(2,047)**	**(2,014)**	**(1,982)**	**(1,951)**	**(1,921)**	**(1,892)**	**(1,864)**	**(1,838)**	**(1,813)**	**(1,790)**	**(1,768)**	**(1,747)**	**(1,727)**	**(1,708)**	**(1,691)**	**(1,674)**	**(1,658)**	**(1,657)**

Appendix 1B - Incremental NPV Analysis between Alternatives 1 & 2 at Energy Price of $80

Incremental NPV analysis (in $k)
For 50 Years Ended December 31st, 2076

	Total	Period 0	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Incremental Capital Expenditures for the upsize	(4,986)	(4,986)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental CCA Tax Shield for the upsize	1,313	0	106	97	89	82	76	70	64	59	54	50	46	42	39	36	33	30	28	26	24	22	20	18	17	16	14
Incremental Line Loss Savings for the upsize	15,784	0	192	196	200	204	208	212	217	221	225	230	234	239	244	249	254	259	264	269	275	280	286	292	297	303	309
Net Incremental Impact to Ratepayers for the upsize	**12,111**	**(4,986)**	**298**	**293**	**290**	**286**	**284**	**282**	**281**	**280**	**280**	**280**	**280**	**281**	**283**	**285**	**287**	**289**	**292**	**295**	**298**	**302**	**306**	**310**	**314**	**319**	**324**
Discount Factor Full Year Discount @ 0.057		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value for the upsize		(4,986)	282	263	245	230	216	203	191	180	170	161	153	145	138	132	126	120	115	110	105	100	96	92	89	85	82
Cumulative Incremental Net Present Value for the upsize	**109**	**(4,986)**	**(4,704)**	**(4,441)**	**(4,196)**	**(3,966)**	**(3,750)**	**(3,548)**	**(3,357)**	**(3,176)**	**(3,006)**	**(2,845)**	**(2,692)**	**(2,546)**	**(2,408)**	**(2,276)**	**(2,150)**	**(2,030)**	**(1,916)**	**(1,806)**	**(1,701)**	**(1,601)**	**(1,505)**	**(1,412)**	**(1,323)**	**(1,238)**	**(1,156)**

Incremental NPV analysis (in $k)
For 50 Years Ended December 31st, 2076

	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	Terminal Value
Incremental Capital Expenditures for the upsize	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental CCA Tax Shield for the upsize	13	12	11	10	9	9	8	7	7	6	6	5	5	4	4	4	3	3	3	3	2	2	2	2	2	12
Incremental Line Loss Savings for the upsize	316	322	328	335	342	348	355	363	370	377	385	392	400	408	417	417	417	417	417	417	417	417	417	417	417	0
Net Incremental Impact to Ratepayers for the upsize	**329**	**334**	**339**	**345**	**351**	**357**	**363**	**370**	**377**	**383**	**390**	**398**	**405**	**413**	**421**	**420**	**420**	**420**	**419**	**419**	**419**	**419**	**419**	**418**	**418**	**12**
Discount Factor Full Year Discount @ 0.057	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value for the upsize	79	76	73	70	67	65	63	60	58	56	54	52	50	48	47	44	42	39	37	35	33	32	30	28	27	1
Cumulative Incremental Net Present Value for the upsize	**(1,078)**	**(1,002)**	**(929)**	**(859)**	**(792)**	**(727)**	**(665)**	**(604)**	**(546)**	**(490)**	**(436)**	**(385)**	**(334)**	**(286)**	**(240)**	**(195)**	**(154)**	**(114)**	**(77)**	**(42)**	**(8)**	**23**	**53**	**81**	**108**	**109**

Appendix 1C - Incremental NPV Analysis between Alternatives 1 & 2 at Energy Price of $120

Incremental NPV analysis (in $k) For 50 Years Ended December 31st, 2076	Total	Period 0	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Incremental Capital Expenditures for the upsize	(4,986)	(4,986)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental CCA Tax Shield for the upsize	1,313	0	106	97	89	82	76	70	64	59	54	50	46	42	39	36	33	30	28	26	24	22	20	18	17	16	14
Incremental Line Loss Savings for the upsize	23,676	0	288	294	300	306	312	319	325	331	338	345	352	359	366	373	381	388	396	404	412	420	429	437	446	455	464
Net Incremental Impact to Ratepayers for the upsize	**20,003**	**(4,986)**	**394**	**391**	**390**	**388**	**388**	**388**	**389**	**390**	**392**	**395**	**398**	**401**	**405**	**409**	**414**	**419**	**424**	**430**	**436**	**442**	**449**	**456**	**463**	**471**	**478**
Discount Factor Full Year Discount @ 0.057		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value for the upsize		(4,986)	373	351	330	312	295	279	265	251	239	228	217	207	198	189	181	174	166	160	153	147	141	136	131	126	121
Cumulative Incremental Net Present Value for the upsize	**2,269**	**(4,986)**	**(4,613)**	**(4,263)**	**(3,932)**	**(3,621)**	**(3,326)**	**(3,047)**	**(2,782)**	**(2,531)**	**(2,292)**	**(2,064)**	**(1,847)**	**(1,640)**	**(1,442)**	**(1,252)**	**(1,071)**	**(897)**	**(731)**	**(571)**	**(418)**	**(271)**	**(130)**	**6**	**137**	**262**	**383**

Incremental NPV analysis (in $k) For 50 Years Ended December 31st, 2076	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	Terminal Value
Incremental Capital Expenditures for the upsize	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental CCA Tax Shield for the upsize	13	12	11	10	9	9	8	7	7	6	6	5	5	4	4	4	3	3	3	3	2	2	2	2	2	12
Incremental Line Loss Savings for the upsize	473	483	493	502	512	523	533	544	555	566	577	589	600	612	625	625	625	625	625	625	625	625	625	625	625	0
Net Incremental Impact to Ratepayers for the upsize	**487**	**495**	**504**	**513**	**522**	**531**	**541**	**551**	**561**	**572**	**583**	**594**	**605**	**617**	**629**	**629**	**628**	**628**	**628**	**627**	**627**	**627**	**627**	**627**	**627**	**12**
Discount Factor Full Year Discount @ 0.057	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value for the upsize	116	112	108	104	100	97	93	90	87	83	80	78	75	72	70	66	62	59	56	53	50	47	45	42	40	1
Cumulative Incremental Net Present Value for the upsize	**500**	**612**	**720**	**824**	**924**	**1,021**	**1,114**	**1,203**	**1,290**	**1,373**	**1,454**	**1,531**	**1,606**	**1,679**	**1,748**	**1,814**	**1,876**	**1,935**	**1,991**	**2,044**	**2,094**	**2,141**	**2,186**	**2,228**	**2,268**	**2,269**

Appendix 2A - Incremental NPV Analysis between Alternatives 1 & 3 at Energy Price of $47.30

Incremental NPV analysis (in $k)
For 50 Years Ended December 31st, 2076

	Total	Period 0	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Capital Expenditures for the upsize	(9,513)	(9,513)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA Tax Shield for the upsize	2,505	0	202	186	171	157	144	133	122	113	104	95	88	81	74	68	63	58	53	49	45	41	38	35	32	30	27
Line Loss Savings for the upsize	14,979	0	182	186	190	194	198	202	206	210	214	218	222	227	231	236	241	246	251	256	261	266	271	277	282	288	294
Incremental Impact to Ratepayers for the upsize	**7,970**	**(9,513)**	**384**	**372**	**361**	**351**	**342**	**334**	**328**	**322**	**317**	**313**	**310**	**308**	**306**	**304**	**304**	**303**	**304**	**304**	**306**	**307**	**309**	**312**	**314**	**318**	**321**
Discount Factor Full Year Discount @ 0.057		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value for the upsize		(9,513)	363	333	306	281	260	240	223	207	193	181	169	159	150	141	133	126	119	113	107	102	97	93	89	85	81
Cumulative Incremental Net Present Value for the upsize	**(3,936)**	**(9,513)**	**(9,150)**	**(8,817)**	**(8,511)**	**(8,230)**	**(7,970)**	**(7,730)**	**(7,506)**	**(7,299)**	**(7,106)**	**(6,925)**	**(6,755)**	**(6,597)**	**(6,447)**	**(6,306)**	**(6,173)**	**(6,047)**	**(5,928)**	**(5,815)**	**(5,707)**	**(5,605)**	**(5,508)**	**(5,415)**	**(5,326)**	**(5,241)**	**(5,160)**

Incremental NPV analysis (in $k)
For 50 Years Ended December 31st, 2076

	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	Terminal Value
Capital Expenditures for the upsize	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA Tax Shield for the upsize	25	23	21	20	18	17	15	14	13	12	11	10	9	8	8	7	7	6	6	5	5	4	4	4	3	23
Line Loss Savings for the upsize	300	305	312	318	324	331	337	344	351	358	365	372	380	387	395	395	395	395	395	395	395	395	395	395	395	0
Incremental Impact to Ratepayers for the upsize	**325**	**329**	**333**	**337**	**342**	**347**	**353**	**358**	**364**	**370**	**376**	**382**	**389**	**396**	**403**	**402**	**402**	**401**	**401**	**400**	**400**	**400**	**399**	**399**	**399**	**23**
Discount Factor Full Year Discount @ 0.057	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value for the upsize	78	74	71	68	66	63	61	58	56	54	52	50	48	46	45	42	40	38	36	34	32	30	28	27	25	1
Cumulative Incremental Net Present Value for the upsize	**(5,082)**	**(5,008)**	**(4,937)**	**(4,868)**	**(4,803)**	**(4,739)**	**(4,679)**	**(4,620)**	**(4,564)**	**(4,510)**	**(4,459)**	**(4,409)**	**(4,361)**	**(4,314)**	**(4,270)**	**(4,227)**	**(4,187)**	**(4,150)**	**(4,114)**	**(4,080)**	**(4,049)**	**(4,018)**	**(3,990)**	**(3,963)**	**(3,938)**	**(3,936)**

Appendix 2B - Incremental NPV Analysis between Alternatives 1 & 3 at Energy Price of $80

Incremental NPV analysis (in $k) For 50 Years Ended December 31st, 2076	Total	Period 0	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Capital Expenditures for the upsize	(9,513)	(9,513)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA Tax Shield for the upsize	2,505	0	202	186	171	157	144	133	122	113	104	95	88	81	74	68	63	58	53	49	45	41	38	35	32	30	27
Line Loss Savings for the upsize	25,334	0	308	315	321	328	334	341	348	355	362	369	376	384	392	399	407	416	424	432	441	450	459	468	477	487	497
Incremental Impact to Ratepayers for the upsize	**18,325**	**(9,513)**	**510**	**500**	**492**	**485**	**479**	**474**	**470**	**467**	**465**	**464**	**464**	**464**	**466**	**468**	**470**	**473**	**477**	**481**	**486**	**491**	**497**	**503**	**510**	**517**	**524**
Discount Factor Full Year Discount @ 0.057		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value for the upsize		(9,513)	483	448	417	389	364	341	320	301	284	268	253	240	228	216	206	196	187	179	171	163	157	150	144	138	132
Cumulative Incremental Net Present Value for the upsize	**(1,101)**	**(9,513)**	**(9,030)**	**(8,582)**	**(8,165)**	**(7,777)**	**(7,413)**	**(7,072)**	**(6,753)**	**(6,452)**	**(6,168)**	**(5,900)**	**(5,647)**	**(5,407)**	**(5,179)**	**(4,963)**	**(4,757)**	**(4,561)**	**(4,373)**	**(4,195)**	**(4,024)**	**(3,860)**	**(3,704)**	**(3,554)**	**(3,410)**	**(3,272)**	**(3,140)**

Incremental NPV analysis (in $k) For 50 Years Ended December 31st, 2076	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	Terminal Value
Capital Expenditures for the upsize	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA Tax Shield for the upsize	25	23	21	20	18	17	15	14	13	12	11	10	9	8	8	7	7	6	6	5	5	4	4	4	3	23
Line Loss Savings for the upsize	507	517	527	538	548	559	571	582	594	605	618	630	643	655	669	669	669	669	669	669	669	669	669	669	669	0
Incremental Impact to Ratepayers for the upsize	**532**	**540**	**548**	**557**	**566**	**576**	**586**	**596**	**606**	**617**	**628**	**640**	**652**	**664**	**676**	**676**	**675**	**675**	**674**	**674**	**673**	**673**	**673**	**672**	**672**	**23**
Discount Factor Full Year Discount @ 0.057	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value for the upsize	127	122	118	113	109	105	101	97	93	90	87	84	81	78	75	71	67	63	60	57	54	51	48	45	43	1
Cumulative Incremental Net Present Value for the upsize	**(3,012)**	**(2,890)**	**(2,773)**	**(2,660)**	**(2,551)**	**(2,446)**	**(2,345)**	**(2,248)**	**(2,155)**	**(2,065)**	**(1,978)**	**(1,895)**	**(1,814)**	**(1,736)**	**(1,661)**	**(1,591)**	**(1,524)**	**(1,460)**	**(1,400)**	**(1,344)**	**(1,290)**	**(1,239)**	**(1,191)**	**(1,146)**	**(1,103)**	**(1,101)**

Appendix 2C - Incremental NPV Analysis between Alternatives 1 & 3 at Energy Price of $120, Page 1 of 2

Incremental NPV analysis (in $k)
For 50 Years Ended December 31st, 2076

	Total	Period 0	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Capital Expenditures for the upsize	(9,513)	(9,513)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA Tax Shield for the upsize	2,505	0	202	186	171	157	144	133	122	113	104	95	88	81	74	68	63	58	53	49	45	41	38	35	32	30	27
Line Loss Savings for the upsize	38,001	0	463	472	482	491	501	511	521	532	543	553	564	576	587	599	611	623	636	648	661	675	688	702	716	730	745
Incremental Impact to Ratepayers for the upsize	**30,992**	**(9,513)**	**664**	**658**	**652**	**648**	**646**	**644**	**644**	**644**	**646**	**649**	**652**	**656**	**661**	**667**	**674**	**681**	**689**	**697**	**706**	**716**	**726**	**737**	**748**	**760**	**772**
Discount Factor Full Year Discount @ 0.057		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value for the upsize		(9,513)	629	589	553	520	490	463	438	415	394	374	356	339	324	309	295	282	270	259	248	238	229	220	211	203	195
Cumulative Incremental Net Present Value for the upsize	**2,366**	**(9,513)**	**(8,885)**	**(8,295)**	**(7,742)**	**(7,222)**	**(6,732)**	**(6,269)**	**(5,831)**	**(5,416)**	**(5,022)**	**(4,648)**	**(4,291)**	**(3,952)**	**(3,629)**	**(3,320)**	**(3,025)**	**(2,742)**	**(2,472)**	**(2,213)**	**(1,964)**	**(1,726)**	**(1,497)**	**(1,277)**	**(1,066)**	**(863)**	**(668)**

Incremental NPV analysis (in $k)
For 50 Years Ended December 31st, 2076

	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	Terminal Value
Capital Expenditures for the upsize	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA Tax Shield for the upsize	25	23	21	20	18	17	15	14	13	12	11	10	9	8	8	7	7	6	6	5	5	4	4	4	3	23
Line Loss Savings for the upsize	760	775	791	806	823	839	856	873	890	908	926	945	964	983	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	0
Incremental Impact to Ratepayers for the upsize	**785**	**798**	**812**	**826**	**840**	**856**	**871**	**887**	**903**	**920**	**937**	**955**	**973**	**992**	**1,011**	**1,010**	**1,009**	**1,009**	**1,008**	**1,008**	**1,007**	**1,007**	**1,007**	**1,006**	**1,006**	**23**
Discount Factor Full Year Discount @ 0.057	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value for the upsize	188	181	174	168	161	155	150	144	139	134	129	125	120	116	112	106	100	95	90	85	80	76	72	68	64	1
Cumulative Incremental Net Present Value for the upsize	**(480)**	**(299)**	**(125)**	**42**	**203**	**359**	**509**	**653**	**792**	**927**	**1,056**	**1,181**	**1,301**	**1,417**	**1,529**	**1,635**	**1,735**	**1,830**	**1,919**	**2,004**	**2,084**	**2,160**	**2,232**	**2,300**	**2,364**	**2,366**

Appendix 3A - Incremental NPV Analysis between Alternatives 1 & 4 at Energy Price of $47.30

Incremental NPV analysis (in $k)
For 50 Years Ended December 31st, 2076

	Total	Period 0	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Capital Expenditures for the upsize	(12,545)	(12,545)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA Tax Shield for the upsize	3,303	0	266	245	225	207	191	175	161	148	136	126	116	106	98	90	83	76	70	64	59	55	50	46	42	39	36
Line Loss Savings for the upsize	21,189	0	258	263	269	274	279	285	291	297	303	309	315	321	327	334	341	348	354	362	369	376	384	391	399	407	415
Incremental Impact to Ratepayers for the upsize	**11,947**	**(12,545)**	**524**	**508**	**494**	**481**	**470**	**460**	**452**	**445**	**439**	**434**	**430**	**427**	**425**	**424**	**423**	**424**	**425**	**426**	**428**	**431**	**434**	**438**	**442**	**446**	**451**
Discount Factor Full Year Discount @ 0.057		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value for the upsize		(12,545)	496	455	419	386	357	331	308	287	268	250	235	221	208	196	186	176	167	158	151	143	137	130	125	119	114
Cumulative Incremental Net Present Value for the upsize	**(4,797)**	**(12,545)**	**(12,049)**	**(11,594)**	**(11,175)**	**(10,789)**	**(10,432)**	**(10,101)**	**(9,794)**	**(9,507)**	**(9,240)**	**(8,989)**	**(8,754)**	**(8,533)**	**(8,325)**	**(8,129)**	**(7,944)**	**(7,768)**	**(7,601)**	**(7,443)**	**(7,292)**	**(7,149)**	**(7,012)**	**(6,882)**	**(6,757)**	**(6,638)**	**(6,524)**

Incremental NPV analysis (in $k)
For 50 Years Ended December 31st, 2076

	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	Terminal Value
Capital Expenditures for the upsize	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA Tax Shield for the upsize	33	30	28	26	24	22	20	18	17	16	14	13	12	11	10	9	9	8	7	7	6	6	5	5	4	30
Line Loss Savings for the upsize	424	432	441	450	459	468	477	487	496	506	517	527	537	548	559	559	559	559	559	559	559	559	559	559	559	0
Incremental Impact to Ratepayers for the upsize	**457**	**463**	**469**	**475**	**482**	**490**	**497**	**505**	**513**	**522**	**531**	**540**	**550**	**559**	**569**	**569**	**568**	**567**	**567**	**566**	**565**	**565**	**564**	**564**	**564**	**30**
Discount Factor Full Year Discount @ 0.057	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value for the upsize	109	105	100	96	93	89	86	82	79	76	73	71	68	65	63	60	56	53	50	48	45	43	40	38	36	2
Cumulative Incremental Net Present Value for the upsize	**(6,415)**	**(6,310)**	**(6,209)**	**(6,113)**	**(6,020)**	**(5,931)**	**(5,846)**	**(5,764)**	**(5,684)**	**(5,608)**	**(5,535)**	**(5,465)**	**(5,397)**	**(5,331)**	**(5,268)**	**(5,208)**	**(5,152)**	**(5,099)**	**(5,048)**	**(5,001)**	**(4,956)**	**(4,913)**	**(4,873)**	**(4,835)**	**(4,799)**	**(4,797)**

Appendix 3B - Incremental NPV Analysis between Alternatives 1 & 4 at Energy Price of $80, Page 1 of 2

Incremental NPV analysis (in $k)
For 50 Years Ended December 31st, 2076

	Total	Period 0	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Capital Expenditures for the upsize	(12,545)	(12,545)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA Tax Shield for the upsize	3,303	0	266	245	225	207	191	175	161	148	136	126	116	106	98	90	83	76	70	64	59	55	50	46	42	39	36
Line Loss Savings for the upsize	35,838	0	436	445	454	463	473	482	492	502	512	522	532	543	554	565	576	588	600	612	624	636	649	662	675	689	703
Incremental Impact to Ratepayers for the upsize	**26,596**	**(12,545)**	**702**	**690**	**679**	**670**	**663**	**657**	**653**	**650**	**648**	**647**	**648**	**649**	**652**	**655**	**659**	**664**	**670**	**676**	**683**	**691**	**699**	**708**	**718**	**728**	**738**
Discount Factor Full Year Discount @ 0.057		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value for the upsize		(12,545)	665	618	576	538	504	473	444	419	395	374	354	336	319	303	289	275	263	251	240	230	220	211	203	194	187
Cumulative Incremental Net Present Value for the upsize	**(787)**	**(12,545)**	**(11,880)**	**(11,262)**	**(10,686)**	**(10,148)**	**(9,644)**	**(9,172)**	**(8,727)**	**(8,309)**	**(7,914)**	**(7,540)**	**(7,186)**	**(6,851)**	**(6,532)**	**(6,229)**	**(5,940)**	**(5,665)**	**(5,402)**	**(5,151)**	**(4,911)**	**(4,681)**	**(4,460)**	**(4,249)**	**(4,047)**	**(3,852)**	**(3,666)**

Incremental NPV analysis (in $k)
For 50 Years Ended December 31st, 2076

	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	Terminal Value
Capital Expenditures for the upsize	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA Tax Shield for the upsize	33	30	28	26	24	22	20	18	17	16	14	13	12	11	10	9	9	8	7	7	6	6	5	5	4	30
Line Loss Savings for the upsize	717	731	746	760	776	791	807	823	840	856	874	891	909	927	946	946	946	946	946	946	946	946	946	946	946	0
Incremental Impact to Ratepayers for the upsize	**750**	**761**	**774**	**786**	**799**	**813**	**827**	**842**	**857**	**872**	**888**	**904**	**921**	**938**	**956**	**955**	**954**	**954**	**953**	**952**	**952**	**951**	**951**	**951**	**950**	**30**
Discount Factor Full Year Discount @ 0.057	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value for the upsize	179	172	166	160	153	148	142	137	132	127	123	118	114	110	106	100	95	90	85	80	76	72	68	64	61	2
Cumulative Incremental Net Present Value for the upsize	**(3,486)**	**(3,314)**	**(3,148)**	**(2,989)**	**(2,835)**	**(2,687)**	**(2,545)**	**(2,408)**	**(2,276)**	**(2,149)**	**(2,026)**	**(1,908)**	**(1,794)**	**(1,684)**	**(1,579)**	**(1,478)**	**(1,384)**	**(1,294)**	**(1,209)**	**(1,129)**	**(1,053)**	**(982)**	**(914)**	**(850)**	**(789)**	**(787)**

Appendix 3C - Incremental NPV Analysis between Alternatives 1 & 4 at Energy Price of $120

Incremental NPV analysis (in $k) For 50 Years Ended December 31st, 2076	Total	Period 0	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Capital Expenditures for the upsize	(12,545)	(12,545)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA Tax Shield for the upsize	3,303	0	266	245	225	207	191	175	161	148	136	126	116	106	98	90	83	76	70	64	59	55	50	46	42	39	36
Line Loss Savings for the upsize	53,757	0	654	668	681	695	709	723	738	752	767	783	799	814	831	847	864	882	899	917	936	954	973	993	1,013	1,033	1,054
Incremental Impact to Ratepayers for the upsize	**44,515**	**(12,545)**	**920**	**912**	**906**	**902**	**900**	**898**	**899**	**901**	**904**	**908**	**914**	**921**	**929**	**937**	**947**	**958**	**969**	**982**	**995**	**1,009**	**1,024**	**1,039**	**1,055**	**1,072**	**1,090**
Discount Factor Full Year Discount @ 0.057		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value for the upsize		(12,545)	871	817	768	724	683	646	612	580	551	524	499	476	454	434	415	397	381	365	350	336	322	310	298	286	275
Cumulative Incremental Net Present Value for the upsize	**4,118**	**(12,545)**	**(11,674)**	**(10,856)**	**(10,088)**	**(9,364)**	**(8,681)**	**(8,035)**	**(7,423)**	**(6,843)**	**(6,292)**	**(5,768)**	**(5,269)**	**(4,793)**	**(4,339)**	**(3,905)**	**(3,490)**	**(3,092)**	**(2,712)**	**(2,347)**	**(1,997)**	**(1,661)**	**(1,339)**	**(1,029)**	**(731)**	**(445)**	**(169)**

Incremental NPV analysis (in $k) For 50 Years Ended December 31st, 2076	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	Terminal Value
Capital Expenditures for the upsize	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA Tax Shield for the upsize	33	30	28	26	24	22	20	18	17	16	14	13	12	11	10	9	9	8	7	7	6	6	5	5	4	30
Line Loss Savings for the upsize	1,075	1,096	1,118	1,141	1,164	1,187	1,211	1,235	1,260	1,285	1,310	1,337	1,363	1,391	1,419	1,419	1,419	1,419	1,419	1,419	1,419	1,419	1,419	1,419	1,419	0
Incremental Impact to Ratepayers for the upsize	**1,108**	**1,127**	**1,146**	**1,166**	**1,187**	**1,209**	**1,231**	**1,253**	**1,276**	**1,300**	**1,325**	**1,350**	**1,376**	**1,402**	**1,429**	**1,428**	**1,427**	**1,427**	**1,426**	**1,425**	**1,425**	**1,424**	**1,424**	**1,423**	**1,423**	**30**
Discount Factor Full Year Discount @ 0.057	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value for the upsize	265	255	246	237	228	220	212	204	197	190	183	176	170	164	158	150	142	134	127	120	113	107	102	96	91	2
Cumulative Incremental Net Present Value for the upsize	**96**	**351**	**597**	**833**	**1,061**	**1,281**	**1,493**	**1,697**	**1,893**	**2,083**	**2,266**	**2,442**	**2,612**	**2,776**	**2,935**	**3,084**	**3,226**	**3,360**	**3,487**	**3,607**	**3,720**	**3,827**	**3,929**	**4,025**	**4,116**	**4,118**

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OEB STAFF INTERROGATORY - 05

Reference:

1. Exhibit B-5-1, Page 1
2. Neighbours on the Line Letter, November 16, 2023

Preamble:

In January 2023 Hydro One publicly released a preliminary preferred Project route for review and comment. Hydro One states that during this route development and evaluation period it undertook and completed a detailed review and analysis of the alternative proposed by Kaministiquia community members. All alternative route assessments undertaken by Hydro One determined that the Project's preliminary preferred route, as included in the application, best balances Indigenous culture, values and land use, natural environment, socio-economic environment, and technical and cost considerations.

In its letter dated November 16, 2023, Neighbours on the Line (NOTL), an intervenor in this proceeding, states that through the Environmental Assessment (EA) process, it proposed an alternative route that would save between $90 million to $100 million based on Hydro One's estimates.

Interrogatory:

a) Please confirm if a financial assessment of the alternative route proposed by NOTL was completed. If so, please provide a summary of the analysis and the results. If not, please explain why.

Response:

a) NOTL's November 16, 2023 letter to the OEB describes an apparent "alternative route" which NOTL claims resulted from discussions with Hydro One during the EA process. To be clear, the route described in NOTL's correspondence is new information that has not previously been shared with Hydro One. That said, Hydro One notes that this proposal is described, "to go directly to Dryden via Upsala and Ignace, bypassing Atikokan."

   What NOTL now describes as its proposed "alternate route," is situated "north of Thunder Bay to west of Upsala then northwest past Ignace to follow the existing 230 kV Transmission Line to Dryden[1]". Hydro One confirms it did not perform a 'financial assessment' of the route as this proposal is of little relevance to this proceeding or of consequence to the EA. NOTL's new proposal does not meet the

[1] NOTL's letter to the OEB, dated November 16, 2023, Pg 1.

IESO's system planning requirements that require the Project to connect through the Mackenzie Transformer Station in Atikokan Ontario[2]. By-passing Atikokan, as NOTL describes, does just that (i.e., does not connect to Mackenzie Transformer Station).

The original route alternative proposed by NOTL and considered in the EA process met the IESO's system planning requirements of connecting to Mackenzie Transformer Station in Atikokan. However, this proposal was rejected after an evaluation was completed because it was some 41 km longer – approximately 22% - than Hydro One's preferred route. The increased cost associated to construct this additional distance, along with negative impact to Indigenous and natural environment considerations were a sufficient basis for Hydro One to reject it as a preferred alternative, which would have otherwise led to additional detailed engineering and design costs as part of the routing assessment process.

[2] Exhibit B, Tab 3, Schedule 1, Attachments 5 through Attachment 8, which all reference the need for the line connecting to Mackenzie TS, in Atikokan.

OEB STAFF INTERROGATORY - 06

Reference:

1. Exhibit B-5-1, Page 2

Preamble:

Hydro one evaluated the following conductor sizes, with Alternative 1 as the preferred option:

- Alternative 1 – ACSR 795 kcmil conductor
- Alternative 2 – ACSR 997 kcmil conductor
- Alternative 3 – ACSR 1192 kcmil conductor
- Alternative 4 – ACSR 1443 kcmil conductor

Hydro One states that all alternatives listed above address the supply load need of the Project and provide a reliable supply to customers in the area.

The Project is comprised of two Phases: 1) a double-circuit 230 kV transmission line spanning approximately 190km between Lakehead TS to Mackenzie TS, and 2) a single-circuit 230 kV transmission line spanning approximately 170km between Mackenzie TS to Dryden TS.

Interrogatory:

a) What is the minimum conductor size that would address the supply load need for each phase of the Project?

b) If the minimum conductor size noted in the answer to a) is not the preferred alternative, please explain why.

c) Please explain why these specific conductor sizes were selected as alternatives and not other sizes.

d) Did Hydro One consider the options with different conductor sizes for the Phase 1 and 2 of the Project? Please explain the results of that analysis.

Response:

a) The minimum conductor size that would suitably address the supply load need for each phase of the Project is ACSR 795 kcmil conductor (as suggested as Alternative 1).

b) The minimum conductor size is the preferred alternative.

c) Alternative conductor sizes considered were based on standard conductor sizes used across Hydro One's transmission system, growing progressively larger for 795 kcmil to 1443 kcmil. Non-standard sizes were not considered because it would result in higher capital and operating costs given their non-standardized features as compared to the existing design of Hydro One's transmission system. Other larger standardized conductor sizes were not selected as, again, the costs using these conductors would result in higher costs, as compared to the preferred alternative, without any incremental offsetting benefits.

d) No, the analysis of alternatives utilized the same Hydro One standard conductor sizes for both Phase 1 and Phase 2.

OEB STAFF INTERROGATORY - 07

Reference:

1. Exhibit B-7-1, Pages 1-4 and 7-8
2. EB-2022-0140, Exhibit B-7-1, Pages 1-2
3. EB-2017-0182, Exhibit B-9-1, Page 1

Preamble:

OEB staff have developed the following table comparing the Project's contingency estimates to recent Leave to Construct applications with significant budgets. The Project's contingency estimates have been developed using the first reference noted above, while the contingency estimates for the comparator projects have been developed based on the second and third references.

Table 1 - Contingency Cost Comparison

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

At the first reference, Hydro One indicates that its cost estimate includes an allowance for contingencies in recognition of risks associated with estimating costs. The top project risks noted by Hydro One include a) land acquisition, b) engagement and consultation, and c) approvals, permits and authorizations.

Approvals, permits and authorizations involve risk of delay when obtaining the necessary approvals, permits and authorizations, such as the Environmental Assessment (EA), S.92 Leave to Construct and archaeology.

Hydro One also provides cost contingencies that have not been included, due to the unlikelihood or uncertainty of occurrence.

Interrogatory:

a) Please describe in detail the process followed by Hydro One to develop the contingency estimates for the Project. Please also provide a detailed breakdown of the contingency estimates for line costs and station costs.

b) Based on the analysis noted by OEB staff in the Preamble, it appears that the contingency estimates for the Project are higher, on a percentage basis, relative to the

noted comparators. Given this analysis, please explain why the Project's contingency estimates are appropriate.

c) To what extent does the risk associated with the land acquisition process increase the overall project costs.

d) Besides the top three risks outlined in the application, please provide other project risks considered as contributing factors to the total contingency and a brief explanation of each risk.
   i. Please provide an indication of the relative importance of each of the risks towards the estimated contingency cost.

e) Please explain the likelihood of risks occurring for the cost contingencies that have not been included and estimate the potential impact of such events on cost and the in-service date. Please also explain steps that Hydro One will take to mitigate these risks.

Response:

Preface:
Hydro One notes in Table 1 (above) of the interrogatory question, the East-West Tie Station costs contingency was excluded. Station cost contingency, based upon the s.92 filing in EB-2017-0194 are shown below.

Table 1 - Contingency Cost Comparison

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

a) Hydro One followed an industry established best practices methodology in developing the contingency utilizing a risk management model. The components of the risk management model are: obtain inputs from project team stakeholders; assess complexity to determine level of complexity and subsequent level of structured analysis required; plan a project specific risk model defining project objectives, risk thresholds, roles and responsibilities, and how the remaining risk processes will be implemented; identify all credible threats to the achievement of project objectives and if any opportunities exist that may possibly promote project objectives; analyze the likelihood of occurrence, degree of impact on occurrence, and the prioritization of identified risks slated for further analysis, respond by developing a strategy to treat the

risk (i.e. accept, avoid, mitigate, transfer); and execute and control by implementing the planned strategy with continued monitoring and control to confirm effectiveness, make adjustments if needed, and ensure the planned results are achieved.

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

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

Table 2 - Probabilistic Contingency Allocation Summary

($M's)	Phase 1	Phase 2	Total
Line Contingency Allocation	57.2	42.7	99.9
Station Contingency Allocation	17.4	6.3	23.7
Total Contingency Allocation	74.6	49.0	123.6

b) The Project's contingency estimates account for a broad range of risks that stem from a complex multi-year project. The contingency considers many risks related to market volatility, commodity prices, availability of resources, production escalation costs and labor rate escalation that will fluctuate over the execution of this multi-year project. These risks factors are also more significant than was typical prior to COVID-19 which was not a factor in many of the comparator projects that had estimates completed prior to COVID-19.

c) The Land Acquisition risk identified in Exhibit B, Tab 7, Schedule 1 is a compilation of multiple discrete related risks, each with individualized residual cost and likelihood of occurrence variables. As described in response to part a) above, the contingency amount is calculated based on probabilistic assessment of risk occurrence and is not an exact amount intended to fully fund all Project construction risks that may potentially be incurred. As a result, an explicit costing of the land acquisition risks on the overall project costs is not available.

d) Other project risks considered as contributing factors to the total contingency are presented in Table 3 (in order of importance). This includes risks for both lines and stations. As part of a future rate hearing, Hydro One will disclose actual utilization of the contingency for risks that materialized for review by the Ontario Energy Board.

Table 3 - Project Risk Summary

Risk Category	Risk Name	Description of impact to cost
1	Land Acquisition	Expropriation, Compensation for Business Disruption/Loss, land cost, Injurious Affection, option agreements, market value top-up, early access agreement delays, mine and mining claims interactions, voluntary buyouts, mandatory buyouts
2	Engagement and Consultation	Extent of involvement by communities in project. Availability of community's staff, and unknown expectations may have project impacts. Indigenous Knowledge, review timelines, issues management.
3	Permits, Approvals, Authorizations	Delays in approvals (i.e., S92, EA, permits, authorizations etc) may lead to downstream impacts and delays; request for additional consultation; request for additional field studies; prolonged review cycles. Regulatory responses times slow, staffing changes, timeliness reviews to provide inputs on studies, reports and key documentation could cause schedule delays and setbacks. Certain permits required in advance of construction can take significant time and budget (e.g., Species at risk (SAR) permits). Inability to acquire in time for construction could delay construction start in certain areas.
4	Material Supply	Predictable delay in long lead items, increased demand, raw commodity price escalation may impact costs and/or schedule.
5	Routing	Micro-routing adjustments, technical solutioning
6	Environmental Constraints	Timing windows, unknown conditions of approvals, imposed mitigation requirements and/or limitations on seasonal timing / execution methods of completing certain discrete components of scope.
7	Archaeology	Extent of, potential for risks to construction if Stage 3/4 required.
8	Coordination with Sustainment projects	Different crews from internal and external contractors performing sustainment work in stations may lead to Health and Safety issues due to congested site and security issues which may impact the schedule and cost.

9	Assertions	Assertions by Indigenous communities not identified by the Crown on the Duty to Consult
10	Subsurface Issues	Unknown soil contamination, disposal requirements
11	Schedule	Aggressive schedule may require acceleration as driven by project need. May impact costs.
12	Change of scope	Regulatory requirements, technical constraints may change scope.
13	Political landscape	Change in leadership could cause delays
14	Owner driven delays	Due to delay in items in Hydro One's responsibility this could lead to delay in the overall project leading to claims from contractors
15	Outages	Many reasons could lead to cancelling a scheduled outage which will cause disruption and delay to project schedule
16	Human Resource Availability	Limited access to skilled labour, professional services may cause delays and cost impacts.
17	Project opposition	Potential opposition by communities, political, stakeholder, landowner, rights holders and interested parties may cause schedule and cost impacts.
18	Extreme Weather	Extreme weather may have implications on project, access to labour, access to markets (i.e. Turkey Earthquake)
19	Change in regulatory landscape	Change in legislation, guidelines or permits. Change in processes.
20	Pandemic	Pandemic restrictions coming into force, outbreak

e) As per Hydro One's description in Exhibit B, Tab 1, Schedule 7, p. 8, cost contingencies not contributing to the allowances included for this Project are due to the unlikelihood (or uncertainty) of occurrence. Those items include labour disputes, safety or environmental incidents, non-predictable significant changes in costs of materials, and other unforeseen and potentially significant event/occurrence risks outside the control of Hydro One, that may occur after the estimate preparation was completed.

The likelihood of these risks occurring and impacting costs for the Project is considered low and as a result, a cost value was not included for them in the Project's contingency. These risks are actively mitigated through continued monitoring and updating of the Project's risk matrix. The EPC fixed price contracts also act as further mitigation of these risks.

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OEB STAFF INTERROGATORY - 08

Reference:

1. Exhibit B-7-1, Page 10

Preamble:

Hydro One states that the price of essential commodities has a significant impact on project costs. Equipment purchased to construct transmission lines (e.g., steel towers, conductors and miscellaneous hardware) is heavily impacted by certain raw material indices. Essential commodities such as copper, aluminum and steel have undergone price increases and supply shortages.

Hydro One specifically notes that "from January 2021 to January 2022, the price of copper has increased by 27.1%, aluminum has increased by 41.6% and steel has increased by 111.6%".

Interrogatory:

a) Please provide a table detailing how the prices of copper, aluminum, steel and any other essential commodities have changed from January 2021 to January 2023. Please show changes in prices on a quarterly basis.

b) Please estimate the impact of the increase in commodity prices on the total Project cost.

Response:

a) As an indication of how the prices of essential commodities have changed on a quarterly basis from January 2021 to January 2023 please refer to Table 1 below. For further context please refer to Exhibit I, Tab 01, Schedule 11 a).

Table 1 - Price index for Copper, Aluminum and Steel

	Currency	Unit of Measure	Jan 2021	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Jan 2023
Copper	US Cents	lb	351	409	468	436	428	444	430	352	373	381
Aluminum	US Cents	lb	90	100	109	123	120	156	128	107	108	108
Steel	US Dollar	cwt	43	54	70	87	91	90	95	87	75	73

b) As stated in Exhibit B, Tab 7, Schedule 1, and as presented in Table 1 above, Hydro One has observed significant cost fluctuations in raw materials between January 2021 and January 2023. As explained in Exhibit I, Tab 1, Schedule 11, part a), these raw material costs have influenced this Project's equipment and material costs directly. As

raw material costs stabilized, manufacturing costs continued an upward trend because the demand for the output exceeded the production capacity. This, combined with a highly competitive labour market continued to drive costs higher. By way of an example, the Request for Proposal (to select an organisation for the lines EPC) was held in Q1/Q2 2022, resulting in the EPC developing their pricing during this period. The EPC contract, containing a fixed price contract, was secured in Q4 2022. The fixed price EPC contract mitigates further price fluctuations pertaining to the EPC scope of work.

OEB STAFF INTERROGATORY - 09

Reference:

1. Exhibit B-7-1, Page 4 and 15

Preamble:

Hydro One states that the Project lines and station cost estimates are based on a fixed price EPC contract.

Interrogatory:

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

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

c) Please update Tables 7, 8 and 9 at Exhibit B, Tab 7, Schedule 1 to reflect the inflation adjustment factors that include the latest OEB's annual inflation parameters for 2024.

Response:

a) A copy of this response has been filed confidentially with the OEB in accordance with its Practice Direction on Confidential Filings.

b) The EPC contracts, excluding interest and overhead, are forecast to represent approximately [REDACTED] of the direct costs or [REDACTED] of total project costs including interest and overheads. Furthermore, other functions normally performed internally by Hydro One are also outsourced but not to the EPC vendor, such as owner's engineering, which represent approximately an additional [REDACTED] of direct costs and slightly under [REDACTED] of total project costs including interest and overheads. Please see Exhibit I, Tab 1, Schedule 22, part b) for further details.

c) The rate used in the prefiled evidence Tables 7, 8 and 9 of Exhibit B, Tab 7, Schedule 1, are based on the OEB-issued 2023 inflation factor of 3.8% for 2023 and the years beyond. Hydro One has updated Tables 7, 8 and 9 of Exhibit B, Tab 7, Schedule 1, to include the latest OEB's annual inflation parameters for 2024 (i.e., 5.4%[1]). The only difference between the three tables, as referenced in the question above, and the tables provided below, labeled as Table 7, 8 and 9 respectively (for ease of comparability), is that for the year 2024 and beyond the OEB-issued 2024 transmission inflation factor of 5.4% is used.

[1] OEBltr_2024 inflation_updates_20230629

1 **Table 7 - Costs of Comparable Lines Projects - Lines**

Project (Costs are in $M's)	Hawthorne x Merivale Conductor Upgrade	South Nepean DETL Estimate South Nepean Trans Reinforcement	WATR Ingersoll x Karn x Woodstock	Upper Canada Transmission Inc. East-West Tie Line	Waasigan Transmission Lines Project
Circuit Nomenclature	M30A/M31A	S7M/E34M	M32W/M31W + K12/K7	M37L/M38L	A30L/A31L (Phase 1) D32A (Phase 2)
Voltage	230 kV	230 kV	230 kV	230 kV	230 kV
Structure Type	Steel Lattice	Steel Lattice (10%) Steel Pole (73%), BPE/BPD (17%)	Steel Lattice (83%) Steel Pole (10%), BPE/BPD (7%)	Steel Lattice	Steel Lattice Towers
Circuit Type	Double	Double	Double	Double	Double/Single[2]
Conductor	1192 kcmil	997 kcmil	1443 kcmil	1192 kcmil	795 kcmil
Location	Eastern Ontario, Rural	Eastern Ontario, Rural	Southern Ontario, Rural	Northern Ontario, Rural	Northern Ontario, Rural
In-Service Year	June 2023	November 2021	March 2012	2022	2025/2027
Estimate/Actual	Actual	Actual	Actual	Estimate[3]	Estimated
Cost ($M's)	$39.4	$51.3	$35.6	$935.9	$992.7
Less;					
Real Estate	0.9	2.2	0.5	23.3	62.5[4]
Bypass	N/A	1.4	4.3	N/A	N/A
Micropiles	N/A	6.7	N/A	N/A	N/A
Adjusted Costs	38.5	40.9	30.8	912.6	934.3
Escalation Adjustment[5]	7.4	10.1	15.7	224.8	N/A
Escalated Total Project Cost	45.9	51.0	46.5	1,137.4	N/A
Length	12.0	12.2	13.6	450	360
Cost per Km	**3.8**	**4.2**	**3.4**	**2.5**	**2.6**

[2] Double circuit length is 190km, single circuit length is 170km.
[3] Per report from Upper Canada Transmission for the *East-West Tie Line Quarterly Construction Progress Report* dated October 21, 2022, (Pg. 15). Docket EB-2017-0182.
[4] This amount includes the direct real estate costs identified in Table 1 ($69,683) plus contingency carried for expropriation, interest and overhead.
[5] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

1 **Table 8 - Costs of Comparable Station Projects (Phase 1)**

Project (Cost $M's)	Wawa TS	Marathon TS	Lakehead TS	Lakehead TS Phase 1	Mackenzie TS Phase 1
Technical	(6) 230kV Circuit Breakers, (19) Disconnect Switches, (5) CVTs, AC/DC Station Service, (1) P&C Building	(12) 230kV Circuit Breakers, (2) Reactors, (36) Disconnect Switches, (8) CVTs, AC/DC Station Service, (1) P&C Building	(8) 230kV Circuit Breakers, (1) Reactors, (20) Disconnect Switches, (8) CVTs, AC/DC Station Service, (1) P&C Building	(4) 230kV Circuit Breakers, (1) Reactors, (10) Disconnect Switches, (3) CVTs, AC/DC Station Service, (1) P&C Building	(5) 230kV Circuit Breakers, (2) Reactors, (14) Disconnect Switches, (6) CVTs, AC/DC Station Service, (1) P&C Building
Project Surroundings	Northern Ontario, Rural	Northern Ontario, Rural	Northern Ontario, Rural	Northern Ontario, Rural	Northern Ontario, Rural
In-Service Date	March 2022	March 2022	March 2022	December 2025	December 2025
Estimate or Actual	Actual	Actual	Actual	Estimate	Estimate
OEB-Approved Cost Estimate	Combined total of $157.3			-	-
Total Project Cost	$51.7 M[6]	$71.8	$57.7	$66.3	$88.7
Less Adjustments					
Less: Land Cost	N/A	N/A	N/A	N/A	N/A
Less: Line Entrance	N/A	N/A	N/A	3.7	0.8
Adjusted cost	**$51.7**	**$71.8**	**$57.7**	**$62.6**	**$87.9**
Escalation Adjustment[7]	**$9.0**	**$12.5**	**$10.1**	**N/A**	**N/A**
Total Comparable Project Costs	**$60.7**	**$84.3**	**$67.8**	**$62.6**	**$87.9**

[6] Together the three EWT Project stations total to Hydro One's, East-West Tie Station Project – EB-2017-0194 - Quarterly Report, Period Ending March 31, 2022, and dated June 21, 2022, of $181.2M.

[7] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

1 **Table 9 - Costs of Comparable Station Projects (Phase 2)**

Project	Holland TS	Beach TS	Mackenzie TS Phase 2	Dryden TS Phase 2
Technical	(2) 230kV Circuit Breakers, (4) Disconnect Switches. (6) Line disconnect switches, (3) CVTs, AC/DC Service Station, P&C Building	(2) 230kV Breakers, (4) Disconnect Switches, (2) Line Disconnect Switches, AC/DC Station Service,	(1) 230lV Circuit Breaker, (2) Disconnect Switches,(1) Line Disconnect Switch, (1) CVT	(2) 230kV Circuit Breakers, (4) Disconnect Switches, (1) Line Disconnect Switch, (3) CVTs, AC/DC Station Service, 230kV Yard Expansion, Space Provision for (1) 40Mvar Reactor and components
Project Surroundings	Central Ontario, Rural	Southern Ontario, Rural	Northern Ontario, Rural	Northern Ontario, Rural
In-Service Date	December 2017	June 2016	December 2027	December 2027
Estimate or Actual	Actual	Actual	Estimate	Estimate
OEB-Approved Cost Estimate	N/A[8]	N/A[9]	-	-
Total Project Cost	$26.8	$21.5	$15.1	$36.2
Less Adjustments				
Less: Land Cost	N/A	N/A	N/A	N/A
Less: Line Entrance	N/A	N/A	1.2	0.0
Adjusted cost	**$26.8**	**$21.5**	**$14.0**	**$36.2**
Escalation Adjustment[10]	**$11.3**	**$10.0**	**N/A**	**N/A**
Total Comparable Project Costs	**$38.1**	**$31.5**	**$14.0**	**$36.2**

[8] This project was encompassed within a previous Hydro One revenue requirement application. The project was not subject to leave to construct approval by the OEB. Therefore, the specific investment does not have a discrete OEB approval to appropriately reference for the purposes of this comparison.
[9] This project was encompassed within a previous Hydro One revenue requirement application. The project was not subject to leave to construct approval by the OEB. Therefore, the specific investment does not have a discrete OEB approval to appropriately reference for the purposes of this comparison.
[10] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

OEB STAFF INTERROGATORY - 10

Reference:

1. Exhibit B-7-1, Pages 12-15

Preamble:

For costs of comparable station projects, Hydro One states that the major differences contributing to the price variation of the station projects include procurement, execution methodology, and project scope.

For execution methodology, Hydro One states that the comparative station projects were executed where design, procurement and construction were undertaken by Hydro One and for this Project, the fixed price EPC execution methodology has been selected to best define and manage project scope.

Interrogatory:

a) Please explain in further detail the execution methodology used for these comparative projects compared to the fixed price EPC methodology used for the Waasigan project in terms of costs and effectiveness of the project delivery.

b) OEB staff notes that the cost for Phase 2 Mackenzie TS is much lower than Dryden TS (table 9). Please provide reasons for the substantial difference in cost.

Response:

a) The comparative projects were executed with design, procurement and construction undertaken by Hydro One, whereas for Waasigan the design, procurement and construction is being undertaken by an EPC contractor.

   The execution methodology was selected based on how best to execute the Project scope in consideration of the availability of either in-house or contracted resources to meet the Project's schedule and cost requirement. The Waasigan Project execution methodology was chosen as the preferred option based on how best to allocate the Project's risks resulting in increased cost predictability versus the comparative projects execution methodology that most likely would have resulted in more cost volatility.

b) Table 9 in Exhibit B, Tab 7, Schedule 1, includes a comparison of the technical aspects of both Mackenzie TS and Dryden TS and can be used to compare the major equipment requirements of both stations for Phase 2 of the Project. From purely a technical perspective Dryden TS requires more equipment (i.e., circuit breakers, disconnect switches) which results in added costs at Dryden TS. There is also

additional work scope required at Dryden TS that is not required at Mackenzie TS in Phase 2, such as the AC station service upgrade and bus modification work.

In addition, there are efficiencies realized at Mackenzie TS through the overlap of scope between Phase 1 and Phase 2. As a result, these efficiencies are shared between both Phases of the Project lowering the cost of both phases at Mackenzie TS.

OEB STAFF INTERROGATORY - 11

Reference:

1. Exhibit B-7-1, Pages 12-15

Preamble:

When considering the cost per km ratio for all other transmission line costs in Table 7 in the reference, Hydro One states that the comparable projects demonstrate that the estimate for the Project is within a reasonable range to that of comparable transmission line works. However, there are some primary factors contributing to, in some instances, a higher project cost which are Procurement Costs and Engagement and Consultation.

For Engagement and Consultation, Hydro One States that a significant difference between this Project and the comparators is the magnitude of engagement and consultation required both on the development and execution of the Project.

Hydro One states that the Project required undertaking a multi-year comprehensive Environmental Assessment and consultation with 21 Indigenous communities and organizations. Engagement has been extensive while also having to adapt throughout the process to the restrictions of COVID-19.

Interrogatory:

a) Please explain in detail the impact of the magnitude of procurement costs and engagement and consultation on total Project cost compared to other projects?

b) Please provide a cost breakdown for procurement and engagement and consultations.

c) OEB staff notes that similar to the Waasigan Project, in the East West Tie Line project[1], NextBridge stated that it engaged eighteen First Nations and Métis communities. The East West Tie Line project included a First Nation partnership with Bamkushwada Limited Partnership which allowed an equity interest. Please explain if there are material differences between the consultation work for the Waasigan Project and the East West Tie Line project.

d) OEB staff notes that execution methodology was one of the factors noted in the application for contributing to the price variation for the station costs. Please explain why this factor was not applicable to the analysis for comparing line cost amongst the comparator projects and the Waasigan Project.

[1] EB-2017-0182, Exhibit H, Tab 1, Schedule 1, p. 1.

Response:

a) Hydro One has generally observed year over year increases in raw materials (i.e., aluminum, steel, copper), and equipment (i.e., breakers, reactors, transformers) procurement. Although significant cost fluctuations occurred during COVID-19 that are now stabilizing, Hydro One is now experiencing escalation costs in manufacturing that are driving costs upward. Escalations in manufacturing costs are driven by raw material price increases, more demand than production time and a highly competitive labour market that is driving labour costs higher. These factors drive overall procurement costs to be higher and contribute to higher risk allocations. Please see response to Exhibit I, Tab 1, Schedule 8 parts a) and b). For the Project, procurement of major equipment, materials and labour is the accountability of the EPC.

Factors that affect engagement and consultation costs on a project include: the requirement and extent of the government of Canada's delegation of the procedural aspects of the Crown's Duty to Consult where established or asserted Aboriginal and Treaty rights could be impacted, the number of interested parties, the number of interested or impacted landowners and residents, the number of interested non-Indigenous communities and number of other interested stakeholders in the project.

The above factors are directly influenced by the linear nature and length of the Project (approximately 360km). Hydro One is engaging with 21 Indigenous communities, First Nations and organizations, 4 federal agencies, 17 provincial agencies, 8 municipalities, 569 stakeholders, interest groups and interested members of the public. Engagement and consultation on the Project started in 2019 and is ongoing. All these efforts contribute to project costs.

Comparing the Project to the Hawthorne x Merrivale Project, in the latter engagement and consultation began in Q4 2019 and in-servicing was in Q2 2023. There was no Duty to Consult requirement (although 3 Indigenous communities were engaged on the project) and there were fewer interested parties (e.g. 2 federal agencies, 5 provincial agencies and 1 municipality). As a further comparison, the Power South Nepean project began engagement and consultation in Q2 2017 and was placed in-service in 2021, had a Duty to Consult requirement with 2 Indigenous communities and consulted 10 federal agencies, 9 provincial agencies, 1 municipality and 46 stakeholders and interest groups.

b) Procurement cost of materials for the Project is estimated at $268.7M as disclosed in Tables 2 to 5 in Exhibit B, Tab 7, Schedule 1.

Engagement and consultation on the Waasigan project has been ongoing since 2019 with the commencement of the environmental assessment. As requested in a letter

dated May 5, 2020, the OEB requested that Hydro One prepare Semi-Annual Reports[2] to the OEB that update on the overall Project progress, cost, development work schedule, risks and issue log. As these Semi-Annual Reports were tied to the development activities of the project alone, and as development activities have a significant component of consultation required, consultation costs were reported discretely. As part of those Semi-Annual Reports Hydro One has reported a budget of $41M for consultation in the development of the Project that includes Environmental Assessment, Indigenous Consultation and Other Consultation. In addition to these costs, the Project cost presented in Exhibit B, Tab 7, Schedule 1 include engagement and consultation during the execution phase. The total engagement and consultation costs thus, comprise of the combined activities associated with engaging Indigenous communities, stakeholders, landowners, members of the public and other interested persons to fulfill the requirements of the Environmental Assessment Act, permitting, procedural aspects of the Crown's duty to consult as well as, to provide ongoing updates on the project outside of these requirements. The resultant aggregate cost estimate for engagement and consultation for the Project is $125M, excluding interest, overhead and contingency.

c) The East-West Tie project was undertaken by Upper Canada Transmission 2 Inc., a party unrelated to Hydro One. Hydro One has no way of assessing whether, or not, material differences existed between the consultation work for the Waasigan Project and the East West Tie Line project.

Hydro One respects the Treaty, Aboriginal and Inherent rights of Indigenous peoples, and respects their laws, customs, and protocols associated with their spiritual and land rights. Waasigan is within the traditional territories of the Treaty #3 and Robinson-Superior First Nations and traverses the Northwestern Ontario Métis Community and Northern Lake Superior Métis Community. Indigenous peoples practice their Treaty, Aboriginal and Inherent rights, including harvesting rights, on these lands. Hydro One understands that individual Indigenous communities are independent Nations and have expressed unique relationships, jurisdictions, responsibilities, and requirements. as it pertains to land rights.

The Crown has a Duty to Consult, and where appropriate, accommodate Indigenous peoples whenever a Crown decision or activity could impact established or asserted Aboriginal and Treaty rights. The Ministry of Energy (formerly the Ministry of Energy, Northern Development and Mines) delegated the procedural aspects of the Crown's Duty to Consult to Hydro One via a letter dated October 25, 2018 and a follow-up letter dated April 15, 2020. The Ministry of Energy determined Hydro One's proposed Project

[2] See EB-2019-0151

may have the potential to affect First Nation and Métis communities who hold or claim Aboriginal or Treaty Rights protected under Section 35 of Canada's Constitution Act,1982. Hydro One entered into a Crown Delegation MOU, which identifies Crown responsibilities, Hydro One responsibilities, record keeping and information sharing requirements, and an Indigenous Consultation Plan requirement. Hydro One worked with Indigenous Communities to develop a Consultation Plan which identifies its commitments and activities for Indigenous engagement on the Project. Fundamental to the plan is the need for meaningful engagement and relationships with the individual Indigenous communities, to understand and address any concerns over impacts to Section 35 rights, and so that Indigenous peoples can share in the benefits from the Project.

The Project will bring both short term and long-term employment, training, and business opportunities to the region. This includes opportunities for both Indigenous and non-Indigenous communities and businesses to benefit from the construction, operation, and maintenance of the Project. Hydro One is collaborating with Indigenous communities in the region to understand their interests and aspirations in the future of Ontario's electricity grid. The Project is being constructed in partnership with nine First Nations in the region, who will have the opportunity to invest in a 50 per cent equity stake in the transmission line component of the Project. Through an industry-leading partnership, the Project will provide innovative and lasting benefits to Indigenous communities in procurement, employment, economic benefits and investment opportunities.

d) The listings in Exhibit B, Tab 7, Schedule 1 that were provided for both lines and stations of contributing factors to compare projects was intended to be a listing of leading factors specific to each line's and/or station's project scope. It is not an exhaustive list and not meant to suggest that the absence of a factor is 'not applicable'.

For both lines and stations, the execution methodologies are the responsibility of the EPC. The cost estimates for both lines and stations reflect current market-tested EPC pricing to deliver both these project scopes including corresponding risk premiums that are transferred to the EPC contractor through the EPC contracts. Execution methodology is listed specifically for stations as there are bespoke risks associated with the stations scope being transferred to the EPC contractor that are not applicable to the lines. For example, as listed in Exhibit I, Tab 1, Schedule 7 there is a risk category associated with 'Coordination with Sustainment Projects' (shown as item 8) that will require coordination of different crews from internal and external contractors performing sustainment and Project work in stations in tandem to one another.

OEB STAFF INTERROGATORY - 12

Reference:

a) Exhibit B-7-1, Page 11
b) East-West Tie Quarterly Progress Report, January 20, 2023
c) East-West Tie Quarterly Progress Report, October 21, 2023

Preamble:

Hydro One compared the estimated costs of the line portion of the Project with four comparators, including Upper Canada Transmission Inc.'s East-West Tie Line. Hydro One states that the cost estimate of $935.9 million for the East-West Tie Line was obtained from Upper Canada Transmission's East-West Tie Line Quarterly Construction Progress Report (Report) dated January 20, 2023.

OEB staff notes that the $935.9 million is referenced in the October 21, 2022 report rather than the January 20, 2023 report. OEB staff notes that on page 15 of the October 21, 2022 Report, $111.6 million, representing 11.9% of the total project cost, is allocated to costs incurred due to Covid-19. This Report states that the Covid-19 costs incurred for the East-West Tie Line include hard costs (i.e., personal protective equipment, safety personnel and security, cleaning, testing equipment, and other costs) and productivity losses (i.e., lost time from unplanned Covid-19 related tasks, social distancing, staggering shifts, etc.).

Interrogatory:

a) Please confirm the date of the Upper Canada Transmission's East-West Tie Line Quarterly Construction Progress Report and the exact page number where the $935.9 million cost estimate of the East-West Tie Line is noted.

b) Please confirm if Hydro One anticipates incurring Covid-19 costs similar to those referenced in Upper Canada Transmission's October 21, 2023 East-West Tie Line Quarterly Construction Progress Report (i.e., Covid-19 hard costs and productivity loss).
   i. If yes, please explain the Covid-19-related costs Hydro One anticipates incurring.
   ii. If no, please explain if it is appropriate to adjust the estimated East-West Tie Line project cost to remove the $111.6 million in Covid-19-related costs when completing the cost per unit km analysis.

c) Please recalculate the cost per unit km for the line portion of the East-West Tie Line project without the $111.6 million in Covid-19-related costs. Please provide the supporting calculations.

Response:

a) Hydro One confirms the $935.9M was sourced from the East-West Tie Quarterly Progress Report, dated October 21, 2022, on page 15 of that report.

b) Hydro One does not anticipate incurring Covid-19 costs similar to those referenced in Upper Canada Transmission 2's October 21, 2022, East-West Tie Line Quarterly Construction Progress Report**.**

Any adjustments made to construction costs should be contemplated based on the rationale for comparison. The EWT **total actual costs,** as filed in Upper Canada Transmission 2 Inc.'s recent revenue requirement application (EB-2023-0298) should be the starting point when using that Project to compare to any future similar transmission line projects. Please refer to response in part c) below for further information.

c) As requested, the calculation for the cost per unit km for the line portion of the East-West Tie Line project without the $111.6 million in Covid-19-related costs is provided in Table 1 below.

Table 1 - Upper Canada Transmission 2 - East-West Tie Line

End Period	Cost ($M)	Months Elapsed	Inflation Rate (%)	Cost Escalation ($M)
June 30, 2022	801.00[1]			
Year-end 2022	811.01	6	2.50%	10.01
Year-end 2023	841.83	12	3.80%	30.82
Year-end 2024	887.29	12	5.40%[2]	45.46
Year-end 2025	935.20	12	5.40%	47.91
Year-end 2026	998.33	12	5.40%	63.13
			Subtotal	***197.33***
Opening Cost ($M)	801.0	*A*		
Inflation Increase $M)	197.3	*B*		
Closing Cost ($M)	**998.3**	*C = A+B*		
Line Length (km)	450	*D*		
Unit Cost ($M / km)	2.2	*E = C/D*		

[1] This is the total project cost of the East-West Tie Line from the Quarterly Progress Report (dated October 21, 2022) of $935.9 million less the adjustment for real estate of $23.3 million (as per Exhibit B, Tab 7, Schedule 1, Table 7), less the $111.6 million in Covid-19 related costs.
[2] 2024 inflation rate and beyond have been updated to use the OEB's 2024 transmission inflation factor per OEBltr_2024 inflation_updates_20230629

Note that the calculations shown in Table 1 above do not address the actual incurred costs spent to complete the EWT Project, or the costs which Upper Canada Transmission 2, Inc. is seeking to recover in rates as per Docket EB-2023-0298. Both values are relevant to the unit cost calculation requested in this Interrogatory.

The above Table 1 analysis is provided as a means of responding to OEB Staff's specific question to provide the math requested. Upper Canada Transmission 2 Inc.'s recently filed revenue requirement application for the East West Tie transmission line project (i.e., Docket EB-2023-0298) states that total EWT Project "Actual Incurred Costs" was $1,029.3 million. Table Ex A.1, from that application, outlines the total cost base Upper Canada Transmission 2 Inc., is seeking to recover via ratepayers, titled 'Costs for Rate Recovery', which includes the rate base approved in EB-2020-0150, of $773.8 million, and additional Covid costs (direct and indirect) totaling $111.6 million currently recorded in its COVID - 19 Variance Account, and amounts totaling $48.7 million currently recorded in its Construction Cost Variance Account ("CCVA")[3]. The total amount of construction incurred and seeking rate recovery is shown in EB-2023-0298, Table Ex A.1, and extracted below.

Table Ex A.1

Approved Budget vs Actual Incurred Construction Costs

Description	Approved Budget Amount	Actual Incurred Costs	Costs for Rate Recovery
Total Construction, Development, & Phase Shift[5]	**773,769,745**	**773,770,132**	**773,770,132**
Cost Overruns			
Accumulated Actual Cost Overruns		255,500,000	
Partial overrun allocations made to:			
CCVA			48,687,137
COVID Direct Cost Variances			22,687,695
COVID Indirect Cost Variances			89,014,103
Subtotal Cost Overruns	**0**	**255,500,000**	**160,388,935**
Total Construction Costs	**$773,769,745**	**$1,029,270,132**	**$934,159,067**

To demonstrate the unit costs associated with the EWT's total actual costs, and costs for rate recovery, Hydro One has provided the following two tables, Table 2 and Table 3 respectively.

For comparative purposes, the results show:

- the total cost of construction of $1,029.3 million equates to an equivalent unit cost of $2.8M per km, and

[3] EWT CCVA costs are described in detail in EB-2023-0298, Exhibit D-1.

- the cost for rate recovery of $934.2 million equates to an equivalent unit cost of $2.5M per km.

The equivalent unit cost for the Waasigan Transmission Lines Project is $2.6M per km, as documented in Exhibit B, Tab 7, Schedule 1, Table 7, and is within the range of the EWT cost per km as presented in Table 1 and Table 2.

Table 2 - East-West Tie Line – Total Actual Costs Incurred

End Period	Cost ($M)	Months Elapsed	Inflation Rate (%)	Cost Escalation ($M)
June 30, 2022	998.81[4]			
Year-end 2022	1,011.30	6	2.50%	12.49
Year-end 2023	1,049.73	12	3.80%	38.43
Year-end 2024	1,106.41	12	5.40%	56.69
Year-end 2025	1,166.16	12	5.40%	59.75
Year-end 2026	1,244.88	12	5.40%	78.72
			Subtotal	***246.06***
Opening Cost ($M)	998.8	*A*		
Inflation Increase $M)	246.1	*B*		
Closing Cost ($M)	**1,244.9**	*C = A+B*		
Line Length (km)	450	*D*		
Unit Cost ($M / km)	2.8	*E = C/D*		

[4] This is the total actual cost incurred for the East-West Tie Line as documented in Docket EB-2023-0298, Table Ex.A.1 of $1,029.3 million less the adjustment for real estate $23.3 million less adjustment for real estate pertaining to the cost overrun allocations (i.e. $2.17 million as per Table Ex.D.14 - CCVA and $4.98 million as per Table Ex.C.9 - Account 1509 for Covid-19 related costs).

Table 3 - East-West Tie Line – Total Costs for Rate Recovery

End Period	Cost ($M)	Months Elapsed	Inflation Rate (%)	Cost Escalation ($M)
June 30, 2022	903.70[5]			
Year-end 2022	915.00	6	2.50%	11.30
Year-end 2023	949.77	12	3.80%	34.77
Year-end 2024	1,001.06	12	5.40%	51.29
Year-end 2025	1,055.11	12	5.40%	54.06
Year-end 2026	1,126.34	12	5.40%	71.22
			Subtotal	***222.63***
Opening Cost ($M)	903.7	*A*		
Inflation Increase $M)	222.6	*B*		
Closing Cost ($M)	**1,126.3**	*C = A+B*		
Line Length (km)	450	*D*		
Unit Cost ($M / km)	2.5	*E = C/D*		

[5] This is the cost for rate recovery for the East-West Tie Line as documented in Docket EB-2023-0298, Table Ex.A.1 of $934.2 million less the adjustment for real estate $23.3 million less adjustment for real estate pertaining to the cost overrun allocations (i.e. $2.17 million as per Table Ex.D.14 - CCVA and $4.98 million as per Table Ex.C.9 - Account 1509 for Covid-19 related costs).

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OEB STAFF INTERROGATORY - 13

Reference:

1. Exhibit B-7-1, Page 11
2. EB-2021-0107, OEB staff-1c)
3. EB-2023-0168, Exhibit B-1-3, Page 3

Preamble:

Hydro One conducted a cost per unit km analysis for the following projects: Hawthorne to Merivale, South Nepean DETL, and WATR Projects constructed by Hydro One, and the East-West-Tie Line which was constructed by Upper Canada 2 Transmission Inc. The cost per km for the comparator projects ranges from $2.4 million to $4.1 million per unit km, with the Waasigan Project at $2.6 million per unit km. Table 2 below summarizes the results of the analysis.

Table 2 - Costs of Line Portion of Comparator Projects

	Hawthorne x Merivale Conductor Upgrade	South Nepean DETL Estimate South Nepean Trans Reinforcement	WATR Ingersoll x Karn x Woodstock	Upper Canada Transmission Inc. East-West Tie Line	Waasigan Transmission Lines Project
Circuit Type	Double	Double	Double	Double	Double/Single[1]
Conductor (kcmil)	1192	997	1443	1192	795
Estimate/Actual	Actual	Actual	Actual	Estimate[2]	Estimated
Cost ($M's)	$39.4	$51.3	$35.6	$935.9	$992.7
Escalation Adjustment[3]	5.4	8.8	13.7	169.88	N/A
Length of Line	12.0	12.2	13.6	450	360

OEB staff notes that 170km of the Waasigan Project is a single-circuit line, representing approximately 47% of the entire Project, while the comparator projects are all double-circuit lines.

OEB staff notes that the conductor sizes for the comparator projects are approximately 25% to 82% larger than the 795 kcmil proposed for the Waasigan Project.

[1] Double circuit length is 190km, single circuit length is 170km.
[2] Hydro One notes that this value is per report from Upper Canada Transmission for the *East-West Tie Line Quarterly Construction Progress Report* dated January 20, 2023. Docket EB-2017-0182.
[3] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

OEB staff notes that three of the four comparator projects – Hawthorne to Merivale, South Nepean DETL, and WATR – have significantly lower line lengths in comparison to the Waasigan Project. The line lengths for each of these three comparators represents less than 4% of the total length of line for the Waasigan Project.

Reference 2 is an interrogatory response provided by Hydro One in its Leave to Construct Application for Ansonville TS and Kirkland Lake TS A8K/A9K Refurbishment Project. The interrogatory requested clarification on why the cost per circuit km of one alternative was higher than another. In response, Hydro One stated the following:

> Economics of scale and efficiencies allow for the per km price to decrease when including additional circuit lengths in construction. While scope of work for Alternative 1 is larger, there are efficiencies for longer transmission lines that decrease project cost associated to the additional scope of work. In this case, cost associated to mobilization/demobilization, material yards, environmental assessments, engineering, consultations, and insulator/ hardware replacement are very similar for the two alternatives. All these factors combined and divided by the increased line length resulted in a lower cost per km for Alternative 1.

In Wataynikaneyap Power LP's (WPLP) transmission system, the Line to Pickle Lake is a 230 kV single-circuit transmission line which is approximately 303 km from a point between Dryden and Ignace to Pickle Lake. The Line to Pickle Lake came into service in August 2022.

Interrogatory:

a) Please conduct a cost per unit km analysis and provide supporting calculations for:
   i. Only the single-circuit line portion of the Waasigan Project
   ii. The Line to Pickle Lake portion of WPLP's transmission system

b) Please explain why comparing the cost of the Line to Pickle Lake portion of WPLP's transmission system and the single-circuit portion of the Waasigan Project on a per unit km basis would not be appropriate.

c) Please conduct a cost per unit km analysis for only the double-circuit portion of the Waasigan Project.

d) Could economies of scale and efficiencies gained from longer transmission lines be a driving factor for why the per unit cost of Hawthorne to Merivale, South Nepean DETL, and WATR projects are high in comparison to the East-West Tie Line and the Waasigan Project? If not, please explain why.

e) Has Hydro One applied any adjustment factors to account for the larger conductor sizes amongst the comparator projects in comparison to the Waasigan Project? If yes, please explain the adjustment factors that were applied. If not, please explain why this was not considered.

f) Please provide the calculations for the "Escalation Adjustment" values for the comparator projects noted in Table 2.

Response:

a)

i. Please see Table 1 below, for the cost per unit km analysis and calculation for Phase 2 of the Waasigan Project (i.e. the single-circuit line portion), as well as the cost per unit km analysis for Phase 1 of the Waasigan Project (i.e. the double-circuit line portion) for comparable purposes and in response to part c).

Table 1 - Unit Cost Analysis for Waasigan Lines Project (Phase 1 and Phase 2)

Project (Costs are in $M's)	Waasigan Transmission Lines Project (Phase 2)	Waasigan Transmission Lines Project (Phase 1)
Circuit Nomenclature	D32A	A30L/A31L
Voltage	230 kV	230 kV
Structure Type	Steel Lattice Towers	Steel Lattice Towers
Circuit Type	Single	Double
Conductor	795 kcmil	795 kcmil
Location	Northern Ontario, Rural	Northern Ontario, Rural
In-Service Year	2027	2025
Estimate/Actual	Estimated	Estimated
Cost ($M's)	$447.6M[4]	$546.1M[5]
Less;		
Real Estate	$23.7M[4]	$34.7M[5]
Bypass	N/A	N/A
Micropiles	N/A	N/A
Adjusted Costs ($M)	$423.9M	$511.4M
Escalation Adjustment ($M)	N/A	N/A
Escalated Total Project Cost ($M)	N/A	N/A
Length (km)	170 km	190 km
Unit Cost ($M per km)	**$2.5M/km**	**$2.7M/km**

[4] As per Exhibit B, Tab 7, Schedule 1, Table 4 – Phase 2 Line Cost
[5] As per Exhibit B, Tab 7, Schedule 1, Table 2 – Phase 1 Line Cost

The above analysis for each of the Project's two phases, illustrates that the cost per km results between a single and a double circuit configuration do not significantly differ. Both configurations require right-of ways, towers and foundation work, stringing of conductors, and mobilization and demobilization construction costs. The primary difference driving the above per km cost variance is attributable to the amount of conductor required for a second circuit and the work required to string that additional conductor on the double circuit design of Phase 1.

ii. The Watay Project was not considered for comparison purposes in this Application for leave to construct. After being provided OEB Staff's questions pertaining to the WPLP line, Hydro One has made best efforts to find that Project's details, however information or data at a sufficiently granular level to enable it to perform the analysis requested by OEB Staff was not found. Instead Hydro One utilized readily available public costing information to complete the comparative transmission construction information as provided in Exhibit B, Tab 7, Schedule 1 (in the Project component and Phases cost comparable tables).

As shown in WPLP's s.92 Application (Docket EB-2018-0190), OEB Staff[6] did request unit cost information; however, WPLP's response to cost estimate and cost per km for each individual segment of that project was redacted information, and not publicly disclosed. WPLP also stated cost information only included the direct costs of the transmission line facilities without allocation of indirect costs such as: administrative, general or contingency costs. Consequently, the stratification of costs to dissect the proportion of overall project cost that is attributed to the 230 kV single-circuit component could not be carried out.

Hydro One also reviewed WPLP's more recent s.78 application (Docket #: EB-2023-0168). While updated project forecast information was provided, this information did not fully delineate all project costs pertaining to just the 230 kV single-circuit portion of the project. As such, Hydro One could not conduct the analysis requested in this question.

b) Please see response to part a-ii) above.

c) Please see response to part a-i) above

d) Yes, economies of scale and efficiencies gained from longer transmission lines like Waasigan have the potential to produce lower cost per km, compared to similar designed and scoped transmission circuits of a shorter length. The efficiencies arise

[6] EB-2018-0190, Board Staff Interrogatory #26, part a).

from the ability to spread a transmission project's fixed costs over a larger number of units (in this case kms), such as those items relating to; project management, permitting and regulatory approvals, mobilization, and demobilization,

e) No, Hydro One did not apply any adjustment factors to account for the differing conductor sizes amongst the comparator projects. The purpose of conductor sizing is to ensure that the conductor chosen would be prudent to the rate payer, in terms of line loss considerations. The optimal conductor size and rating utilized is based on the expected load scenario of the project to provide a reliable supply to customers in the area. This is specific to each project. The optimum conductor size affects the engineering and design solution for the project, material and hardware requirements, and equipment and labour requirements for installation. These are costs associated with conductor size and cannot be extracted as a discrete cost that is then used for comparative purposes.

f) The calculations for the "Escalation Adjustment" values for the comparator projects noted in Exhibit B, Tab 7, Schedule 1, Table 7 (and as summarized in Table 2 of the Preamble above) are provided in Tables 3 to 6 below.

Table 3 - Hawthorne x Merivale Conductor Upgrade

End Period	Cost ($M)	Months Elapsed	Inflation Rate (%)	Cost Escalation ($M)
June 30, 2023	***38.50***			
Year-end 2023	39.23	6	3.80%	0.73
Year-end 2024	40.72	12	3.80%	1.49
Year-end 2025	42.27	12	3.80%	1.55
Year-end 2026	43.88	12	3.80%	1.61
			Subtotal	***5.38***
Opening Cost ($M)	38.5	*A*		
Inflation Increase ($M)	5.4	*B*		
Closing Cost ($M)	43.9	*C = A+B*		
Line Length (km)	12.0	*D*		
Unit Cost ($M / km)	3.7	*E = C/D*		

Table 4 - South Nepean Transmission Reinforcement[7]

End Period	Cost ($M)	Months Elapsed	Inflation Rate (%)	Cost Escalation ($M)
November 30, 2021	***40.90***			
Year-end 2021	40.97	1	2.00%	0.07
Year-end 2022	41.99	12	2.50%	1.02
Year-end 2023	43.59	12	3.80%	1.60
Year-end 2024	45.24	12	3.80%	1.66
Year-end 2025	46.96	12	3.80%	1.72
Year-end 2026	48.75	12	3.80%	1.78
			Subtotal	***7.85***
Opening Cost ($M)	40.9	*A*		
Inflation Increase ($M)	7.9	*B*		
Closing Cost ($M)	48.8	*C = A+B*		
Line Length (km)	12.2	*D*		
Unit Cost ($M / km)	4.0	*E = C/D*		

[7] The escalation adjustment in the prefiled evidence for this comparison project contained a small clerical error, and the calculation of the appropriate increase is show in this table. The impact of the error results in a $0.1M reduction to the cost per km, to that in the prefiled evidence Table 4.

Table 5 - WATR Ingersoll x Karn x Woodstock

End Period	Cost ($M)	Months Elapsed	Inflation Rate (%)	Cost Escalation ($M)
March 30, 2012	***30.80***			
Year-end 2012	31.26	9	2.00%	0.46
Year-end 2013	31.89	12	2.00%	0.63
Year-end 2014	32.52	12	2.00%	0.64
Year-end 2015	33.18	12	2.00%	0.65
Year-end 2016	33.84	12	2.00%	0.66
Year-end 2017	34.52	12	2.00%	0.68
Year-end 2018	35.21	12	2.00%	0.69
Year-end 2019	35.91	12	2.00%	0.70
Year-end 2020	36.63	12	2.00%	0.72
Year-end 2021	37.36	12	2.00%	0.73
Year-end 2022	38.30	12	2.50%	0.93
Year-end 2023	39.75	12	3.80%	1.46
Year-end 2024	41.26	12	3.80%	1.51
Year-end 2025	42.83	12	3.80%	1.57
Year-end 2026	44.46	12	3.80%	1.63
			Subtotal	***13.66***
Opening Cost ($M)	30.8	*A*		
Inflation Increase ($M)	13.7	*B*		
Closing Cost ($M)	44.5	*C = A+B*		
Line Length (km)	13.6	*D*		
Unit Cost ($M / km)	3.3	*E = C/D*		

Table 6 - Upper Canada Transmission Inc. East-West Tie Line

End Period	Cost ($M)	Months Elapsed	Inflation Rate (%)	Cost Escalation ($M)
June 30, 2022	***912.6***			
Year-end 2022	924.01	6	2.50%	11.41
Year-end 2023	959.12	12	3.80%	35.11
Year-end 2024	995.57	12	3.80%	36.45
Year-end 2025	1,033.40	12	3.80%	37.83
Year-end 2026	1,082.48	12	3.80%	49.09
			Subtotal	***169.88***
Opening Cost ($M)	912.6	*A*		
Inflation Increase ($M)	169.9	*B*		
Closing Cost ($M)	1082.5	*C = A+B*		
Line Length (km)	450	*D*		
Unit Cost ($M / km)	2.4	*E = C/D*		

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OEB STAFF INTERROGATORY - 14

Reference:

1. Exhibit B-7-1, Pages 7-8
2. Exhibit E-1-1, Page 8

Preamble:

At the first reference, Hydro One identifies land acquisition as a primary risk of the project, and specifically owners refusing Hydro One voluntary agreements which may lead to expropriation. At the second reference, Hydro One provided Table 3 below which sets out the status of the land acquisition process as at the date of filing the Application.

Table 3 - Land Acquisition Status

Property Type	Number of Properties	Early Access Agreement Offered	Early Access Agreement Achieved	Voluntary Settlement Agreements Offered	Voluntary Settlement Agreements Achieved	Issues	Resolution Approach
Private	Phase 1: 156 Phase 2: 78	97% Pending	79% Pending	Pending Pending	Pending Pending	- Routing - Construction and Access - Future Maintenance - Trespassing - Etc.	- Continue to negotiate - Accommodate minor route refinements where and to the extent possible
Federal	Phase 1: 0 Phase 2: 1	N/A Pending	N/A Pending	N/A Pending	N/A Pending	- None to date	- N/A
Crown	Phase 1: 5 Phase 2: 7	100% Pending	100% Pending	Pending Pending	Pending Pending	Proximity of structures to designated transportation expansion areas	Locate structures in undesignated locations where they are situated on Crown lands
Municipal	Phase 1: 1 Phase 2: 7	100% Pending	100% Pending	Pending Pending	Pending Pending	None to date	N/A
OPG	Phase 1: 0 Phase 2: 2	N/A Pending	N/A Pending	N/A Pending	N/A Pending	None to date	N/A
Railway	Phase 1: 2 Phase 2: 2	N/A N/A	N/A N/A	Pending Pending	Pending Pending	None to date	N/A

Interrogatory:

a) Please update Table 3 to reflect the current status of land acquisition.

b) Please indicate when Hydro One anticipates securing the remaining voluntary agreements?

c) If Hydro One fails to secure voluntary agreements with all affected landowners, is it Hydro One's intention to seek expropriation allowances? If so, please describe the expropriation process Hydro One intends to follow as well as its timing. Please comment on whether the timing of securing voluntary agreements or seeking expropriation allowances could impact the construction schedule or in-service date.
   i. Please provide the total cost estimate related to potential expropriation activities for the proposed project.
   ii. Are the costs related to expropriation (including potential OEB proceeding) included in the costs estimate for the Project or will they be incremental to the project costs estimated in the Application?

d) OEB staff notes that for the private properties in the table above, Hydro One has stated "etc." under the "Issues" column. Please identify and explain the other issues that have been identified.

e) OEB staff notes that under the "Resolution Approach" column, Hydro One states "Accommodate minor route refinements where and to the extent possible".
   i. Please define what a minor route refinement is and provide an example.
   ii. If applicable, please list any route refinements that have been proposed to landowners during negotiations and if any have been accepted.

Response:

a) Table 3 is updated as follows:

Property Type	Number of Properties	Early Access Agreement Offered	Early Access Agreement Achieved	Voluntary Settlement Agreements Offered	Voluntary Settlement Agreements Achieved
Private	Phase 1: 145 Phase 2: 77	99% 69%	86% 47%	75% Pending	51% Pending
Federal	Phase 1: 0 Phase 2: 1	N/A Pending	N/A Pending	N/A Pending	N/A Pending
Crown (Provincial)	Phase 1: 5 Phase 2: 7	100% 100%	100% 100%	60% Pending	Pending Pending
Municipal	Phase 1: 1 Phase 2: 7	100% 100%	100% 100%	100% Pending	Pending Pending
OPG	Phase 1: 0 Phase 2: 2	N/A Pending	N/A Pending	N/A Pending	N/A Pending
Railway	Phase 1: 2 Phase 2: 2	N/A N/A	N/A N/A	Pending Pending	Pending Pending

b) The Acquisition of all required property rights through Hydro One's voluntary land acquisition program is the preferred approach. Completion timing is dependent upon landowner-specific negotiations. If Leave to Construct approval is granted on satisfactory terms and conditions, shortly thereafter Hydro One will provide its notice to all remaining outstanding Phase 1 landowners of its intention to seek expropriation relief under s.99 of the Act within a short, prescribed period. After Hydro One has filed its s.99 Application, the incentives found in the voluntary land acquisition program will no longer apply. Compensation for outstanding required land rights will thereafter follow the legislative process.

c) Voluntary property settlement offers are contemplated to be made to all directly impacted property owners. To date, offers have been made to 105 property owners, (out of a total of 151) in Phase 1. Of these, 68 have been accepted.

As stated in part b) above, if Hydro One is unsuccessful in securing 100% of the land rights required via voluntary agreements, shortly after having received OEB s.92 approval Hydro One will seek expropriation authority in accordance with s.99 of the OEB Act. The initial s.99 Application will focus on Phase 1 of the Project to allow Hydro One to move forward expeditiously and achieve the Project's Phase 1 in-service date. Any subsequent s.99 application for Phase 2 of the Project would follow later based on construction timing requirements necessary to achieve the Phase 2 in-service date. This approach allows Hydro One to place focus on negotiating with landowners within each Project phase and to address all in-service timing requirements.

The timing of Hydro One's land acquisition program has been incorporated into the overall project schedule.

i. The total cost estimate for expropriation is dependent upon how many landowners choose not to pursue voluntary settlements and instead proceed through to the expropriation process.

ii. Hydro One's risk registry considers the expropriation risk and accounts for this risk in the total project cost estimate.

d) The items listed in the table are the main and reoccurring issues raised by landowners. The issues covered by 'etc.' represent issues that have been raised infrequently or are site specific. Examples include landowner concerns with the location of livestock during construction and site-specific concerns such as property drainage flows.

e)

i. Minor route refinements may include either, a) minor tower relocations within corridor boundaries that maintain the Project's centreline, and, b) minor route refinements that introduce slight deviations to the corridor boundaries. Both minor tower relocations and route refinements attempt to accommodate landowner specific concerns, such as the unique land use practices or proximity of the line to the landowner's residence.

ii. Minor route refinements have been proposed to ten impacted landowners. Seven of these route refinements have been accepted to date.

OEB STAFF INTERROGATORY - 15

Reference:

1. Exhibit E-1-1, Page 7
2. Exhibit E-1-1, Page 10
3. Exhibit E-1-1, Page 3

Preamble:

At the first reference, the Application states:

> Affected property owners will be advised that they have the option to receive independent legal advice and that Hydro One is committed to reimbursing affected property owners for reasonably incurred legal fees associated with the review and execution of the necessary land rights agreements.

At second reference, Hydro One states that the Early Access Agreement form is similar to a form previously approved by the OEB[1] but noted that this form contains "substantive changes".

The Application states that Hydro One will work directly with impacted property owners to negotiate amicable voluntary agreements, which may in some circumstances include full property buyouts, at the property owner's election.

Interrogatory:

a) How does Hydro One advise affected property owners of the availability of independent legal advice (ILA)? Is this information communicated to property owners orally, or in writing? If the latter, please provide a copy of the standard document.

b) Some, but not all, of the forms of agreement include provisions relating to ILA. Why do only some of the agreements have ILA provisions?

c) Please list the changes in the Early Access Agreement from what has been previously approved by the OEB.

d) How many property owners does Hydro One anticipate will elect for a full property buyout ? What is the forecast cost of such full property purchases (i.e., the incremental costs to purchase the entire property instead of acquiring an easement)?

[1] EB-2022-0140, Exhibit E, Tab 1, Schedule 1, Attachment 1.

Response:

a) Hydro One's project specific Land Acquisition Compensation Principles ("LACP") is provided to all impacted property owners. The availability of independent legal advice ("ILA") that is afforded to all impacted property owners is a principle found in the LACP and is stated as follows:

> Hydro One commits to reimbursing Property Owners for reasonably incurred transaction costs (such as lawyer's fees) associated with the review and completion of applicable conveyancing documents.

Hydro One's LACP for the Project is provided as Attachment #1 to this Exhibit.

Hydro One's Land Representatives are instructed to discuss all aspects of the LACP, including the availability of ILA, with impacted property owners as part of one-on-one discussions.

b) All forms of property rights agreements are subject to reimbursement for ILA. Exclusion of this provision in any agreements is not intentional. Hydro One also commits to reimbursing impacted property owners for reasonably incurred transaction costs (such as ILA) associated with the review and completion of applicable conveyancing documents.

c) Various project-specific updates to the previously approved document have been made to reflect its usage in the Waasigan Transmission Line Project. The single material change between the two agreements is Hydro One's ability to use as much of the impacted property as may be reasonably necessary to access the new corridor.

d) In Phase 1, 18 properties are eligible for a full property buyout under the LACP. As of writing, owners of 9 of these impacted properties have agreed to voluntary full property buyouts. In Phase 2, 6 properties are eligible for a full property buyout. Offers in this respect are anticipated to be issued in early to mid-2024. Hydro One is unable to provide a forecast pertaining to whether property owners will accept full property buyout offers in the future, as this decision is at the discretion of the landowner.

For impacted properties within Phase 1, if all the properties that are eligible for a full property buyout are accepted, the forecast total cost is estimated to be $10M. A forecast of the incremental cost to purchase versus acquiring an easement over those indicated properties is not available as the total costs Hydro One would incur need to include compensation for the cost of structures removed. Hydro One does not have this information at this time, because an offer based on an easement being granted on these properties has not been prepared for all owners who are eligible for the full

property buyout option. Hydro One would not prepare and present that option unless expressly requested by the landowner.

Hydro One's practice of offering full property buyouts in certain circumstances is mitigated by acquiring the full parcel, constructing the Project, and then, as appropriate and after assessment, re-selling the altered full parcel with the Project's necessary easement/s allowing ongoing operation, maintenance and potential expansions. The revenues received from the sale of any full property buyout are treated as reductions to future transmission revenue requirements, as and when the properties are sold and take into account the timing of future revenue requirement applications.

Appraisal reports have not been completed for impacted properties within Phase 2, thus a cost estimate is not available at this time.

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Filed: 2023-12-19
EB-2023-0198
Exhibit I-1-15
Attachment 1
Page 1 of 12

WAASIGAN TRANSMISSION LINE

LAND ACQUISITION COMPENSATION PRINCIPLES

Transmission Project

WAASIGAN TRANSMISSION LINE

I. Introduction

Waasigan
Transmission Project

Land Acquisition Compensation Principles

Hydro One Networks Inc. ("Hydro One") has initiated the Environmental Assessment ("EA") and selected a preferred route for the Waasigan Transmission Line (the "Project") to construct a new 230 kilovolt ("kV") transmission line approximately 400 kilometres in length. Hydro One is now proceeding with the acquisition of the required property interests for the Project. The preferred route where Hydro One's property interests are proposed is referred to in this document as the "Project Corridor". A map of the Project Corridor is outlined in Appendix A.

Hydro One's goal is to secure voluntary property settlements with directly impacted property owners ("Property Owners") in a timely manner. To facilitate this process, it is important that Hydro One's land acquisition compensation principles are communicated to and understood by Property Owners in advance. Furthermore, it is also important that Property Owners are assured these compensation principles will be applied in a fair, transparent and consistent manner.

These project-specific land acquisition compensation principles are founded upon Hydro One's past experience pertaining to land acquisition matters for new transmission line projects. Hydro One's central consideration is the need for Property Owners to have flexibility and choice while balancing Hydro One's desire to achieve timely acquisition of property interests and its obligation to ensure that expenditures are fair and reasonable to ratepayers.

Adoption and application of these compensation principles provides real value for timely settlements and to otherwise avoid potentially lengthier, less flexible and less certain outcomes associated with the legislated expropriation process.

II. Acquisition Process

A. Project Need, Corridor Identification and Approvals

The Project need was previously identified by the Independent Electricity System Operator (IESO). In 2018, the IESO requested Hydro One to begin development work to build a new double-circuit 230 kV transmission line between Lakehead Transformer Station ("TS") and Mackenzie TS (Phase 1), and a new single-circuit 230 kV transmission line between Mackenzie TS and Dryden TS (Phase 2).

The Project will increase power capacity to the region to address forecasted load growth associated with mining developments and the connection of renewable energy in Northwestern Ontario. For more information on the Project please visit **www.HydroOne.com/Waasigan**.

The Project is subject to a comprehensive environmental assessment ("EA") under Ontario's Environmental Assessment Act. Construction of the Project will also require approval from the Ontario Energy Board ("OEB"). It is anticipated that Hydro One will submit an application to the OEB in mid-2023.

B. Introduction and Overview

In parallel to the EA and OEB approvals ("Approvals"), Hydro One will proceed with the land acquisition process for the Project. The process will commence with individual meetings between Hydro One's dedicated Real Estate Representatives and Property Owners. This meeting is intended to review and discuss the process and land acquisition compensation principles, as set out in this document. Property Owners will be provided the necessary time throughout the process to review the materials, complete follow-up meetings and have discussions with their Hydro One Real Estate Representative.

C. Allowance Payment and Access to the Preferred Route

At the initial meeting with impacted Property Owners, Hydro One's Real Estate Representative will offer two immediate payments:

(i) An immediate Allowance Payment of $5,000 in recognition of the Property Owner's time taken to receive and discuss Hydro One's real estate requirements throughout the Project.
(ii) An immediate Access Payment of $2,500 for allowing Hydro One's consultants access to and along the Project Corridor to conduct environmental studies, engineering studies, land appraisal reports and legal surveys of the Project Corridor. In addition to this immediate payment, Hydro One commits to pay for any damages that may occur given Hydro One's and their consultants' presence for the Project during this access requirement.

Acceptance of the Allowance Payment and Access Payment does not obligate the Property Owner to convey any permanent land rights to Hydro One for the Project Corridor.

D. Preparation of Independent Property Appraisal Reports and Other Project Studies

Hydro One and its consultants will collect all pertinent property information in support of the Project. The consultants include accredited independent appraisers who will prepare site-specific appraisal reports. These reports will quantify the fair market value of each property interest on the Project Corridor along with injurious affection, if applicable.

All appraisers retained by Hydro One have received an Accredited Appraiser Canadian Institute (AACI) designation from the Appraisal Institute of Canada. This ensures that appraisals are conducted in accordance with professional standards established by the Appraisal Institute of Canada.

These independent site-specific appraisal reports will be completed through the Spring and Summer of 2023.

E. Preparation of Hydro One Property Rights Acquisition Offers

Hydro One will present each Property Owner with a formal offer based upon the information contained in the independent site-specific appraisal report. As part of Hydro One's formal voluntary land acquisition offer ("Offer"), Property Owners will be provided with a copy of the appraisal report, together with a sketch plan of the property interest to be acquired.

F. Next Steps

Following receipt and consideration of Hydro One's Offer, the next steps in the process will depend upon whether individual Property Owners consider Hydro One's Offer acceptable. If the Offer is accepted, the acquisition process will proceed and the parties will finalize the transaction.

However, if the Property Owner elects to further assess/review the Offer utilizing an independent appraiser to complete an additional site-specific appraisal, Hydro One will reimburse the Property Owner up to $7,500, which is the expected cost of an additional site-specific appraisal report. To be eligible for this reimbursement, the Property Owner must notify Hydro One of its decision to retain independent appraisal services. An independent appraisal carried out for the Property Owner must be conducted by an AACI accredited appraiser and a copy of the site-specific appraisal report is to be provided to Hydro One before reimbursement is paid. If a Property Owner proceeds with this choice, they will forgo the 'Acceptance of the Hydro One Offer' incentive (as described in Section III, Parts B & C).

Reimbursement of the above-noted independent appraisal costs is in no way intended to bind the Property Owner to voluntarily convey the property interests required by Hydro One.

Hydro One's Offer will remain open for acceptance for a limited period of time. Property Owners are assured of reasonably sufficient time to consider the Offer, inclusive of the required efforts of independent appraisal and legal reviews as may be initiated by the Property Owners.

If the parties are unable to complete a voluntary property settlement, Hydro One will file an application to seek expropriation authority status pursuant to Section 99 of the *Ontario Energy Board Act,* 1998 *("OEB Act")*. Property Owners will be given written notice prior to Hydro One filing this application. Once the application is filed, Hydro One's current Offer will lapse and the Property Owner will be provided a revised Offer.

While the revised Offer will comply with the compensation requirements of the *Expropriations Act*, it will include limited compensation incentives (as described further in this document), resulting in a reduced Offer.

III. Compensation Principles

A. General Principles

This section describes the principles Hydro One will follow in respect to the voluntary settlement of property interests for the Project:

Property Owner Choice

Property Owners will be offered the choice of Hydro One acquiring either an easement or the fee simple interest in the lands required for the Project Corridor.

Independent Property Valuation

Hydro One's Offers will be based upon site-specific appraisal reports prepared by external, independent AACI accredited appraisers. The appraiser will be directed to complete site-specific appraisals which will include a Property Owner interview and inspection of the property. In addition, the appraiser will be directed to consider properties as unencumbered, which ignores any other existing encumbrances that may be present (e.g., existing transmission lines and underground utilities).

Incentive-Based Compensation Offers

Compensation premiums, over and above fair market value as set out herein, will be made available as an incentive to achieve the timely acquisition of required property interests. Incentives will be applied on a fair, transparent and consistent manner.

Mitigating Physical Property Damages

Upon acceptance of the Offer by the Property Owner and subject to Approvals, Hydro One will complete the acquisition of the property interests and commence construction activities in accordance with its plans and schedule. During pre-construction and construction activities, Hydro One commits to working with Property Owners to ensure physical property damages are mitigated. If mitigation is not possible, Hydro One will compensate Property Owners for all physical damages that arise out of the pre-construction and construction related activities by Hydro One and/or its contractors.

B. Principles Applicable to the Acquisition of Easement Interests

This section describes more specific compensation principles applicable to the voluntary acquisition of easement interests. Hydro One commits to implementing the following easement compensation principles:

Valuation of Easement Interest

Hydro One's Offer will value all easement interests based upon 75% of the appraised fair market value of the subject property applied to Hydro One's individual property requirements.

Injurious Affection

Compensation for injurious affection is provided when reductions to the market value of the remaining property interests are estimated to result from Hydro One's use of the interest in the portion of the property required for the Project. This amount is determined as part of the independent appraisal process. The analysis takes into consideration various attributes of the remaining property and whether a loss in market value is likely to result from the construction and operation of the Project.

Hydro One will ensure that all appraisals prepared by Hydro One's independent appraisers consider and, where applicable, make provision for any injurious affection arising to the remaining acreage of the property directly impacted by the Project Corridor that is owned by the Property Owner.

Incentive Compensation

Property Owners who accept Hydro One's Offer to acquire easement interests will be provided with the following incentive compensation amounts:

Premium Above Fair Market Value

An amount equal to 50% of the appraised fair market value of the acreage over which the easement interest will be taken. This equates to a total fair market value payment of 125% for the easement interest required for the Project Corridor; plus

Option Payment

An Option payment of $10,000 to be paid at the time the option agreement is registered; plus

Acceptance of the Hydro One Offer

At the time Hydro One exercises the Option (i.e., after the Project receives all required approvals), a further payment of $10,000. Payment of this incentive is conditional on the Property Owner not requesting reimbursement of costs for an additional independent appraisal report (as described in Section II, Part F).

Other Compensation

Hydro One commits to reimbursing Property Owners for reasonably incurred transaction costs (such as lawyer's fees) associated with the review and completion of applicable conveyancing documents.

Each Property Owner impacted by the loss of wooded areas on the Project Corridor will be offered a one-time payment recognizing the value of any current merchantable timber. The payment will be based upon a third-party independent valuation.

Hydro One further commits to compensating Property Owners for all damages that arise out of the pre-construction and construction related activities by Hydro One and/or its contractors. The types of construction damages could include but are not limited to rutting of laneways and fence or gate damage. In addition, Property Owners are assured that all damages arising out of the Project will be rectified or reimbursed.

Hydro One will consider on a case-by-case basis whether unique or exceptional circumstances exist which require the payment of additional compensation.

C. Principles Applicable to the Acquisition of a Fee Simple (Ownership) Interest

This section describes the compensation principles that will be applied when Property Owners prefer to sell the fee simple interest (i.e., ownership) in the portion of the property required for the Project instead of an easement interest. In such circumstances, Hydro One will implement the following compensation principles:

Valuation

Hydro One's Offer will value fee simple interests based upon 100% of the appraised fair market value of the subject property applied to Hydro One's individual property requirements.

Injurious Affection

Compensation for injurious affection is provided when reductions to the market value of the remaining property interests are estimated to result from Hydro One's use of the interest in the portion of the property required for the Project. This amount is determined as part of the independent appraisal process. The analysis takes into consideration various attributes of the remaining property and whether a loss in market value is likely to result from the construction and operation of the Project.

Hydro One will ensure that all appraisals prepared by Hydro One's independent appraisers consider and, where applicable, make provision for any injurious affection arising to the remaining acreage of the property directly impacted by the Project Corridor that is owned by the Property Owner.

Incentive Compensation

Property Owners who accept Hydro One's Offer to acquire fee simple interests will be provided with the following incentive compensation amounts:

Premium Above Fair Market Value

An amount equal to 25% of the appraised fair market value of the acreage over which the fee simple interest will be taken. This equates to a total fair market value payment of 125% for the fee simple interest required for the Project Corridor; plus

Option Payment

An Option payment of $10,000 paid at the time the option agreement is registered plus;

Acceptance of the Hydro One Offer

At the time Hydro One exercises the Option (i.e., after the Project receives all required approvals), a further payment of $10,000. Payment of this incentive is conditional on the Property Owner not requesting reimbursement of costs for an additional independent appraisal report (as described in Section II, Part F).

Other Compensation

Hydro One commits to reimbursing Property Owners for reasonably incurred transaction costs (such as lawyer's fees) associated with the review and completion of applicable conveyancing documents.

Hydro One further commits to compensating Property Owners for all damages that arise out of the pre-construction and construction related activities by Hydro One and/or its contractors. The types of construction damages could include but are not limited to rutting of laneways and fence or gate damage. In addition, Property Owners are assured that all damages arising out of the Project will be rectified or reimbursed.

In circumstances where the Property Owner seeks to continue to use the newly-acquired Project Corridor lands, Hydro One will make all reasonable efforts to negotiate a licence-back arrangement for the ongoing occupation and use of the Project Corridor in compliance with Hydro One's licensing policy.

Hydro One will consider on a case-by-case basis whether unique or exceptional circumstances exist which require the payment of additional compensation.

D. Principles Applicable to the Acquisition of a Full Property Buyout

If a Property Owner's permanent primary residence (trailers/mobile homes are not considered permanent) or a major outbuilding is located within the new Project Corridor, Hydro One will offer a one-time choice of either:
(i) Acquiring the Property Owner's entire property on which the Project Corridor is situated; or

(ii) Acquiring only that portion of the Property Owner's property that is on the Project Corridor lands and providing compensation for the loss of the permanent primary residence and/or major outbuilding, including reasonable relocation costs.

This election cannot be subsequently revisited. In such circumstances, Hydro One will implement the following compensation principles:

Principles Applicable to Full Property Buyout Offers

Valuation

The full property will be valued based upon 100% of the appraised fair market value of the entire subject property.

Disturbance Premium

Hydro One will provide a disturbance premium equal to 25% of the fair market value of the entire subject property. This equates to a total fair market value payment of 125% for the full property buyout.

Relocation Costs

Hydro One will reimburse all reasonable relocation costs incurred by Property Owners.

Incentive Compensation

Property Owners who accept Hydro One's Offer to acquire a full property buyout will be provided with the following incentive compensation amounts:

Option Payment

A $20,000 payment paid at the time the option agreement is registered, providing Hydro One with the option to purchase the subject property.

Acceptance of the Hydro One Offer

At the time Hydro One exercises the Option (i.e., after the Project receives all required approvals), a further payment of $20,000 will be made. Payment of this incentive is conditional on the Property Owner not requesting reimbursement of costs for an additional independent appraisal report (as described in Section II, Part F).

Other Compensation

Hydro One commits to reimbursing Property Owners for reasonably incurred transaction costs (such as lawyer's fees) associated with the review and completion of applicable conveyancing documents.

Hydro One will consider on a case-by-case basis whether unique or exceptional circumstances exist which require the payment of additional compensation.

E. Principles Applicable to the Acquisition of a Voluntary Full Property Buyout

Hydro One is prepared to voluntarily acquire a full property buyout in the following circumstance:

This circumstance will arise if a Property Owner's permanent primary residence (trailers/mobile homes are not considered permanent) is located within 100 metres from the centreline of the new Project

Corridor and the Project Corridor is situated on the Property Owner's subject property. This circumstance is intended to provide eligible Property Owners with the choice and opportunity to have Hydro One purchase their full property.

If a Property Owner qualifies for this circumstance, the opportunity to have Hydro One acquire the full property will be available for up to a one-year period from the date the Project is in-serviced. The voluntary buyout election will be included as part of the Offer and will only apply to Property Owners registered on title as of the date of the Offer. This principle will not apply to any successors in title during the one-year period or beyond.

In this circumstance, the Property Owner will have first selected either the easement or fee simple option (Section III, Parts B & C) and therefore prior payments of fair market value, injurious affection (if applicable) and the 'Premium Above Fair Market Value' incentive, will be deducted from the appraised full parcel fair market value determination.

Principles Applicable to Voluntary Full Property Buyout Offers

Valuation

The full parcel will be valued based upon 100% of the appraised fair market value of the entire subject property as of the date the Property Owner elects this option.

Other Compensation

Hydro One commits to reimbursing Property Owners for reasonably incurred transaction costs (such as lawyer's fees) associated with the review and completion of applicable conveyancing documents.

Hydro One will consider on a case-by-case basis whether unique or exceptional circumstances exist which require the payment of additional compensation.

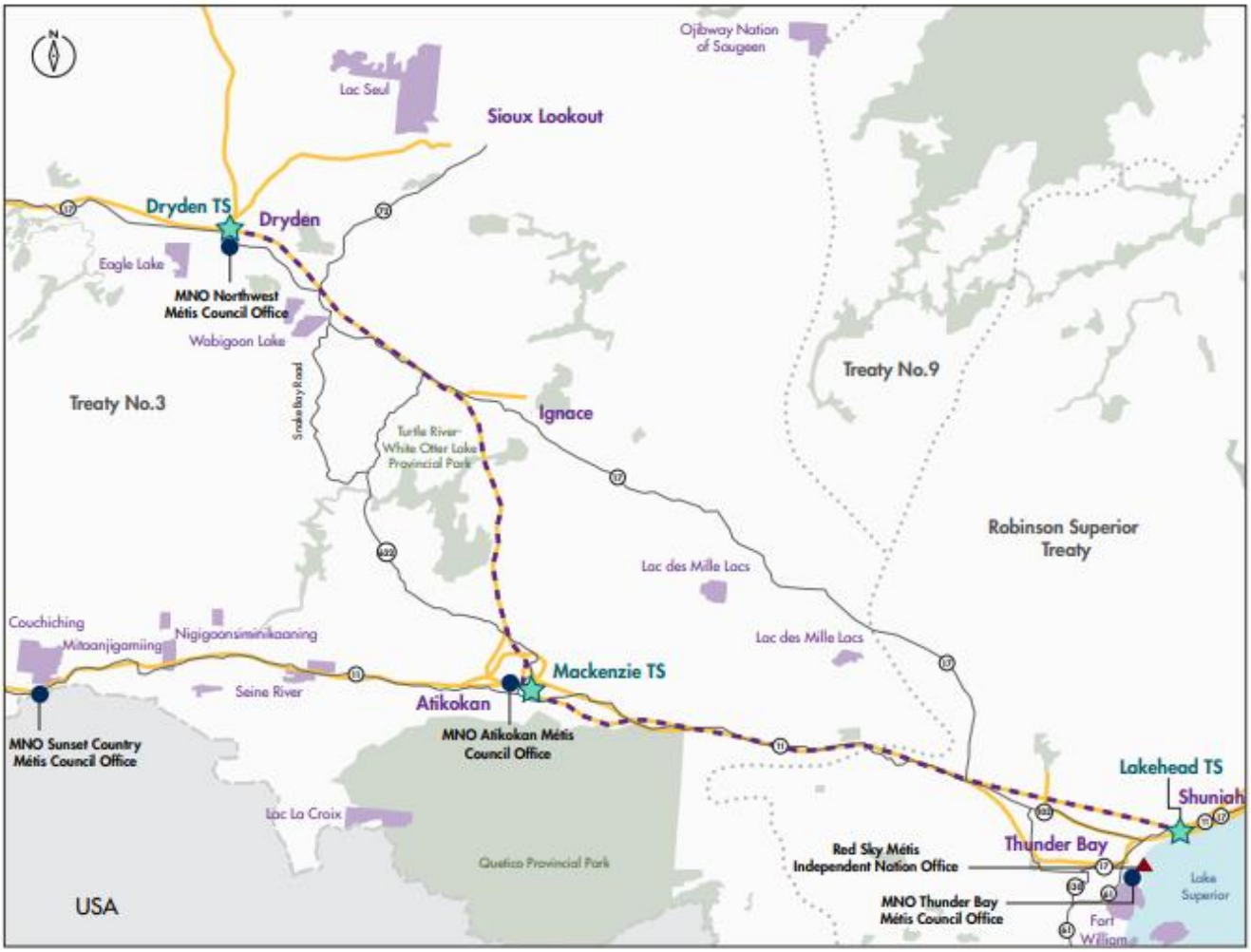
F. Summary

Hydro One aims to enter into option agreements with Property Owners to acquire an easement/fee simple interest in the Project Corridor or, if applicable, a mandatory/voluntary full property buyout. The land acquisition compensation principles (other than reimbursement of independent appraisal costs as discussed in Section II, Part F of this document) will be incorporated into the terms and conditions of the agreement(s) made between Hydro One and the Property Owners, which form part of the option agreement.

At the time the option agreement is registered, Hydro One will pay Property Owners an incentive compensation amount of $10,000. Hydro One will pay the balance of the agreed upon compensation and incentive amounts if and when the Approvals for the Project are obtained and the option agreement is exercised by Hydro One.

Hydro One commits to having its Offer remain available to Property Owners until such time as Hydro One decides to seek expropriation authority status pursuant to Section 99 of the *OEB Act*. This step will happen only if and when required approvals for the Project have been obtained.

Appendix A
Map of 230 kV Transmission Corridor Route



Map Legend

- Existing Transformer Station (TS)
- Preliminary Preferred Route
- Existing Transmission Line
- Highway
- International Border
- Red Sky Métis Independent Nation Office
- Métis Nation of Ontario (MNO) Council Office
- Treaty Boundary
- First Nation Reserve
- Provincial Park

FOR MORE PROJECT INFORMATION:

www.HydroOne.com/Waasigan

Interactive Map: https://arcg.is/vb9G1

OEB STAFF INTERROGATORY - 16

Reference:

Exhibit E-1-1, Attachment 8, Page 2

Preamble:

Clause 3 of the Off-Corridor Access Road Agreement states:

> The term of this Agreement and the permission granted herein shall be two (2) years from the date written above (the "Term"). HONI may, in its sole discretion, and upon 10 days notice to the Grantor, extend the Term for an additional length of time, which shall be negotiated between the parties.

Interrogatory:

a) Please comment on the interplay between the extension being at the sole discretion of Hydro One, and yet the length of the extension will still be the subject of negotiations between Hydro One and the Grantor? If the length of the extension cannot be agreed to, does Hydro One retain the right to extend the agreement?

Response:

a) As noted in this agreement, the "Activities" being contemplated are pre-construction in nature. This agreement only contemplates off-corridor access requirements prior to Hydro One's planned construction start date. The two-year timeline for this agreement is anticipated to be a sufficient term to support these off-corridor access activities.

Although not anticipated, there may be situations where Hydro One may require additional time for off-corridor access to complete pre-construction activities. In these circumstances, the Off-Corridor Access Road Agreement gives Hydro One the right to extend the agreement, upon the serving of 10 days' notice. Recognizing the inconvenience this may cause to the landowner, Hydro One intends to negotiate the length of time required for the extension. Given the subject is pre-construction activities, the length of the extension is of a finite length. Hydro One believes that negotiating this extension length allows it to meet project objectives while at the same time gives the landowner some control over the duration of which these activities may impact their operations.

Hydro One does not interpret this agreement as retaining a unilateral right to extend its duration on terms and conditions of its choosing. Absent a mutually satisfactory resolution, Hydro One's recourse would likely include alternate means of achieving the necessary access or such other rights (e.g., expropriation; rights of ingress and egress) as may be contemplated in other agreements or prescribed by legislation.

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OEB STAFF INTERROGATORY - 17

Preamble:

The OEB typically imposes a set of standard conditions of approval (Schedule 1) as part of its leave to construct approvals. As stated in the OEB's Filing Requirements for Electricity Transmission leave to construct applications, applicants should expect to meet those standard conditions. If an applicant believes that a condition should be modified, the applicant must request any proposed changes and provide supporting rationale in its application.

Interrogatory:

a) Please comment on the OEB's standard conditions of approval for electricity transmission leave to construct applications noted above. If Hydro One does not agree with any of the specific draft conditions of approval noted below, please identify the specific conditions that Hydro One disagrees with and explain why. For conditions in respect of which Hydro One would like to recommend changes, please provide the proposed changes.

Response:

a) Hydro One takes no issue with receiving the standard conditions of approval for this Project.

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OEB STAFF INTERROGATORY - 18

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

Preamble:
The table at the above noted reference estimates the impact of the Waasigan Project on the typical residential customer.

Interrogatory:
a) Please confirm the consumption (kWh) per month that is assumed for the typical residential customer.

b) If the estimate does not assume a residential consumption of 700 kWh per month, please recalculate the table to reflect a residential consumption of 700 kWh.

Response:
a) The consumption per month assumed for the typical residential customer is 750 kWh per month consistent with the OEB's direction on Page 57 of the Filing Requirements for Electricity Distribution Rate Applications (dated December 15, 2022)[1]

b) Hydro One is not aware of a change in any OEB requirements to calculate residential consumption using 700 kWh per month. Hydro One notes that the OEB issued *Defining Ontario's Typical Electricity Residential Customer 2023 Update* on December 13, 2023 that on page 4 reaffirms the consumption for a typical average residential customer is 750kWh/month. However, Hydro One has updated the table in response to the request.

A. Typical monthly bill	$128.94 per month
B. Transmission component of monthly bill	$14.31 per month
C. Line Connection Pool share of Transmission component	$1.39 per month
D. Transformation Connection Pool share of Transmission component	$4.71 per month
E. Network Connection Pool share of Transmission component	$8.21 per month
F. Impact on Line Connection Pool Provincial Uniform Rates	0.00%
G. Impact on Transformation Connection Pool Provincial Uniform Rates	0.00%
H. Impact on Network Connection Pool Provincial Uniform Rates	6.33%
I. Increase in Transmission costs for typical monthly bill (E x H)	$0.52 per month or $6.24 per year
J. Net increase on typical residential customer bill (I / A)	0.40%

[1] https://www.oeb.ca/sites/default/files/OEB-Filing-Reqs-Chapter-2-2023-Clean-20221215.pdf

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OEB STAFF INTERROGATORY - 19

Reference:
Exhibit B-7-1, Pages 4-15

Preamble:
Hydro One states that the Project lines estimate is based on a fixed price EPC contract that was underpinned by two years of early contractor involvement that allowed two EPC contractors to be involved with the development of Project definition and scoping. Hydro One then issued an RFP, where two qualified EPC contractors provided a fixed price to construct the transmission line of the Project. This procurement process allowed the EPC contractors to obtain competitive market pricing from their suppliers and vendors and to identify and evaluate, engineering, procurement, construction, risks and opportunities during the development of their respective offers. Thus, the cost estimate reflects current market tested EPC pricing to deliver the Project, along with corresponding risk that will be transferred to the EPC contractor.

For the station cost estimate of this Project, Hydro One states that a fixed price EPC execution methodology has been selected to best define and manage project scope, schedule and risk while also providing cost surety in the delivery of a project of this magnitude.

Hydro One states that to construct the large number of new transmission line projects required in Ontario, it has undertaken several new initiatives to deliver these projects in a cost-effective, efficient, and timely manner. Hydro One provide some examples of its initiatives to deliver these new transmission projects which include Early Contractor Involvement (ECI) delivery model.

Hydro One states that the ECI delivery model engages the services of an external engineering firm and the services of EPC contractors (referred to as ECI-EPC). This initiative allows the ECI-EPC contractor to be engaged at an earlier stage of development (typically at a preliminary budgetary estimate stage rather than near the end of detailed estimating or at construction initiation). As such, the ECI-EPC contractor performs many of the development functions that under the standard Hydro One EPC delivery model would be performed internally by Hydro One.

OEB staff notes that the ECI-EPC model is similar to the Construction Manager at Risk (CMAR) model, a project delivery model commonly used for the management of regulated utility assets in other jurisdictions. Like the ECI-EPC model, the CMAR allows the EPC contractor to become involved at an earlier stage of development. CMAR has the potential

to yield time and cost efficiencies by obtaining construction manager input during the design phase and beginning aspects of a construction project before the full design is complete.[1]

Interrogatory:

a) At a high-level, please explain the differences between the ECI-EPC and the CMAR models.

b) Please explain advantages, disadvantages and risks associated with using ECI-EPC model vs the standard EPC delivery model performed internally by Hydro One in delivering large scale projects being added to Ontario's transmission system.

c) Please explain in detail what criteria Hydro One uses to decide whether the ECI-EPC model is appropriate for a particular transmission project?
   i. Please confirm that the ECI-EPC model was not used in the recent Chatham by Lakeshore application?

d) Please estimate the total project cost for the Waasigan Project if the standard EPC delivery model was used.

e) Is there any cost saving from using the ECI-EPC model to deliver the Project versus using the standard EPC delivery model that would be performed internally by Hydro One.
   i. If yes, please confirm whether the cost saving from using the ECI-EPC model is reflected in the total Project cost?

Response:

a) Hydro One does not utilize the CMAR model and as a result is not able to comment on the differences between Hydro One's ECI-EPC model and the CMAR model that is used by other organizations.

b) Hydro One is providing the following advantages and disadvantages of the ECI-EPC model;

   Advantages: The ECI-EPC model adopted by Hydro One for this Project is designed to involve the contractor into the development and design phase earlier than Hydro One's traditional EPC model. Doing so is intended to provide a more efficient and effective approach as the project proceeds through these stages and into the project

[1] Federal Emergency Management Agency, Fact Sheet - Construction Manager at Risk (CMAR) Contracting

construction phase. Continuity within these stages is particularly important for larger scale and complex projects such as the Waasigan Project. Specifically, the ECI-EPC model allows the contractor greater involvement in the project scoping exercise and evaluating risks (and preparing potential solutions and mitigation measures) by having the contractor on board early in the development phase of a project. By having the constructor on board early, some of the early scope of work is performed by the constructor instead of internally by Hydro One thereby allowing Hydro One to avoid expanding its' internal corporate resource that would otherwise perform this service. It offers the project proponent the opportunity to evaluate EPC contractors prior to entering into a construction contract. It enables tailoring contract terms appropriately and at a time that is advantageous to the project schedule. The ECI-EPC model introduces an opportunity for innovation in project design and execution while providing greater cost certainty through increased transparency and risk apportionment.

Disadvantages: The model requires that expenditures are incurred, and made to, the ECI-EPC contractor at an earlier stage of a project development cycle to compensate for their time and investment. This creates the risk that a potential write off will be greater if a project is delayed, requires re-engineered scope, or cancelled. There is often a time lag from the start of the ECI-EPC model to the start of construction. This time lag can result in a change of the availability of the EPC contractor's resources, which in turn could impact performance.

c) Hydro One uses the ECI-EPC model when the scale and complexity of a proposed project requires industry-tested expertise and innovation, increased transparency and prudency, and when risk sharing is warranted but not clearly defined at the onset of a project.

   i. Not Confirmed. The ECI-EPC model was used in the Chatham x Lakeshore[2] Project that received OEB Leave to Construct approval[3] and is now under construction. The ECI-EPC model was effective in supporting that project from development to execution. It was efficient and provided benefits significantly outweighing the initial upfront investment required.

d) The cost of the Waasigan Project, absent the ECI-EPC model approach is not feasible to produce. To have developed the Project, and its corresponding cost estimate, under a standard EPC delivery model would have omitted required scope elements (i.e., consultation requirements on the engineering, design and construction planning).

[2] EB-2022-0140
[3] EB-2022-0140 - OEB Decision and Order, dated November 24, 2022.

These scope elements would then need to be fulfilled through alternative means, such as through additional subcontracts. In so doing, inefficiencies would reasonably result, such as added interface risk between contractors and a lack of understanding of the true magnitude of work required to execute the Project. This would then add risk cost to the Project overall. This is one of the benefits of having an ECI-EPC model during the development of a project of this magnitude and complexity. The resultant fixed price of the EPC is predicated on the knowledge the EPC garnered during the development phase of the project. A better understanding of the level effort to execute the project is developed.

The cost benefits from the efficiencies of the ECI-EPC model are embedded in the estimate[4] and cannot be quantified. As such the resources and inefficiencies to undo the benefits expected to flow from the ECI-EPC is not available nor capable of being estimated with any level of certainty/accuracy. Therefore, a total project cost comparison between utilizing the standard EPC delivery model versus the use of an ECI-EPC model for the Project is not possible.

e) Confirmed, there are potential cost savings from using the ECI-EPC model to deliver the Project versus using the standard EPC delivery model (i.e. absent early involvement).

   i. Confirmed, the savings from the use of the ECI-EPC model for the Waasigan Project are included in the total Project cost forecast.

OEB STAFF INTERROGATORY - 20

Reference:

1. Exhibit B-7-1, Pages 4-7
2. Atrium Economics Report, Exhibit B-7-1, Attachment 1

Preamble:

As noted earlier by OEB staff, for the Project, Hydro One stated that it is using an Early Contractor Involvement (ECI) delivery model. The ECI delivery model engages the services of an external engineering firm and the services of EPC contractors (ECI-EPC). This initiative allows the ECI-EPC contractor to be engaged at an earlier stage of development (typically at a preliminary budgetary estimate stage rather than near the end of detailed estimating or at construction initiation). As such, the ECI-EPC contractor performs many of the development functions that under the standard Hydro One EPC delivery model would be performed internally by Hydro One.

Hydro One developed the ECI-EPC model for execution and construction of the types of large-scale projects that Hydro One anticipates being added to Ontario's transmission system in the future.

Hydro One stated that overhead costs allocated to the Project are for Common Corporate Costs. These costs are charged to capital projects through an overhead capitalization rate. As such they are considered to be indirect overhead.

Hydro One noted that a portion of its overheads are allocated to capital expenditures as recognition of the amount of indirect support required to support Project capital work. These allocated costs (overheads) are additional to any directly attributable costs.

Based on Atrium Economics' recommendations, Hydro One is implementing a new overhead capitalization approach to their Project execution model for large-scale projects, such as the Waasigan Project.

Hydro One stated that a five-year weighted average rounded overhead rate of 3.0% will be applied to these types of projects' annual capital expenditures, as shown in Table 6 tilted "Hydro One's Overhead Capitalization Rate for ECI-EPC Projects."

Interrogatory:

a) Please explain whether all capital expenditures for the Waasigan Project will have the five-year weighted average rounded overhead capitalization rate of 3.0% applied, or

only select capital expenditures. If it is only select capital expenditures, please list these capital expenditures with the associated overhead capitalization rates.

b) If the capital expenditures for the Waasigan Project will have different overhead capitalization rates applied, please explain.

c) Please explain why the 5-year weighted average rounded overhead rate of 3.0% will be applied, instead of 2.5% (5-year weighted average with no rounding), to Projects' annual capital expenditures.

d) Please quantify the impact of the rounding on the overall costs of the Project.

Response:

a) The rounded weighted average overhead capitalization rate of 3.0% is applied to all capital expenditures for this Project. This is the result of 79.5% of expenditures associated with ECI-EPC contractor payments attracting a 1% overhead rate while the remaining 20.5% relates to internal Hydro One incurred capital costs and is attracting the typical overhead rate associated with Hydro One's Standard Operating Model (i.e. the model Hydro One uses for all projects in its capital portfolio). This is discussed at Section 5 of the Atrium Economics Report, *Development of OCR Specific to ECI-EPC Contracted Projects*. Further details on the calculation are provided at Exhibit I, Tab 1, Schedule 21, part a).

b) All capital expenditures for the Waasigan project will have the rounded weighted average overhead capitalization rate of 3.0% applied, as discussed in the response to part a) above.

c) As discussed in Section 5.5 in the Atrium Economics Report, Hydro One reviews and adjusts the OCR periodically to reflect changes in capital spending and associated support costs. Rounding the Overhead Capital Rate ("OCR") reduces in-year volatility as forecast inputs change and aligns with the guiding principles of stability and cost-effectiveness outlined in Section 6 of the Atrium Economics Report. Use of a rounded rate is also consistent with all Hydro One overhead rate implementation as reviewed and approved by the OEB (see EB-2021-0110, Exhibit C, Tab 8, Schedule 2, Table 1).

d) The impact of rounding the overhead rate from just over 2.5% to 3.0% is approximately $5 million, or less than 1% of the total Project cost.

OEB STAFF INTERROGATORY - 21

Reference:

1. Exhibit B-7-1, Pages 4-7
2. Atrium Economics Report, Exhibit B-7-1, Attachment 1

Preamble:

Hydro One stated that ECI-EPC executed projects are multi-year and significantly larger in scale, and cost, compared to most of Hydro One's transmission projects contemplated in its TSP. As a result, many Hydro One Common Corporate functions in support of the ECI-EPC Projects are being directly assigned from common corporate costs centers versus being allocated through an overhead allocation rate.

Hydro One noted that the recommended overhead rate by Atrium Economics is a blended overhead rate determined by the weighted average portion of projects costs which are:

- ECI-EPC and do not rely on corporate support functions
- Non-ECI-EPC and should attract the standard Transmission overhead rate as they rely on corporate support functions

Figure 1 in the Atrium Economics Report shows the Overhead Capitalization Rate (OCR) Methodology. Its output from the methodology consists of overhead capitalization rates for Tx and Dx that are applied to the costs of Tx and Dx capital expenditures, as applicable, to recover the portion of common corporate costs that support capital expenditures for each business.

Section 4 in the Atrium Economics Report states that the common corporate costs incurred by Hydro One to support these ECI-EPC Contracted Projects is of a different level than Standard Hydro One Tx Projects. A significant portion of each project's total cost relates to Owner's Engineer (OE) and ECI-EPC Contracted work (i.e., Hydro One determined that 79.5% of the capital expenditures will be payments to external contractor and only 20.5% will relate to internal Hydro One incurred costs).

Section 5.3 in the Atrium Economics Report states that the resulting total Direct Capital and total Applicable Capital Overhead Costs associated with ECI-EPC Contracted Projects are utilized in an OCR Calculation identical to the OCR Calculation used for the Tx business as approved in Hydro One's 2023-2027 Application. The OCR calculation is calibrated to contain inputs (e.g., total capital expenditures) relating only to ECI-EPC Contracted Projects. This aligns the numerator (i.e., the allocation of costs to these ECI-EPC Contracted Projects) with the denominator (i.e., total capital associated with ECI-

EPC Contracted Projects). The resulting OCR for the 79.5% of costs associated with external contractor payments averaged 1.0% over five years.

Section 5.4 in the Atrium Economics Report states that a blended rate was calculated using the OCR for the 79.5% of costs associated with external contractor payments weighted at 79.5% and the standard delivery Tx OCR weighted at 20.5%. The results are shown in Figure 3 of the Atrium Economics Report.

Section 5.5 in the Atrium Economics Report states that given the proposed multi-year average for the ECI-EPC Contracted Projects, Atrium recommends Hydro One to annually evaluate the OCR calculation for each year and ascertain if the OCR for the 79.5% of costs associated with external contractor payments used in the blended rate should be updated.

The Atrium Economics Report references the Black & Veatch (B&V) Report that was filed in the JRAP proceeding (EB-2021-0110, Exhibit E-4-8, Attachment 1). Atrium Economics noted that its staff member (Mr. Taylor), in his former capacity with and as a subcontractor to B&V, has been the lead expert in connection with the B&V Report.

Interrogatory:

a) Please provide a derivation of the proposed OCR amounts in Table 6 (from 2023 to 2027) reflecting Hydro One's Overhead Capitalization Rate for ECI-EPC Projects. Please provide an explanation, as well as supporting calculations of the derivation.

b) As a high level example, please explain whether the proposed rounded OCR rate for the Project of 3.0% is approximately equal to the sum of:
   - 79.5% multiplied by 1.0% (estimated ECI-EPC Projects portion and associated overhead capitalization rate); and
   - 20.5% multiplied by 10% (estimated Standard Delivery Tx portion and associated overhead capitalization rate) – Note: A 10% percentage has been estimated by OEB staff to factor into the calculations used to derive the proposed rounded OCR rate of 3.0%, given that the rate itself was not disclosed in the application.

c) Please explain why a 10% percentage noted in part b) of this interrogatory is appropriate, when the "Overhead Capitalization Rates and Amounts for Transmission and Distribution" for the period 2023 to 2027 ranged from 8% to 9% in the Hydro One JRAP proceeding.[1]

[1] EB-2021-0110, Exhibit C, Tab 8, Schedule 2, Page 5, Table 1, August 5, 2021

d) Please confirm that the methodology shown in Figure 1 titled "Overhead Capitalization Rate Methodology" in the Atrium Economics Report (which was used to calculated the blended OCR) is the same methodology that was agreed to by parties and accepted by the OEB in the Hydro One JRAP proceeding (EB-2021-0110). If this is not the case, please explain.

e) If the methodology has since been updated, please describe the updates made to the Atrium Economics Report, as compared to the Report on Corporate Cost Allocation Review that was filed in the JRAP proceeding (relating to the Overhead Capitalization Rate Methodology),[2] and state whether any of these changes would materially impact the Project cost amounts.

f) Please explain whether Hydro One will revise its overhead capitalization rate methodology to reflect the methodology proposed in this application (specifically the blended OCR) for its broader transmission and distribution businesses at its next rebasing for those businesses.

Response:

a) The proposed OCR amounts in Table 6 are derived (for 2023 to 2027) by applying the standard transmission OCR against the weighting for internal Hydro One-incurred costs and a weighting applied to the OCR for ECI-EPC Projects. The two weighted averages are then summed together to obtain the blended OCR, as illustrated in Table A below.

Table A - Blended Overhead Capitalization Rates Calculation

Blended OCR Calculation	2023	2024	2025	2026	2027
Standard Transmission OCR[3]	8.1%	7.7%	7.0%	7.3%	7.9%
Weighting	20.5%	20.5%	20.5%	20.5%	20.5%
Weighted Average - Tx OCR	**1.7%**	**1.6%**	**1.4%**	**1.5%**	**1.6%**
ECI-EPC Projects OCR[4]	1.2%	1.2%	1.2%	1.2%	1.2%
Weighting	79.5%	79.5%	79.5%	79.5%	79.5%
Weighted Average - ECI-EPC OCR	**1.0%**	**1.0%**	**1.0%**	**1.0%**	**1.0%**
Blended OCR[5]	**2.6%**	**2.6%**	**2.4%**	**2.5%**	**2.6%**

[2] EB-2021-0110, Exhibit E-4-8, Attachment 1, August 5, 2021
[3] As explained in response to part c) of this interrogatory.
[4] As explained in Section 5 of the Atrium Economics Report, Exhibit B-7-1, Attachment 1
[5] Result is impacted by rounding.

b) As per Table A, provided above, the proposed rounded and blended OCR rate of 3.0% is approximately equal to the sum of:
   - 79.5% multiplied by 1.2% per year (ECI-EPC Projects OCR)
   - 20.5% multiplied by approximately 7% to 8% per year (Standard Transmission OCR)

   As described in Exhibit B, Tab 7, Schedule 7 Table 6, the sums for each year are subsequently averaged for the 2023 to 2027 period to get 2.5%, which was rounded to 3.0%.

c) The 10% estimate used by OEB Staff, in part b) of its Interrogatory above, does not reflect the appropriate standard Transmission OCR rates, that are the outcome of Hydro One's Standard OCR methodology, as approved in JRAP for the 2023 to 2027 period (Docket # EB-2021-0110[6]). The appropriate rate to use to calculate the blended OCR, as reflected in Table A, above, is between approximately 7% and 8.1% per year (across the JRAP approved period), and represents overheads applied to Transmission capital expenditures.

d) Confirmed, the proposal is utilizing the same methodology that was agreed to by parties and accepted by the OEB in Hydro One's 2023-27 JRAP proceeding (EB-2021-0110).

e) The methodology embedded in the report on Common Corporate Costs allocation as filed in the JRAP proceeding (EB-2021-0110) has not been updated, except for refinements as discussed in Section 5 of the Atrium Economics Report, which will be applied to projects meeting certain criteria as defined in Section 4. Using the updated overhead capitalization methodology when considering the existence of the ECI-EPC approach lowers the impact to the project budget by approximately $60M by not charging the Project for components of Hydro One overhead that are being performed by the ECI-EPC contractor.

f) To the extent that the next rebasing application includes ECI-EPC projects that meet the criteria outlined in the Atrium Economics Report, the OCR method proposed in this Application will be applied. Consistent with prior major rate applications, Hydro One will undertake a periodic review of the methodology with an independent expert

[6] Hydro One's standard OCR methodology, as approved in the JRAP, is the recommendation resulting from the Black and Veach Report as filed at EB-2021-0110, Exhibit E-4-8, Attachment 1, August 5, 2021.

consultant to ensure that appropriate cost allocation principles are being reflected in its next rate application.

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OEB STAFF INTERROGATORY - 22

Reference:

1. Exhibit B-7-1, Pages 4-7
2. Atrium Economics Report, Exhibit B-7-1, Attachment 1

Preamble:

Hydro One has provided information regarding the apportionment of the Waasigan Project and risks in its application.

Interrogatory:

a) In calculating the blended OCR, please provide a breakdown of capital expenditures that Hydro One determined to be directly related to the ECI-EPC projects and non ECI-EPC projects (standard delivery Tx), as well as a description for each.

b) Please provide a derivation for the 79.5% of the capital expenditures related to the payments to external contractor.
   i. Please provide an explanation, as well as supporting calculations of the derivation.
   ii. Please provide the resulting OCR for the 79.5% of costs associated with external contractor payments averaged 1.0% over five years in the following format, as well as references:

ECI-EPC Projects	2023	2024	2025	2026	2027	5-year avg.
Utility O&M Prior to Capitalization						
Overhead Capitalization						
Utility O&M						
Overhead Capitalization Rate						

c) Please provide a derivation for the 20.5% of the capital expenditures related to the standard delivery Tx.
   i. Please provide an explanation, as well as supporting calculations of the derivation.
   ii. Please provide the resulting OCR for the 20.5% of costs associated with the standard delivery Tx in the following format, as well as references:

Standard Delivery Tx Projects	2023	2024	2025	2026	2027	5-year avg.
Utility O&M Prior to Capitalization						
Overhead Capitalization						
Utility O&M						
Overhead Capitalization Rate						

d) Please explain the main factors that could affect the percentage (79.5%) of costs associated with external contractor payments.

Response:

a) When calculating the blended OCR, Hydro One considered the capital expenditures for the portfolio of significant transmission system expansion projects spanning multiple years that are forecast to be executed utilizing the ECI-EPC methodology. These projects included:

- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]

The total forecast expenditures of the portfolio until 2027 exceed $[REDACTED] and continues to grow annually after that. The pace of projects is accelerating, since the Atrium Report was prepared, as Hydro One has now been designated the developer of new transmission lines in the northeast and in GTA east. Some projects used in the Atrium Report, such as Chatham by Lakeshore and Waasigan, included the full development and construction estimate to bring in-service, while others that do not have a defined need date from the IESO, such as Longwood by Lakeshore Second Single 500kV Circuit only included expenditures related to preliminary development activities.

It is forecast that all these ECI-EPC projects will require Ontario Energy Board section 92 approval and will be brought forward at the appropriate time once the in-service need is established, and the estimate completed.

The non ECI-EPC projects (standard delivery Tx) are primarily projects utilized for sustainment and natural growth of the Transmission System and were reviewed by the OEB in the JRAP (EB-2021-0110) or other leave to construct applications.

b)

i. The derivation for the 79.5% of the capital expenditures relates to payments to external contractors for engineering, support of the environmental assessment, certain project management functions, certain community and Indigenous engagement, procurement of materials, construction, and quality assurance. The percentage is based upon actuals and the forecast ECI-EPC scope of work for Waasigan and Chatham by Lakeshore. Future projects are forecast to average a similar split between the ECI-EPC and the internal Hydro One effort; the split will be reviewed annually. For the supporting calculations of the derivation, please refer to Hydro One's response to Exhibit I, Tab 1, Schedule 9 part b).

ii. The format that supports the resulting OCR calculation for the 79.5% of costs associated with external contractor payments averaged 1.0% over five years is shown in Exhibit I, Tab 1, Schedule 21a). Both capital and O&M forecast spending are considered as responded to in Exhibit I, Tab 1, Schedule 24 part e).

c)

i. The derivation for the 20.5% of the capital expenditures related to the standard delivery Transmission methodology relates to activities performed internally by Hydro One including Indigenous Relations, overall project management and oversight, a component of the environmental assessment, Real Estate Acquisition, Community Affairs and Commissioning. The percentage is based upon actuals and the forecast scope of work for the Waasigan and Chatham by Lakeshore projects. Future projects are expected to average a similar split between ECI-EPC and internal Hydro One effort. The split will be reviewed annually. The calculation is 100% minus % of capital expenditures to external contractors. For the supporting calculations of the derivation, please refer to Hydro One's response to Exhibit I, Tab 1, Schedule 9 part b).

ii. The format that supports the resulting OCR calculation for the 20.5% of costs associated with standard transmission delivery is shown in Exhibit I, Tab 1, Schedule 21 part a). Both capital and O&M forecast spending are considered as responded to in Exhibit I, Tab 1, Schedule 24 part e).

d) As per Hydro One's in Exhibit I, Tab 1, Schedule 24 part f), the split between the 79.5% ECI-EPC and 20.5% Internal Hydro One is reviewed annually for adjustment based on revised forecast and actuals of individual projects expenditures on ECI-EPC vs Internal Hydro One and the potential impact on the forecast ECI-EPC vs Internal Hydro One effort related to the portfolio of projects.

OEB STAFF INTERROGATORY - 23

Reference:

1. Exhibit B-7-1, Pages 4-7
2. Atrium Economics Report, Exhibit B-7-1, Attachment 1

Preamble:

The Atrium Economics Report states that under the ECI-EPC approach, the OE/EPC contractors perform many of the development functions that would be performed internally under the Standard Delivery Model.

However, Hydro One also states in the application that many Hydro One Common Corporate functions in support of the ECI-EPC Projects are being directly assigned from common corporate costs centers, versus being allocated through an overhead allocation rate.

Interrogatory:

a) Regarding the Project costs, please explain why Hydro One stated that it is directly assigning costs from common corporate costs centers, while at the same time, the Atrium Economics Report states that many of the development functions are being performed by the OE/EPC contractors (instead of internally by Hydro One).

Response:

a) As discussed in section 5.1 in the Atrium Economics Report, some Hydro One employees will directly charge their time to ECI-EPC Contracted Projects in accordance with Hydro One's Capitalization policy, for example, employees in the Line of Businesses such as Real Estate, Indigenous Relations, and System Control. The time spent by individuals supporting the ECI-EPC Contracted Projects relating to project oversight and facilitation is not duplicative of the functions performed by the OE/EPC contractors. For example, the OE/EPC contractors will have little oversight and leadership relating to Hydro One's Indigenous Relations and System Control as those functions relate to Hydro One's facilitation of these ECI-EPC Contracted Projects. Further, while a Hydro One employee from a Line of Business may support the planning and oversight portion of an ECI-EPC Contracted Project; the OE/EPC Contractors will focus on the planning of specific work tasks, material purchasing, and labor readiness for the project.

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OEB STAFF INTERROGATORY - 24

Reference:

1. Exhibit B-7-1, Pages 4-7
2. Atrium Economics Report, Exhibit B-7-1, Attachment 1
3. EB-2021-0169, Hydro One Networks Inc., Decision and Order, October 7, 2021

Preamble:

In the current application, Hydro One stated that in EB-2021-0169, it was granted OEB approval for the ATP Account. This account is being used to track costs for transmission line projects that are expected to be owned by a new transmission partnership.

The ATP Account decision stated that all or part of such projects is expected to be owned by and included in the rate base of a new partnership between Hydro One and one or more partners, as a licensed transmitter, and will not form part of Hydro One's rate base.

Hydro One proposed to use the ATP Account for the Waasigan Project.

The ATP Account decision indicated that a deferral account for the Waasigan Project has been in place for several years. Specifically, this deferral account was first established by an OEB decision issued on March 27, 2015.[1] On September 12, 2019, the OEB issued a decision approving Hydro One's request to change the account from a deferral account to a tracking account.[2]

The OEB determined in the ATP Account decision that the final determination of prudence shall be made at the time that Hydro One or the new partnership applies for disposition of all or part of the ATP Account.

In the background of the ATP Account decision, the following was noted. Hydro One stated that with respect to its proposed methodology for allocation of direct and indirect costs, that direct costs for a project are recorded in Hydro One's financial system using the project's respective project code. Indirect costs are applied by using Hydro One's overhead capitalization methodology that was approved by the OEB as part of Hydro One's most recent revenue requirement application.

In the ATP Account decision, the OEB noted that Hydro One's proposed treatment of costs for the projects using the ATP Account is consistent with the treatment of all of Hydro

[1] EB-2014-0311, Decision and Order, March 27, 2015
[2] EB-2019-0151, Decision and Order, September 12, 2019

One's regulated projects including both direct and indirect costs, as well as the allocation of common transmission lines and stations costs.

In the current application, Hydro One stated that the basis for an update to its overhead allocation rate is that fewer indirect resources (i.e., overheads) from Hydro One are required to support the Project because these overheads are being incurred by the ECI-EPC.

Hydro One further stated that it has implemented recommendations made by Atrium Economics in the Waasigan Project's cost estimate, but OEB staff notes that Hydro One was silent on the implementation date.

Interrogatory:

a) Please explain at what date the change in the overhead capitalization rate methodology will be implemented for the Project, including whether any retroactive impacts have been made (or will be made), given that the ATP Account (in its predecessor form) has been in place for the Project since March 2015.

b) Please explain why the blended OCR does not reflect data from certain historical years, as well as forecast. For example, why are not historical years such as 2022 (actual) and 2023 (actual up to Q3 and forecast Q4), used in the calculations, as opposed to solely 2023 to through 2027 forecasts?

c) Please explain whether the blended OCR for the 2024 through 2027 forecasts are based on the capital spend for the Project.

d) Based on part b) of this interrogatory, please provide the revised calculation of capitalization rates, the impact to capitalized overhead and the Project amounts.

e) Please explain whether Hydro One is proposing that its blended OCR methodology be based forecasted capital versus O&M spending (as opposed to historical), because overhead capitalization rates may be based on forecasted capital work to more accurately reflect both the costs incurred and the capital work undertaken.

f) Please confirm that the accuracy of business unit capitalization rates, which are based on a forecast of capital work to be done in the year, could be improved by updating rates throughout the year. If so, please explain if Hydro One intends to update the rates. If not, why not.

Response:

a) Hydro One implemented the adjusted overhead rate in Q3, 2023 after submitting the leave to construct application to the OEB, as disclosed in Exhibit B, Tab 7, Schedule 1. Hydro One is not implementing any retroactive adjustments on the prior $47.4M of Capital expenditures which has attracted Hydro One's general standard overhead rate, as disclosed to the OEB in the most recent Waasigan OEB Report April 2023 to September 2023.

b) The blended OCR contains two main components, as shown in the response at Exhibit I, Tab 1, Schedule 21, part a). 2023-27 Business Plan figures were used on a best effort basis to align timing of both the Standard Transmission and ECI-EPC Projects OCR's. Both OCR's are applied annually and are an output used in the 2023-27 JRAP Plan to determine the 5-year average blend over the 2023-27 period.

   The blended OCR does not reflect data from historical years because it is used as a rate moving forward to future years. A forward-looking metric should not rely on a historical period, particularly in instances where a new program, process, or organizational structure is newly developed or its importance changes, as the historical period will not accurately reflect the expected future.

c) The blended OCR for 2024 through 2027 is based on all forecast ECI-EPC Contracted Projects, not just the Waasigan Project. The methodology is described in detail in sections 5.3 and 5.4 of the Atrium Economics Report, Exhibit B, Tab 7, Schedule, Attachment 1.

d) Prior to 2023, ECI-EPC project costs were not a material component of the overall Hydro One work program. The assessment or the overhead capitalization rates was initiated in 2023 when Hydro One forecast a material change in the work delivery. Therefore, pre-2023 expenditures were excluded from the calculation. As per the response in part b), above, the 5-year average calculated in Table 6 in Exhibit B, Tab 7, Schedule 1, is considered appropriate.

e) The components of the blended OCR methodology proposed are based on the forecast capital and O&M expenditures and the resulting blended rate is applied to the ECI-EPC projects as identified in part a) response of Exhibit I, Tab 1, Schedule 21. The use of forecast figures rather than historical is to improve accuracy; as outlined in the response to part f) in Exhibit I, Tab I, Schedule 26, the expected growth in ECI-EPC projects has increased significantly since 2022. Furthermore, the use of forward-looking figures is part of the Standard Transmission OCR methodology developed by Black & Veatch and agreed to as part of the decision for Hydro One's joint rate application (see EB-2021-0110, Exhibit E, Tab 4, Schedule 8, Attachment 1).

f) Yes, Hydro One intends to review and update the OCR rate annually. This approach is consistent with the recommendation found in in Section 5.5 of the Atrium Economics Report[3], which states:

> Given the proposed multi-year average for the ECI-EPC Contracted Projects, Atrium recommends Hydro One annually evaluate the OCR calculation for each year and ascertain if the OCR for the 79.5% of costs associated with external contractor payments used in the blended rate should be updated.

[3] Exhibit B, Tab 7, Schedule 1, Attachment 1

OEB STAFF INTERROGATORY - 25

Reference:

1. Exhibit B-7-1, Pages 4-7
2. Atrium Economics Report, Exhibit B-7-1, Attachment 1
3. EB-2021-0169, Hydro One Networks Inc., Decision and Order, October 7, 2021
4. Filing Requirements for Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, Chapter 2, Cost of Service, December 15, 2022, Pages 66 & 67
5. EB-2019-0082, Draft Rate Order, Pages 25 & 26, May 28, 2020
6. EB-2021-0110, Decision and Order, November 29, 2022, Settlement Proposal, Page 86, footnote #70, October 24, 2022

Preamble:

Hydro One proposed to use the ATP Account for the Waasigan Project.

OEB staff notes that the December 31, 2018 balance of $0.9 million in the Waasigan Transmission Line Deferral Account (Formerly NWBTL) was disposed in Hydro One's Hydro One Network Inc.'s 2020-2022 Transmission Custom IR Application.

OEB staff also notes that the Waasigan Transmission Line Deferral Account was the predecessor DVA to the ATP Account. As noted in the JRAP settlement proposal, "the Waasigan Transmission Line Tracking Deferral Account was subsequently closed and transferred to the ATP Account."

Interrogatory:

a) Please explain whether Hydro One will track the difference between the legacy overhead capitalization methodology and the proposed blended OCR methodology until the next rebasing for the Project in a new DVA (e.g., Accounting Policy Changes Deferral Account), or plans to track the differences in the ATP Account.

b) If a new DVA is being proposed, please provide the following:
   i. A draft accounting order for this new DVA
   ii. A discussion on the causation, materiality, and prudence criteria required when requesting the establishment of a new DVA, in accordance with the OEB's direction in its filing requirements

c) If such differences will be tracked in a new DVA or the ATP Account, please explain at which date such differences will be started to track in the specific DVA. If these differences will not be tracked, please explain.

d) Please confirm that such differences to be tracked in the new DVA or the ATP Account would be credit entries to the DVA (i.e., a refund to customers). OEB staff notes that the amount of indirect costs applied to capital expenditures will decrease, given the proposed decline in the overhead capitalization rate by using a blended OCR. If any of this is not the case, please explain.

e) Please provide the annual entries to the DVA or the ATP Account for each year from 2019 to 2023, with a high level description of the methodology used to record these entries. If the entries are to commence using a different year than 2019, please explain.

f) Given that the ATP Account decision did not take issue with Hydro One's proposed treatment of indirect costs, what was the main driver behind Hydro One proposing the different treatment of indirect costs in the current application for the Project? Please explain, including why the blended OCR was only brought forward by Hydro One in the current application to the OEB that fewer indirect resources (i.e., overheads) from Hydro One are required to support the Project.

Response:

a) Hydro One will track Project capital costs, inclusive of capitalized overheads (i.e. those resulting from the blended OCR methodology) in the ATP Account.

b) A new DVA is not being proposed.

c) Not applicable, see part b), above.

d) Not applicable, see part b), above.

e) Not applicable. Refer to part b), above.

f) The main driver behind Hydro One proposing to refine the current Hydro One Overhead methodology is that Hydro One has refined its delivery models. The delivery models were updated to meet the investment required to meet the rapid pace of change and evolution in Ontario's electricity market to support the decarbonizing Ontario's Economy as outlined in the Ontario government's Power Ontario's Growth. To meet the increased system needs, Hydro One developed the ECI-EPC Contracted Projects to leverage external resources on a project basis to have an Owner's Engineer and EPC contractor perform many of the development functions that would be performed internally under the Standard Delivery Model.

At the time of the ATP application and JRAP, the two projects planned to be executed utilizing the ECI-EPC were Waasigan and Chatham by Lakeshore. Until May 2022, the Waasigan Transmission Line only had support and need from IESO to execute development activities and the potential construction activities for Waasigan Phase 1 were forecast to potentially take place after 2030. Therefore, only development activities (ECI) for Waasigan were included in Hydro One's business plan and the total gross expenditures for the entire portfolio of ECI-EPC projects represented less than $400M over the entire period in the 2022 forecast of future expenditures.

Since that time, the IESO has requested Hydro One to complete both Phase 1 and Phase 2 of the Waasigan project. Furthermore, as the Ontario government executes to deliver on the actions outlined in Powering Ontario's Growth, it has issued a number of Order-in-Councils declaring transmission line projects as priorities and directed the Ontario Energy Board to amend Hydro One Network Inc.'s transmission licence to designate it as the transmitter responsible for the development of these lines.

The total ECI-EPC expenditures to support these required investments are now forecast to [REDACTED] $[REDACTED] by 2027 and are [REDACTED] to represent approximately [REDACTED] of Hydro One annual capital expenditures at that time. ECI-EPC expenditures are forecast to continue to grow post 2027.

Due to this material change, Hydro One considered it prudent to request Atrium to assess the impact on its overhead allocation and calculation. The results of this assessment and Atrium's recommendation to refine the current methodology, which is included in the application in Exhibit B, Tab 7, Schedule 1 and were accepted and implemented by Hydro One as disclosed in that exhibit.

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OEB STAFF INTERROGATORY - 26

Reference:

1. Exhibit B-7-1, Pages 4-7
2. Atrium Economics Report, Exhibit B-7-1, Attachment 1

Preamble:

Hydro One has provided information regarding the apportionment of the Waasigan Project and risks in its application.

The Atrium Economics Report states that capitalized overheads are trued-up (in-year) at year-end to reflect actual results for capital implemented under the Standard Delivery Model. Given the proposed multi-year average for the ECI-EPC Contracted Projects, Atrium recommends that Hydro One annually evaluate the OCR calculation for each year and ascertain if the OCR for the 79.5% of costs associated with external contractor payments used in the blended rate should be updated.

Interrogatory:

a) Hydro One plans to evaluate and update the 79.5% percentage annually, as part of the blended OCR rate. Please explain why the other components of the blended OCR rate will not be updated annually.

b) Please explain if the actual capitalization rates change until the next rebasing of the Project, whether this would be reflected in the cost of the Project.

c) Please describe the results of the year-end reviews.

d) Please explain whether the data used in the overhead capitalization methodology will be updated annually, but the base capitalization rates will be set based on the blended OCR of 3.0% and will not change. Please also confirm that this means that Hydro One is not proposing to make adjustments to the Project's costs to reflect annual updates to overhead capitalization rates.

e) Please provide any OEB precedent that allows for a blended overhead capitalization rate similar to that being proposed by Hydro One for the Project, including the EB# and the reference to the relevant evidence.

f) Please provide any OEB precedent that allows the use of one overhead capitalization rate similar to that being proposed by Hydro One for the Project (i.e., the blended OCR), and a different overhead capitalization rate for the remaining Hydro One

businesses (i.e., distribution and transmission), including the EB# and the reference to the relevant evidence.

g) Please explain why the Atrium Economics Report states that while the Overhead Capitalization Rate Methodology uses cost drivers to allocate direct capital and applicable capital overhead costs to the Transmission business, there is no separation between the projects within the Transmission business. Please clarify the statement that "there is no separation between the projects within the Transmission business" when this application proposes separate costs for the Project.

Response:

a) Hydro One plans to evaluate all the components of the blended OCR for the ECI-EPC Contracted Projects annually. The periodic reviewing and adjusting of overhead capitalization rates to reflect changes in costs and spending is per the methodology approved by the OEB as part of Hydro One's 2023-27 JRAP application (EB-2021-0110, Exhibit E, Tab 4, Schedule 8, Attachment 1, Task 6, section 6.3-Overview of Methodology).

In section 5.5 of the Atrium Economics Report, Atrium acknowledges this approach, and recommends that Hydro One continue this practice for the ECI-EPC Contracted Projects.

b) If the blended OCR rate changes following a review, the impact will be reflected in costs incurred by the Project from the date of implementation of the new rate, consistent with the methodology recommended by Atrium Economics in their report.

c) Based on the 2023 year-end review, Hydro One's blended OCR rate for 2024 will be 2.0% (rounded). This is primarily a reflection of Hydro One's growing capital portfolios, both internally and externally (i.e. ECI-EPC) executed perspective.

This also demonstrates that Hydro One is executing an annual evaluation of the blended OCR calculation as recommended in section 5.5 of the Atrium Economics Report (exhibit B-07-01 attachment 01).

d) As per the response to part c) above, the 2023 year-end review has produced an updated blended OCR rate for 2024 of 2.0% (rounded), down from 3.0% (rounded) for 2023. The reviews are intended to ensure that the 79.5% / 20.5% split and resulting calculations continue to be valid as the projects utilizing the ECI-EPC methodology are developed and executed. This means that the 3% blended overhead rate forecast in Exhibit B, Tab 7, Schedule 1 will be evaluated annually as recommended in section 5.5 of the Atrium Economics Report. Hydro One is not proposing adjustment to the

estimate of Project Costs. Any updates to project capital costs resulting from changes to the ECI-EPC OCR will be managed utilizing project contingency.

e) Since ECI-EPC projects are substantially different than a standard Tx project with the role of a contractor, there are distinct cost causation for internal project costs and contractor costs as they relate to overhead costs. The contractor is not causing Hydro One to incur the same level of overhead per a dollar spent as the internal costs. The proposed ECI-EPC methodology is a refinement that aligns with the criteria and methods of the current overhead capitalization process to meet industry changes as per Hydro One response in Exhibit I, Tab 1, Schedule 25 f). This base OCR methodology was reviewed in detail in numerous Hydro One rate hearings, including the most recent JRAP 2023-27 revenue requirement Application - Docket 2021-0110.

f) As disclosed above, the methodology is only a refinement of the current methodology. Hydro One Networks Inc is a single legal entity that includes a distribution and transmission line of business. The OEB in many previous rate decisions has deemed it prudent, just and reasonable to allow the use of one overhead capitalization rate for one part of the business (i.e., transmission) and different overhead capitalization rate for the remaining Hydro One businesses (i.e., distribution). As described in Exhibit I, Tab 1, Schedule 25 f), this refinement was recommended by Atrium (as per Exhibit B, Tab 7, Schedule 1, Attachment 01) to meet the rapidly evolving electricity investments.

g) As discussed in section 5.1 in the Atrium Economics Report, some Hydro One employees will directly charge their time to ECI-EPC Contracted Projects, those in the Line of Businesses; Indigenous Relations, Planning, and System Control. The time spent by these individuals supporting the ECI-EPC Contracted Projects relating to project oversight and facilitation is not duplicative of the functions performed by the OE/EPC contractors. For example, the OE/EPC contractors will have little oversight and leadership relating to Hydro One’s Indigenous Relations and System Control as those functions relate to Hydro One’s facilitation of these ECI-EPC Contracted Projects Further, while a Hydro One employee from the Planning Line of Business may support the planning and oversight project of a ECI-EPC Contracted Project; the OE/EPC Contractors will focus on the planning of specific work tasks, material purchasing, and labor readiness for the project.

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OEB STAFF INTERROGATORY - 27

Reference:

1. Exhibit B-7-1, Pages 4-7
2. Atrium Economics Report, Exhibit B-7-1, Attachment 1

Preamble:

Hydro One has provided information regarding the apportionment of the Waasigan Project and risks in its application.

The Atrium Economics Report recommends reviewing the five-year average of the OCR annually.

Interrogatory:

a) Please confirm that the changes proposed in the Atrium Economics Report related to the Overhead Capitalization Rate Methodology are reflected in the Waasigan Project amounts presented in this application. If this is not the case, please explain.

b) If the changes proposed in the Atrium Economics Report related to the Overhead Capitalization Rate Methodology were not reflected in the Waasigan Project amounts presented in this application, please explain whether this would have a material impact on these project amounts and provide the estimated impact, if material.

c) If the OEB does not approve either the use of the proposed blended OCR methodology for the Waasigan Project, or the recovery of indirect costs on a capitalized basis (e.g., indirect overheads) in general, please explain whether Hydro One plans to recover these amounts elsewhere as part of the Waasigan Project (e.g., added to Hydro One's OM&A when the Project next rebases or added to amounts accumulated in a specific DVA or the ATP Account). If Hydro One plans to recover, please provide further details.

d) Please explain in more detail the impacts on the proposed blended OCR methodology for the Waasigan Project, if Hydro One chose to use internal labour, as opposed to outsourcing a large part of the capital program for the Project (i.e., using the ECI-EPC).

Response:

a) Confirmed. The changes proposed in the Atrium Economics Report related to the Overhead Capitalization Rate Methodology are reflected in the estimate presented in Exhibit B, Tab 7, Schedule 1. The estimate utilized the 3% rate as presented in the Application.

b) Not applicable. See response to part a) above.

c) If the OEB does not approve the proposed blended OCR methodology, Hydro One will continue to utilize the existing OCR methodology. The OEB approved Hydro One's current methodology for overhead allocation, in the 2023-27 JRAP revenue requirement application[1]. This methodology is consistent with US GAAP and permits the capitalization of indirect overheads. Please see Exhibit I, Tab 1, Schedule 29 regarding Hydro One's use of US GAAP.

Absent the methodology proposed in this application, consistent with that recommended by Atrium, the impact to the project would be to increase overhead costs by approximately $50 million. Please refer to Exhibit I, Tab 1, Schedule 30 for details. Hydro One believes that the proposed OCR methodology is a more accurate reflection of cost causality.

d) The proposed blended OCR methodology would not apply to the Waasigan Project if Hydro One chose to undertake construction of the Project using a non-ECI-EPC methodology as part of the capital program.

[1] EB-2021-0110 – OEB Decision and Order, November 29, 2022. Pg 54 of the Settlement Proposal

OEB STAFF INTERROGATORY - 28

Reference:

1. Exhibit B-7-1, Pages 4-7
2. Atrium Economics Report, Exhibit B-7-1, Attachment 1
3. EB-2021-0110, Decision and Order, November 29, 2022, Settlement Proposal, October 24, 2022, Page 54

Preamble:

Hydro One has provided information regarding the apportionment of the Waasigan Project and risks in its application.

Ontario utilities previously reported under Canadian Generally Accepted Accounting Principles (CGAAP), which allowed for capitalization of indirect overheads. Since 2015, CGAAP is no longer applicable, and the majority of utilities have been required to adopt modified International Financial Reporting Standards (MIFRS) for regulatory reporting purposes. Under MIFRS, indirect overhead costs cannot be capitalized, and utilities were required to change their capitalization policies to align with MIFRS so that indirect overheads are no longer capitalized.[1] [2]

OEB staff also notes that there is uncertainty as to whether Hydro One will be required to adopt IFRS in the near future and therefore, no longer be able to capitalize indirect costs.

In the Hydro One JRAP settlement proposal, the parties agreed that Hydro One should estimate certain impacts of an initial transition from USGAAP to IFRS for regulatory purposes.

Interrogatory:

a) Please explain whether both Atrium Economics and Hydro One considered differences in its Overhead Capitalization Rate Methodology between IFRS and USGAAP in its review of such methodology. If so, please provide the assessment of the differences. If this is not the case, please explain.

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[1] Page 8 & 9 of Article 410 of Accounting Procedure's Handbook, effective January 1, 2012, states that property, plant and equipment include any costs that are directly attributable to bringing an asset to the location and condition necessary for it to be capable of operating in the manner intended by management. It also states that administration and general overhead costs is an example of costs that are not property plant and equipment.

[2] The OEB required mandatory changes to depreciation and capitalization policies aligned with IFRS as per its July 17, 2012 letter "Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013".

b) Please explain whether Hydro One would be receptive to performing an independent review that investigates alternate overhead capitalization methodologies used by other utilities in North America (as well as those of Hydro One's Ontario industry peers), including a blended capitalization rate methodology. If so, please provide Hydro One's proposal. Please also explain why the Atrium Economics Report filed in this application did not include such analysis.

c) Please explain why the Atrium Economics Report did not include any alternatives to that proposed for the Project in this application.

Response:

a) The Overhead Capitalization Rate Methodology proposed was developed using current approved capitalization approach of USGAAP, consistent with Hydro One's approved accounting standard.

b) Sections 2 and 3 of the Atrium Economics Report[3] discusses industry practices and is premised on the same guiding principles of cost allocation as the Black and Veach Report[4] filed in Hydro One's JRAP. Specifically, section 5.4.3 of the Black and Veatch Report reads:

> Based on Black & Veatch's expertise and experience in performing cost allocation studies the use of the Capital, Labour, and Revenue multi-factor allocation is in alignment with industry practices.

Furthermore, section 4.6 of the Black and Veach Report discusses the appropriateness of a blended or multi-factor allocation methodology, stating;

> The use of a multi-factor allocation to allocate costs that cannot be directly charged and for which a single cost allocation factor cannot be easily identified, is a broadly respected and common practice across the utility industry.

The allocation methodology, as described in the Black and Veach Report already considered methodologies used within the industry. Hydro One questions the merit of expending resources to effectively repeat this analysis.

c) The Overhead Capitalization Rate Methodology proposed in this Application was developed considering a significant portion of ECI-EPC projects will not rely as significantly on Hydro One's common corporate costs, as non-ECI-EPC projects will,

[3] Exhibit B, Tab 7, Schedule 1, Attachment 1.
[4] EB-2021-0110, Exhibit E, Tab 4, Schedule 8, Attachment 1.

to the extent which warranted a review of the amounts of overheads applied to this category of projects. As discussed in part b) above, the Atrium Economics Report is an extension of the industry and best practice analysis conducted initially as part of the development of the Blake and Veach Report[5].

[5] EB-2021-0110, Exhibit E, Tab 4, Schedule 8, Attachment 1.

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OEB STAFF INTERROGATORY - 29

Reference:

1. Exhibit B-7-1, Pages 1-16
2. Atrium Economics Report, Exhibit B-7-1, Attachment 1
3. EB-2019-0082, Draft Rate Order, Pages 25 & 26, May 28, 2020
4. EB-2021-0110, Decision and Order, November 29, 2022, Settlement Proposal, Page 86, footnote #70, October 24, 2022

Preamble:

OEB staff has questions regarding Hydro One's use of USGAAP and capitalization practices.

As noted earlier by OEB staff, the December 31, 2018 balance of $0.9 million in the Waasigan Transmission Line Deferral Account (Formerly NWBTL) was disposed in Hydro One's Hydro One Network Inc.'s 2020-2022 Transmission Custom IR Application.

OEB staff also notes that the Waasigan Transmission Line Deferral Account was the predecessor DVA to the ATP Account. As noted in the JRAP settlement proposal, "the Waasigan Transmission Line Tracking Deferral Account was subsequently closed and transferred to the ATP Account."

Interrogatory:

a) Under IFRS, administration and other general overhead costs are explicitly prohibited from capitalization. For 2019 to 2027 for the Project, please quantify, clarify, and explain whether the entire portion of common corporate costs would be considered administration and other general overhead costs, and therefore, prohibited from capitalization under IFRS.

b) Please clarify and explain whether Hydro One has other costs beyond common corporate costs that would qualify as administration and other general overhead costs that are prohibited to be capitalized under IFRS. If so, please quantify the annual amounts for 2019 to 2027 for the Project.

c) On a best-efforts basis, please explain, identify, and quantify indirect costs that would not be eligible for capitalization without regulatory approval as per USGAAP. This would include indirect overheads that Hydro One has capitalized under USGAAP Accounting Standards Codification (ASC) 980 for Regulated Operations, which otherwise would have been expensed under ASC 360 for Property Plant and Equipment had ASC 980 not been applied.

d) Regarding part c) of this interrogatory, please quantify the impact on the Project from 2019 to 2027.

e) Regarding part c) of this interrogatory, if this is a challenging undertaking for Hydro One, please explain whether Hydro One could perform this quantification and provide the results at the next rebasing application for the Project, on a best-efforts basis.

f) Please explain why Hydro One should be allowed to capitalize indirect overheads for the Waasigan Project just because it is under USGAAP.

g) Please outline the impact on the Project if the OEB does not allow Hydro One to capitalize indirect overheads as requested and recover such indirect overheads on a capitalized basis.

h) Please confirm that Hydro One would likely need to establish processes in advance of the transition date to IFRS to track the indirect overhead costs that are currently capitalized under USGAAP, but not permitted under IFRS. Please explain whether Hydro One would tract this impact in a DVA (e.g., Accounting Policy Changes Deferral Account or the ATP Account) and whether such a DVA should be established as part of this proceeding for the Project.

i) Please explain whether Hydro One's viewpoint is that relying on ASC 980 to capitalize indirect overheads is somewhat circular, as ASC 980 permits capitalization only where regulatory approval is probable.

Response:

a) Hydro One has approval from the Ontario Securities Commission ("OSC") to report under US GAAP for financial reporting purposes. Hydro One is required by securities legislation to adhere to US GAAP in its financial statements and cannot deviate from US GAAP for the recording of any transactions. As outlined below, Hydro One has explicit permission to use US GAAP for regulatory purposes by the OEB. The Company's audited financial statements are used as part of its regulatory filings it is required to adhere to all elements of US GAAP in its reporting.

The OEB approved[1] Hydro One's use of US GAAP for regulatory purposes for the 2023-2027 period. As per page 54 of the Settlement Proposal for Hydro One's s.78 revenue requirement application (Docket EB-2021-0110) the following was agreed;

[1] EB-2021-0110 – OEB Decision and Order, November 29, 2022. Pg 54 of the Settlement Proposal

> The Parties agree that Hydro One will continue to report under US GAAP for regulatory purposes for the rate period from 2023 to 2027 for each of Transmission and Distribution and revenue requirement should continue to be calculated under US GAAP for regulatory purposes.

The calculation of accounting variances between IFRS and US GAAP is irrelevant as the Project will be completed within the 2023-2027 period covered by Hydro One's s.78 revenue requirement application (Docket EB-2021-0110).

b) Quantifying prohibited costs under IFRS is irrelevant as Hydro One reports under US GAAP for both securities filings and regulatory purposes. Please refer to the response provided in part a), above.

c) Hydro One capitalizes indirect overheads in accordance with ASC 360, as allowable under US GAAP, and not through the application of ASC 980.

d) Refer to the response provided in part a), above.

e) Refer to the response provided in part a), above.

f) Refer to the response provided in part a), above.

g) Refer to the response provided in part a), above. The OEB has previously granted approval for Hydro One to apply US GAAP for regulatory purposes through to 2027, and the Project will be completed by the end of 2027.

h) Refer to part b), above.

i) Refer to the response provided in part c) above.

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OEB STAFF INTERROGATORY - 30

Reference:

1. Exhibit B-7-1, Tables 2-5, Pages 1-3
2. Exhibit B-7-1, Table 6, Page 7
3. Atrium Economics Report, Exhibit B-7-1, Attachment 1

Preamble:

Tables 2-5 shows the overhead costs for line and station for Phase 1 and Phase 2. Hydro One states that these costs are charged to capital projects through an overhead capitalization rate.

Table 6 tilted "Hydro One's Overhead Capitalization Rate for ECI-EPC Projects" shows the blended overhead capitalization rate. These rates are duplicated in the Atrium Economics Report's "Figure 3 – Blended OCR for ECI-EPC Contracted Projects".

Interrogatory:

a) Please confirm that the calculated overhead costs in Tables 2-5 are derived using the overhead capitalization rate in Table 6 titled "Hydro One's Overhead Capitalization Rate for ECI-EPC Projects". If this is not the case, please explain.

b) Please provide high level calculations used to derive the overhead costs in Tables 2-5.

c) Please explain and quantify the capitalized amounts in Tables 2-5 by cost category, including the capitalized amount ($) and the capitalized rate (%). Please also break down the overheads between direct overheads and indirect overheads. If any of this cannot be done by Hydro One, please explain.

d) Please provide a separate table showing the results of numbers presented in part c) of this interrogatory based on each of Hydro One's legacy method and Hydro One's proposed method for the Project, also including columns for the resulting variances in dollars and percentages. If any of this cannot be done by Hydro One, please explain.

e) Please confirm that the resulting variances in dollars and percentages shown in the response to part d) of this interrogatory are material. If these variances are not material, please explain why Hydro One is proposing a change to its overhead capitalization rate in this application.

f) For all of the requests made by OEB staff in parts a) to e) of this interrogatory, if Tables 2-5 do not cover the full period 2019 to 2027, please augment the evidence to cover this period.

Response:

a) As per Hydro One's response at Exhibit I, Tab 1, Schedule 27a), Hydro One implemented the adjusted overhead rate in Q3, 2023 and the impact of the refinement of the methodology was included in the project estimates disclosed in Tables 2 to 5 in Exhibit B, Tab 7, Schedule 1.

b) The calculation process used to derive the overhead costs in Tables 2-5 can be described as follows;

Project Overhead =

a. The Sum of [Materials, Labour, Equipment, Sundry and Contingencies] less pre-Q3 2023 expenditures) multiplied by the blended ECI-EPC Overhead rate,
Plus
b. Pre-Q3 2023 Project expenditures multiplied by standard overhead rate.

c) Below are Tables 2 to 5 from Exhibit B, Tab 7, Schedule 1, that illustrate that the Standard Overhead rate from Exhibit I, Tab 1, Schedule 21 part a) was utilized. Please note, there is a capitalized interest impact as well due to the higher expenditures.

d) Please refer to the table below.

Comparison of Table 2 - Phase 1 Line Cost

	As per B-07-01	Utilizing Standard Model Overhead from JRAP	$M Variance	% Variance
Materials	$ 108.6	$ 108.6	$ -	0.0%
Labour	$ 142.0	$ 142.0	$ -	0.0%
Equipment Rental & Contracto	$ 150.9	$ 150.9	$ -	0.0%
Sundry	$ 7.7	$ 7.7	$ -	0.0%
Contingency	$ 57.2	$ 57.2	$ -	0.0%
Overhead	$ 16.3	$ 37.9	$ 21.6	132.5%
Capitalized Interest	$ 28.7	$ 29.8	$ 1.1	3.8%
Real Estate	$ 34.7	$ 34.7	$ -	0.0%
Total Line Work	$ 546.1	$ 568.8	$ 22.7	4.2%

Comparison Table 3 - Phase 1 Station Cost

	As per B-07-01	Utilizing Standard Model Overhead from JRAP	Variance	
Materials	$ 56.4	$ 56.4	$ -	0.0%
Labour	$ 50.4	$ 50.4	$ -	0.0%
Equipment Rental & Contracto	$ 16.2	$ 16.2	$ -	0.0%
Sundry	$ 3.2	$ 3.2	$ -	0.0%
Contingency	$ 17.4	$ 17.4	$ -	0.0%
Overhead	$ 4.4	$ 12.2	$ 7.8	177.3%
Capitalized Interest	$ 7.0	$ 7.3	$ 0.3	4.3%
Real Estate	$ -	$ -	$ -	0.0%
Total Station Work	$ 155.0	$ 163.1	$ 8.1	5.2%

Comparison of Table 4 - Phase 2 Line Cost

	As per B-07-01	Utilizing Standard Model Overhead from JRAP	Variance	% Variance
Materials	$ 88.9	$ 88.9	$ -	0.0%
Labour	$ 122.5	$ 122.5	$ -	0.0%
Equipment Rental & Contracto	$ 125.1	$ 125.1	$ -	0.0%
Sundry	$ 6.8	$ 6.8	$ -	0.0%
Contingency	$ 42.7	$ 42.7	$ -	0.0%
Overhead	$ 13.5	$ 37.3	$ 23.8	176.3%
Capitalized Interest	$ 24.3	$ 25.9	$ 1.6	6.6%
Real Estate	$ 23.7	$ 23.7	$ -	0.0%
Total Line Work	$ 447.6	$ 472.9	$ 25.4	5.7%

Comparison Table 5 - Phase 2 Station Cost

	As per B-07-01	Utilizing Standard Model Overhead from JRAP	Variance	% Variance
Materials	$ 14.8	$ 14.8	$ -	0.0%
Labour	$ 18.7	$ 18.7	$ -	0.0%
Equipment Rental & Contracto	$ 6.4	$ 6.4	$ -	0.0%
Sundry	$ 1.3	$ 1.3	$ -	0.0%
Contingency	$ 6.3	$ 6.3	$ -	0.0%
Overhead	$ 1.4	$ 4.1	$ 2.7	192.9%
Capitalized Interest	$ 2.4	$ 2.4	$ -	0.0%
Real Estate	$ -	$ -	$ -	0.0%
Total Station Work	$ 51.3	$ 54.0	$ 2.7	5.3%

e) Hydro One's position is that the variances are material, and the proposed ECI-EPC overhead methodology, provides a more accurate reflection of the total effort required by Hydro One on those ECI-EPC activities. Utilizing the standard delivery model overhead would increase the total cost estimate of the project by approximately $58.9M, or 4.9%. However, this is only a portion of the impact that Hydro One expects the methodology to provide. As noted in Hydro One's response to Exhibit I, Tab 1, Schedule 22 part a), Hydro One will be using the ECI-EPC methodology going forward to deliver a portfolio of significant transmission system expansion projects, estimated [REDACTED] than $[REDACTED] until 2027 and continuing to [REDACTED] in future years. Utilizing the standard delivery model overhead instead of the ECI-EPC, for these types of projects where the ECI-EPC model will be used, would result in an increase to those projects' expenditures in the portfolio of approximately $[REDACTED] to $[REDACTED] of which the Waasigan portion is $58.9M as per d) above. This value will increase even further than this estimate when Hydro One is directed to begin approvals and construction of other projects that have been included in an Order in Council, such as Longwood by Lakeshore Second Single 500kV Circuit, which is designated to Hydro One to design and seek approvals for once the need date from the IESO is provided.

f) The costs presented in Exhibit B, Tab 7, Schedule 1 are the baseline from that which Hydro One adjusted the Project costs and provided the responses above. Those estimates include total Project costs from 2019 through to the forecast Project completion and in-service date.

KURT KRAUSE INTERROGATORY - 01

Preamble:

Lithium prices have plunged 30.21 % this year. General consensus among commodity traders in this field expect a decline of roughly the same amount or more in lithium prices next year. Global prices are not expected to recover until at least 2028 due to the oversupply and hoarding of these metals by Chinese producers who are facing a collapse in demand in EV products.

Interrogatory:

a) The line proposed to Atikoken was to enhance power delivery to mining ventures for this and other minerals. Why is the ratepayer expected to subsidize mines which are clearly not viable as standalone economic ventures until at least 2040 if ever?

b) The second line proposed by the NOTL going directly to Dryden would lower the cost of the project proposed by Hydro One substantially. Alternative lines offer more economic benefits and less environmental impact. The studies carried out by Hydro One were rushed, incoherent, and clearly lacked professional analysis. Why has Hydro one not looked more closely at alternatives and worked with impacted stake holders as an honest broker and come up with viable alternative solutions?

c) Hydro One was offered a proposal for a green technology solutions by our Group of Companies to maintain the current and proposed Right of ways. Innovative low-cost solutions for power generation and foliage maintenance were offered to Hydro One in line with indigenous values. If Hydro One is truly wanting to work with stakeholders why does it refuse to even contemplate money saving green solutions?

Response:

a) Please see the '*Waasigan Transmission Line Project: Need, Alternatives, and Recommendation*' (the "Report") located at Exhibit B, Tab 3, Schedule 1, Attachment 9. The IESO has further advised Hydro One that the Waasigan Project was recommended by the IESO to address forecast electricity demand growth in the west of Thunder Bay Region (the "Region") resulting from residential and commercial development, the connection of off-grid communities to the grid, and mining and non-mining related industrial growth. While new and expanded mining developments are the most significant contributors to this forecast demand growth, the majority of that development relates to gold mining operations, not lithium. Of the 12 mines included in the IESO's load growth forecast, only two are associated with lithium mining, with the remaining 10 related to gold. Combined, these two lithium projects represent only a small proportion of the Region's forecast demand growth and are only captured in

the IESO's '*Strong Growth*'[1] forecast scenario as they are at an early stage of development.

The IESO Report further states that if even one of the larger project developments proceeds and seeks grid connection in the Region, there will be an immediate need for additional supply capacity[2]. The IESO has confirmed that even if the two known lithium mines do not proceed, the IESO's recommendation that the Waasigan Project is needed would not change as the majority of the forecast growth, and in particular the near-term growth driving the urgency of the need, is not tied to lithium mining.

The IESO further clarifies in this response that the Waasigan Project has not been recommended to provide supply to any particular customer or set of customers. Rather, it is a bulk electricity system reinforcement which will provide broad system benefits to the entire Region which include capacity to supply forecast demand growth. Individual mines will still be responsible for the cost of their connection facilities as stipulated in the Transmission System Code.

b) Please refer to Exhibit I, Tab 1, Schedule 5, part a).

c) Hydro One expects to operate and maintain the Project as part of its overall fleet of transmission facilities. From time-to-time Hydro One receives and reviews proposals for the maintenance of assets and will continue to do so once the Project is completed and placed into service. Hydro One's vegetation management for the Project will not likely require substantial maintenance costs immediately following construction given clearing activities that are required to allow construction to proceed. Novel approaches to vegetation management that utilize cost efficient and effective means while maintaining objectives of safety and reliability are areas of ongoing interest to Hydro One. Procurement opportunities are often made available during operations to solicit proposals of this sort.

[1] The Strong Growth scenario, is one of four developed by the IESO, as referenced multiple times with the IESO's is defined by the IESO's '*Waasigan Transmission Line Project: Need, Alternatives, and Recommendation*', as included in the Application at Exhibit B, Tab 3, Schedule 1, Attachment 9.
[2] Exhibit B, Tab 3, Schedule 1, Attachment 9, Pg. 18.

NEIGHBOURS ON THE LINE (NOTL) INTERROGATORY - 01

Preamble:

We understand that the OEB requested that any additional information from Neighbours on the Line (NOTL) was to be submitted by December 5, 2023. The following outlines our concerns regarding costs and who will be responsible for those costs.

The biggest question we have is: Does Hydro One internally pay for any of the costs for the transmission line or is it passed on to Hydro One consumers?

It was stated by Hydro One in our local media that we as customers will be paying for this transmission line. Therefore, we have every right to know that Hydro One is being transparent with their costs.

Interrogatory:

a) Who pays for all the expenses for Hydro One Toronto personnel to attend the numerous meetings and presentations held in Kaministiquia? Which at times we felt were excessive.

b) Who pays for all their land men/contractors that have been pushing for the landowners to sell or agreeing to land access?

c) Note that there is 90 km of current mining claims, in Phase One, that would be directly on the new line right of way, some being high valued at this time. Hydro One did not reveal or did not know about these until NOTL presented them with a map outlining all these claims. Who pays for the settlement and the work that will be involved to settle with the mining claim holders?

d) Who pays for the human impact and the destruction of the community?

   There has been so many residents experiencing mental and physical stress. Will they be compensated?

   For those that have signed and agreed with Hydro One either did not care, wanted to sell anyways, do not live on their property, or were just bullied into an agreement, i.e., take what Hydro One is offering now, or you will get so much less later.

e) Regarding the NOTL first alternate route that was presented to Hydro One, we knew that their numbers of their evaluation were not transparent and swayed in their favour.

When we added up the numbers that they had on their evaluation, the true result was that their route and our alternate route where close in numbers.
Because of this example of Hydro One not being transparent and not recognizing the true facts, will their answers to your questions outlined in Procedural Order No. 2 be accurate. That is our biggest concern.

f) Hydro One had a news conference in Thunder Bay and clearly stated that we as consumers will be paying for this Waasigan Transmission Line. So are we paying to have our property and community destroyed, trees cut down, watersheds impacted, houses demolished, and visual destruction. This will be forever, in a community that has been established for over a hundred years.

This does not have to happen. There is an alternate route that would be cost effective and cheaper, i.e., the route proposed by NOTL.

Is human value of no concern?

g) What about their partners involved in this project? Will they be liable for anything? What will they cost us, as we, the consumers, will be paying for the line?

h) We pay the taxes on our property which includes Hydro One's existing easement. Now with a second planned easement, we will continue to pay taxes on land used by Hydro One and their partners.

If other companies, i.e., fiber optics, use the line as well, are they paying Hydro One for that use, and we do not get anything?

i) NOTL feels that this whole project has been lacking in transparency. A good example of this is the fact that we as Unincorporated Townships were not recognized in the Terms of Reference. Why is that?

j) This new line, just as the existing line, will go through all unincorporated townships from Shuniah to Atikokan. Hydro One and partners need to explain and justify why this project should even happen as proposed.

Response:

a) Costs associated with engagement and consultation are included as part of the total Project cost forecast presented in Exhibit B, Tab 7, Schedule 1. Recovery of actual incurred Project costs are a matter of future rate setting (i.e., revenue requirement) proceedings and will be assessed for recovery by the OEB.

b) Costs associated with land acquisitions are included as part of the total cost forecast presented in Exhibit B, Tab 7, Schedule 1. Refer to part a) above regarding rate recovery of these costs.

c) The Ministry of Natural Resources and Forestry[1] ("MNRF") requires prospective users of Crown lands to obtain consents from underlying (i.e., existing) unpatented mining claim holders before granting occupational authority over the required lands. Hydro One is carrying out this process as part of its Crown lands permitting program. Costs associated with mining claim consents are included as part of the total Project cost forecast presented in Exhibit B, Tab 7, Schedule 1. Refer to part a) above regarding rate recovery of these costs.

d) Socio-economic effects are addressed in Hydro One's Environmental Assessment ("EA")[2] for this Project. Please refer to Section 7.0 of the EA which presents detailed results of the assessment of effects to people and communities and identifies measures to mitigate negative effects. While Hydro One appreciates that major linear infrastructure developments may impact communities in varying degrees and ways, mitigation of these impacts is generally addressed by Hydro One adopting well understood utility construction and operation practices so that transmission facilities may safely and reliably deliver electricity services across Ontario to its citizens and ratepayers. The OEB's Procedural Order No. 1 issued to all parties participating in this proceeding expressly states issues concerning environmental matters and Indigenous consultation are not relevant to this proceeding unless demonstrated to relate to price, reliability and quality of electricity service.

e) Hydro One declines to respond to this statement as no question or request for information is provided. The topic of this statement appears to relate to route evaluation and selection. These are matters addressed in Hydro One's Environmental Assessment ("EA")[3]. Please refer to Section 2.0 of the EA which presents detailed results of the route evaluation. The OEB's Procedural Order No. 1 issued to all parties participating in this proceeding expressly states issues concerning environmental matters and Indigenous consultation are not relevant to this proceeding unless demonstrated to relate to price, reliability and quality of electricity service.

f) As the question pertains to the EA, please refer to part d) and e) above. As the question pertains to rate recovery of the Project costs, please refer to part a) above.

[1] Now know as the Ministry of Energy, Northern Development and Mines.
[2] www.hydroone.com/about/corporate-information/major-projects/waasigan/project-approvals
[3] www.hydroone.com/about/corporate-information/major-projects/waasigan/project-approvals

g) As the question pertains to the limited partnership agreement, please refer to Exhibit I, Tab 1, Schedule 2, part a). As owners in the Project, partners face common risks associated with facility and asset ownership. Hydro One is responsible for risks during construction of the Project.

h) The terms included in the forms of agreements are set out in Exhibits E, Tab 1, Schedule 1, and contemplate landowners being able to continue to use their lands as long as that use is compatible with the agreements. Therefore, landowners would be responsible to pay their own property taxes. The costs for Hydro One acquiring and holding the property rights required for the Project have been included in the Project cost forecast, as presented in Exhibit B, Tab 7, Schedule 1. The use of the compensation received within each agreement is at the discretion of the respective landowner. Per Hydro One's Land Acquisition Compensation Principles for the Waasigan Transmission Line Project[4], impacted landowners have the option to have Hydro One acquire corridor lands in fee simple. If this option is elected, property taxes for the subject corridor lands would become the responsibility of Hydro One.

For any income that is generated through agreements that are non-transmission related, such as companies offering fiber optics, or other telecommunication services, these revenues would be considered 'external revenue', and would be treated in a revenue requirement application consistent with OEB policy.

i) The process completed to identify alternative routes to be evaluated, as contained within the Environmental Assessment ("EA")[5], is detailed in the Amended Terms of Reference[6] approved by the Ministry of the Environment, Conservation and Parks. In addition, please refer to Section 2.0 of the EA which presents detailed results of the route evaluation. The OEB's Procedural Order No. 1 issued to all parties participating in this proceeding expressly states issues concerning environmental matters and Indigenous consultation are not relevant to this proceeding unless demonstrated to relate to price, reliability and quality of electricity service.

j) In response to the part of the question that relates to Project need, please refer to Exhibit I, Tab 2, Schedule 1 response a) and Application evidence Exhibit B, Tab 3, Schedule 1. With respect to the part of the question that appears to relate to the route evaluation and selection, these are matters addressed in Hydro One's Environmental Assessment ("EA"). Please refer to Section 2.0 of the EA which presents detailed

[4] Provided at Exhibit I, Tab 1, Schedule 15, Attachment 1.
[5] www.hydroone.com/about/corporate-information/major-projects/waasigan/project-approvals
[6] https://www.hydroone.com/abouthydroone/CorporateInformation/majorprojects/Waasigan/Documents/final-ea-report/appendices/Appendix_1.0-A%20Terms%20of%20Reference.pdf

results of the route evaluation. Further, the OEB's Procedural Order No. 1 issued to all parties participating in this proceeding expressly states issues concerning environmental matters and Indigenous consultation are not relevant to this proceeding unless demonstrated to relate to price, reliability and quality of electricity service.

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MÉTIS NATION OF ONTARIO (MNO) INTERROGATORY - 01

Reference:

1. EB-2023-0198 – Hydro One Networks Inc. Leave to Construct Application – Waasigan Project – Application and Evidence, Exhibit B-1-1, Page 4, Lines 21-31.

Interrogatory:

a) Provide all correspondence between Hydro One and the Ministry of Environment, Conservation and Parks ("MECP"), the Ministry of Natural Resources and Forestry ("MNRF"), the IESO, and any other regulators related to the Waasigan Project.

Response:

a) Hydro One declines to provide the requested information. No explanation is provided as to why the production of "all correspondence between Hydro One and MECP, the Ministry of Natural Resources and Forestry, the IESO and any other regulators related to the Waasigan Project" is relevant to this proceeding.

The Project is subject to an Environmental Assessment requiring approval from the MECP, which included robust consultation in fulfillment of both the requirements of the *Environmental Assessment Act* as well as the Crown's duty to consult (for which procedural aspects were delegated to Hydro One). However, these matters fall outside the scope of this proceeding as was determined in the Board's Procedural Order No. 1.

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MÉTIS NATION OF ONTARIO (MNO) INTERROGATORY - 02

Reference:

1. EB-2023-0198 – Hydro One Networks Inc. Leave to Construct Application – Waasigan Project – Application and Evidence, Exhibit B-7-1, Pages 7-8, Lines and 18-27. 1-11; Exhibit B-11-1, (Project Schedule).

Interrogatory:

a) Provide a list of outstanding environmental approvals and permits required to construct the Waasigan Project and Hydro One's understanding of the process to obtain these permits, including the need for consultation with Indigenous communities.

b) Explain the probability and implications of missing anticipated approval dates for outstanding environmental approvals and permits.

c) Explain in detail Hydro One's completed archaeological work, and plans for future archaeological work, including plans for engagement and participation of Indigenous communities.

d) Confirm that risks associated with engagement and consultation with Indigenous communities have not been included in Hydro One's allowance for contingency.
   a. If not, explain in detail why not.
   b. Provide an estimate of costs associated with these risks.

Response:

a) Hydro One declines to provide the requested information. No explanation is provided as to why the production of "outstanding environmental approvals and permits required to construct the Waasigan Project and Hydro One's understanding of the process to obtain these permits, including the need for consultation with Indigenous communities" is relevant to this proceeding.

   The Project is subject to an Environmental Assessment requiring approval from the Ministry of the Environment, Conservation and Parks ("MECP"), which included robust consultation in fulfillment of both the requirements of the *Environmental Assessment Act* as well as the Crown's duty to consult (for which procedural aspects were delegated to Hydro One). However, these matters fall outside the scope of this proceeding as was determined in the Board's Procedural Order No. 1

b) Hydro One cannot speculate on the probability of regulator's timelines to decide upon environmental approvals and permits. Hydro One works closely with regulators to

understand the requirements and timelines associated with approvals and permits. This information informs the Project Schedule, which is presented in Exhibit B, Tab 11, Schedule 1. Should approval and permit timelines extend beyond those that are anticipated, the Project Schedule would be adjusted accordingly. Costs associated with reasonable schedule risk are included in the Project's contingency cost forecast.

c) Hydro One declines to respond to this request. Completed and planned archeological work, and consultations with Indigenous communities relating to engagement and participation in those matters are beyond the scope of this proceeding and are addressed as part of the processes established for environmental approvals required for this Project. Costs associated with undertaking archaeological work for the Project, including any related engagement and consultation is part of the Project cost forecasts presented to the OEB in this application.

   The Project is subject to an Environmental Assessment requiring approval from the MECP, which included robust consultation in fulfillment of both the requirements of the *Environmental Assessment Act* as well as the Crown's duty to consult (for which procedural aspects were delegated to Hydro One). However, these matters fall outside the scope of this proceeding as was determined in the Board's Procedural Order No. 1

d) Project cost risks (including in-service timing and cost increases exceeding forecast levels) arising from Indigenous community engagement and consultation forms part of the contingency cost forecast. As per the response at Exhibit I, Tab 1, Schedule 7, the contingency is not a funded liability of all risk items (such as explicit delays arising from Indigenous community engagement and consultations) but rather it is a probabilistic amount based on Hydro One's assessment of the likelihood of occurrence.
   a. N/A.
   b. Please refer to Exhibit I, Tab 1, Schedule 7.

MÉTIS NATION OF ONTARIO (MNO) INTERROGATORY - 03

Reference:

1. EB-2023-0198 – Hydro One Networks Inc. Leave to Construct Application – Waasigan Project – Application and Evidence, Exhibit B-1-1, Pages 2-3, Lines 17-31, 6-9.

Interrogatory:

a) Describe in detail Hydro One's "extensive economic discussions with impacted Indigenous communities."

b) Provide copies of all correspondence and documents relating to seeking or agreement with Indigenous communities on economic participation.

c) Provide an update on the formation and structuring of the Gwayakocchigewin Limited Partnership ("GLP").

d) Identify the amount of costs associated with ownership of transmission facilities by the GLP and confirm whether these costs are included in Hydro One's cost estimate for the Waasigan Transmission Line Project.

Response:

a) Please refer to Exhibit B, Tab 1, Schedule 1, Pg. 2 at paragraphs 5 and 6. Hydro One initiated an Early Contractor Involvement ("ECI") model for the Waasigan Transmission Line Project in February 2021. To support Hydro One's commitments to maximize Indigenous economic participation, two EPC firms were engaged to begin discussions with impacted Indigenous communities on the opportunities for local people and businesses to participate in the project through training, employment, procurement, and subcontracting. Indigenous communities were supported and encouraged to participate in the ECI process to impact the inclusion of new economic opportunities for Indigenous people, businesses, and communities in the development of the Waasigan Transmission Line. Economic discussions with Indigenous communities impacted by the Project continue to be ongoing and generally relate to the topics of equity participation, commercial structuring of the ownership of the Project following in-service timing, and construction employment and procurement processes including opportunities for Indigenous people and businesses that have requisite skills and/or the necessary resources to participate in such economic opportunities.

b) Hydro One declines to provide the requested information as this information is not relevant to the issues of price, reliability, and quality of electricity service. Formation and structuring of Indigenous communities interested in making economic investments

in the Project are ongoing matters of commercial discussion with Hydro One and are not expected to be resolved prior to in-servicing of the Project. Economic participation, formation, structuring, and other potential costs associated with the ownership of transmission facilities by the Gwayakocchigewin Limited Partnership ("GLP") are not matters within Hydro One's purview as Hydro One is not contemplated to be a part of this Partnership. Since these types of costs have not been included in Hydro One's cost estimate to construct and operate the Waasigan Transmission Line Project, Hydro One declines to speculate on whether or how costs of changes in future Project ownership would be considered by the Board in either a future asset transfer or future rates revenue requirement proceeding.

c) Please refer to part b), above.

d) Please refer to part b), above.

MÉTIS NATION OF ONTARIO (MNO) INTERROGATORY - 04

Reference:

1. EB-2023-0198 – Hydro One Networks Inc. Leave to Construct Application – Waasigan Project – Application and Evidence, Exhibit B-6-1, Page 2, Lines 15-26.

Interrogatory:

a) Explain in detail the employment, training, and business opportunities that the Project will bring to Indigenous communities and businesses during construction, operation, and maintenance of the Project. Provide all documents, correspondence, and analyses related to the same.

b) Explain in detail the work Hydro One has done with Indigenous communities in the region to understand their interests and aspirations in the future of Ontario's energy grid. Provide all documents, correspondence, and analyses related to the same.

c) Beyond the opportunity to invest in a 50 per cent equity stake in the transmission line components of the Project, explain in detail how the Project will provide innovative and lasting benefits to Indigenous communities in procurement, employment, economic benefits, and investment opportunities. Provide all documents, correspondence, and analyses related to the same.

Response:

a) Discussions and commercial negotiations with Indigenous communities regarding employment, training, and business opportunities for the Waasigan Transmission Line Project have been facilitated through the Early Contractor Involvement ("ECI") process and are ongoing with those communities who have chosen to actively participate in the process. In 2022, Hydro One committed to increasing Indigenous procurement spend to 5% of the company's purchases of materials and services by 2026.

For further information on Hydro One's policies that seek to maximize Indigenous economic participation, please refer to the Hydro One Indigenous Relations Policy that can be found at: https://www.hydroone.com/abouthydroone/indigenousrelations/Documents/Hydro%20One%20Indigenous%20Relations%20Policy.pdf and Hydro One Purchasing Policy and Principles that are publicly available at: https://www.hydroone.com/about/indigenous-relations/business-opportunities

b) Hydro One declines to respond to this information request. Details of the work Hydro One has done with Indigenous communities in the region to understand their interests

and aspirations in the future of Ontario's energy grid, are matters well beyond the scope of the Issues List 1 for this Proceeding.

c) Please refer to the responses in part a), above.

[1] The Issues List is located in Schedule B of the OEB's Procedural Order No.1 (dated November 10, 2023) for EB-2023-0198.

MÉTIS NATION OF ONTARIO (MNO) INTERROGATORY - 05

Reference:

1. EB-2023-0198 – Hydro One Networks Inc. Leave to Construct Application – Waasigan Project – Application and Evidence, Exhibit B-7-1, Pages 4-5, Lines 22-28, 1-2.

Interrogatory:

a) Describe in detail Hydro One's initiatives involving Indigenous communities to deliver transmission line projects in a cost-effective, efficient, and timely manner. Provide all documents and analyses including working documents regarding the same.

b) Describe in detail Hydro One's policy to provide equity opportunities to First Nations for greenfield transmission line projects and any other similar policies. Provide all documents and analyses including working documents regarding the same.

Response:

a) Delivery of the Project's construction in a cost-effective, efficient, and timely manner are matters within Hydro One's purview. Through ongoing consultations and engagement with Indigenous communities and others, Hydro One plans to mitigate Project risks, such as regulatory delays and construction cost overruns, by keeping communities up to date on Project status, including Indigenous communities on procurement opportunities, and ensuring Indigenous communities are aware and are consulted on Project specific routing and construction techniques. Indigenous community consultations are outside the scope of this proceeding, as discussed further in Exhibit I, Tab 4, Schedule 1, and as such Hydro One declines to provide the requested documents, analysis and working documents regarding these ongoing initiatives. Absent a clearer understanding as to how and why this information is relevant to this proceeding, Hydro One submits expending the resources that would be necessary to fulfill this request and over the duration of the Project's development would result in regulatory inefficiencies, unnecessary delays and incremental costs and provide the Board with little or no benefit in its consideration of the relief sought in this Application.

b) A description of Hydro One's equity partnership model to provide equity opportunities to First Nations for greenfield transmission line projects is in the public domain, however its content and subject-matter are not relevant to the scope of the issues as set out in the OEB's Procedural Order No.1[1]. Hydro One therefore declines to provide the information requested in this Interrogatory.

[1] https://www.rds.oeb.ca/CMWebDrawer/Record/822389/File/document

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MÉTIS NATION OF ONTARIO (MNO) INTERROGATORY - 06

Reference:

1. EB-2023-0198 – Hydro One Networks Inc. Leave to Construct Application – Waasigan Project – Application and Evidence, Exhibit B-7-1, Pages 1-4.

Interrogatory:

a) Explain in detail how continued engagement with Indigenous communities is reflected in Hydro One's cost estimate for the Waasigan Project, including through the construction and operation phases.

   a. If not reflected, confirm Hydro One's intentions for continued engagement and participation of Indigenous communities, and how these costs will be accounted for in the future.

b) Provide a plan for Indigenous engagement with reference to the Project Schedule at Exhibit B, Tab 11, Schedule 1.

Response:

a) The costs of Indigenous community engagement during the construction phase of the Project are reflected in the Project's forecast costs, specifically in Tables 1 and 2 in Exhibit B, Tab 7, Schedule 1. Costs associated with ongoing Indigenous community engagement following in-servicing of the Project are matters that would be determined in future OEB revenue requirement proceedings and therefore are beyond the scope of this proceeding.

b) Indigenous engagement is discussed in detail in the Environmental Assessment (EA) and is beyond the scope of this proceeding. For additional context, the schedule provided at Exhibit B, Tab 11, Schedule 1 starts as of the filing of the leave to construct application and documents the project milestones through the execution phase of the Project. Indigenous engagement plans predate this schedule as documented in the EA and continue well beyond the in-servicing of the Project as documented in response to sub-part a) of this interrogatory.

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MÉTIS NATION OF ONTARIO (MNO) INTERROGATORY - 07

Reference:

1. EB-2023-0198 – Hydro One Networks Inc. Leave to Construct Application – Waasigan Project – Application and Evidence, Exhibit C-1-1, Pages 1-3.

Interrogatory:

a) Provide an up-to-date and detailed Project schedule for Hydro One's plans to construct the Waasigan Project through the Campus Lake Conservation Reserve and the Turtle River-White Otter Lake Provincial Park including required approvals and permits, consultation requirements including with Indigenous communities, all risks and possible delays associated with each permit or requirement, and an explanation of the potential impact to the in-service date and Project costs if each approval or other requirement is missed by six months or more.

Response:

a) Detailed Project construction schedules, such as timing of construction through a sub-route component, such as that through the Campus Lake Conservation Reserve and Turtle River-White Otter Provincial Park, have not yet been developed as details required for this type of information is dependent upon obtaining all the necessary regulatory and environmental approvals. Delays in obtaining these approvals, or other risks (e.g., supply chain procurement risks, pandemic risks, the ability to procure long-lead items, approval conditions that cause unforeseen changes to construction methods and other extraneous risks such as wildfires) could ultimately impact the specific timing of constructions activities along the specific construction corridors. To the extent that material unforeseen events do occur, such as those described above, and do cause material impacts to Project cost forecasts (as contained in Exhibit B, Tab 7, Schedule 1) and the Project's schedule (as contained in Exhibit B, Tab 11, Schedule 1) Hydro One would expect to update the Board with information pertaining to those circumstances and provide a revised schedule and impact to the Project's costs, consistent with the OEB's Conditions of Approval.

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MÉTIS NATION OF ONTARIO (MNO) INTERROGATORY - 08

Reference:

1. EB-2023-0198 – Hydro One Networks Inc. Leave to Construct Application – Waasigan Project – Application and Evidence, Exhibit E-1-1, Page 2-5.

Interrogatory:

a) Describe in detail Hydro One's discussions with Indigenous communities with respect to use of Crown lands for the Waasigan Project. Provide all documents and correspondence with respect to the same.

b) Explain the process for obtaining land use permits for Crown lands including with respect to obligations for consultation.

c) Explain in detail Hydro One's Consultation Plan. Provide all documents and correspondence with Indigenous communities and the Crown relating to the same.

Response:

a) Hydro One has consulted with Indigenous communities over several years regarding the routing of the Waasigan Transmission Line. Consultations followed several phases of routing discussions, including: i) Alternative route consultations to receive input into the development of alternative routes and input on the proposed alternative routes themselves; ii) Preliminary preferred route consultations to receive input on a proposed preliminary preferred route; and iii) Preferred route consultations to discuss the project's final preferred route. All phases of consultations were designed with an intent of understanding significant concerns with routing and included Community Information Centres, Open Houses, meetings, workshops among other engagement opportunities, as requested by Indigenous communities to meet their specific needs. Documentation and correspondence with respect to route consultations is contained within the Record of Consultation for the Environmental Assessment[1] and considered to be beyond the scope of this proceeding.

b) Extensive consultation has been completed with permitting agencies throughout the Environmental Assessment ("EA") process for the Waasigan Project in order to satisfy the requirements of the *Environmental Assessment Act,* including satisfying regulatory requirements of the Ministry of Natural Resources and Forestry ("MNRF"), Class Environmental Assessment for Provincial Parks and Conservation Reserves and the MNRF Class Environmental Assessment for Resource Stewardship and Facility

[1] www.hydroone.com/about/corporate-information/major-projects/waasigan/project-approvals

Development Projects. Occupational authority, in the form of a Land Use Permit, is granted by MNRF, with exception of conservation reserves and provincial parks, which involves Ontario Parks/Ministry of the Environment, Conservation and Parks. Hydro One will undertake the necessary applications to the applicable Ministries for the necessary Land Use Permits. Alongside the Ministerial review, a prospective Permitee is required to engage existing occupiers of Crown lands (claimholders, leaseholders, licencees, etc.). The outcome of both the review and engagement enables the ultimate issuance of the Land Use Permit.

c) Please refer to Exhibit E, Tab 1, Schedule 1, Pg. 2 for a general description of Hydro One's Indigenous Consultation Plan. Hydro One declines to provide the requested information as it is beyond the scope of the issues established in Procedural Order No. 1[2]. Please refer to Hydro One's Response to Exhibit I, Tab 4, Schedule 1.

[2] https://www.rds.oeb.ca/CMWebDrawer/Record/822389/File/document

MÉTIS NATION OF ONTARIO (MNO) INTERROGATORY - 09

Reference:

1. EB-2023-0198 – Hydro One Networks Inc. Leave to Construct Application – Waasigan Project – Application and Evidence, Exhibit C-1-1, Pages 1-3.

Interrogatory:

a) Describe in detail how Hydro One considered route alternatives based on concerns expressed by groups other than the Kaministiquia community, including Indigenous communities.

b) Provide copies of all correspondence and documents between Hydro One and Indigenous communities with respect to route options, analysis, and selection.

c) Explain in detail the decision to route through the Campus Lake Conservation Reserve and the Turtle River-White Otter Lake Provincial Park, how this was balanced against other factors considered in Hydro One's route analysis.

d) Provide a detailed analysis of costs associated with routing through the Campus Lake Conservation Reserve and the Turtle River-White Otter Lake Provincial Park relative to alternatives.

e) Provide all documents and correspondence between Hydro One and MECP and MNRF related to routing, including with respect to routing through the Campus Lake Conservation Reserve and the Turtle River-White Otter Lake Provincial Park.

f) Provide copies of all correspondence received by Hydro One expressing concerns with or opposing Hydro One's proposed routing through the Campus Lake Conservation Reserve and the Turtle River-White Otter Lake Provincial Park.

g) Provide copies of all correspondence and documents received by Hydro One expressing concerns with or opposing the use of unoccupied Crown land for the Project.

h) Provide copies of all documents and correspondence received by Hydro One expressing concerns with or opposing routes in proximity to First Nation reserves.

i) Provide copies of all documents and correspondence received by Hydro One expressing concerns or opposing Hydro One's preferred route.

j) Provide all documents and correspondence between Hydro One and IESO related to route alternatives and analysis.

Response:

a) Route evaluation and selection are matters addressed in Hydro One's Environmental Assessment ("EA")[1]. Please refer to Section 2.0 of the EA which presents detailed results of the route evaluation. As these matters have been determined to fall outside the scope of this proceeding, Hydro One declines to respond further to this Interrogatory Request. Please refer to Hydro One's Response to MNO Interrogatory 1, (i.e. Exhibit I, Tab 4, Schedule 1.)

b) Please refer to response a) above, as well as Exhibit I, Tab 4, Schedule 8, part c).

c) Please refer to response a) above. Alternative routes were identified in the approved Amended Terms of Reference[2]. For the section of the Project from Atikokan to Dryden, all alternative routes crossed Turtle River-White Otter Lake Provincial Park (Routes 3A, 3B, and 3C) and one also crossed Campus Lake Conservation Reserve (Route 3A). An evaluation was completed in the EA to identify an overall preferred route for the Project by comparing these route alternatives and included consideration of the area (hectares) that crossed provincial parks and conservation reserves under both the natural and socio-economic environment themes. Overall, the preferred route best balanced the themes that were considered, provided a viable solution using proven technologies, was technically feasible, and was consistent with provincial government objectives and direction.

d) Alternative routes were identified in the approved Amended Terms of Reference[3]. A multi-criteria analysis tool was used in the EA to evaluate Project alternatives across four key themes relevant to the Project, including technical and cost considerations. Costs used in the alternative route evaluation included estimated construction Project cost and estimated yearly operation cost. All forecast costs associated with the construction of the preferred route are included in the Project costs forecast (see Exhibit B, Tab 7, Schedule 1). Detailed forecast costs of specific segments of the route are not available, nor feasible to produce. The preferred route identified, best balanced the four themes that were considered, provided a viable solution using

[1] www.hydroone.com/about/corporate-information/major-projects/waasigan/project-approvals.
[2] Hydro One's Project Terms of Reference; https://www.hydroone.com/abouthydroone/CorporateInformation/majorprojects/Waasigan/Documents/final-ea-report/appendices/Appendix_1.0-A%20Terms%20of%20Reference.pdf
[3] Hydro One's Project Terms of Reference; https://www.hydroone.com/abouthydroone/CorporateInformation/majorprojects/Waasigan/Documents/final-ea-report/appendices/Appendix_1.0-A%20Terms%20of%20Reference.pdf

proven technologies, was technically feasible, and was consistent with provincial government priorities and direction.

The Project footprint proposes to cross Turtle River-White Otter Provincial Park, Campus Lake Conservation Reserve and an access road through Quetico Provincial Park where there were no other suitable options. For example, it is not possible to completely avoid crossing Turtle River-White Otter Provincial Park given the park's large geographic extent. The portions of the right-of-way and types of Project components that will be located in these protected areas were selected as there were no other reasonable alternative routes. Consistent with the broad definition of "Environment" within the *Environmental Assessment Act*, and the need of the EA to consider and balance multiple evaluation categories and criteria across the alternative routes, costs were not the only consideration when selecting a preferred route – a segment of which includes the described crossing of one provincial park and one conservation reserve.

e) Please refer to response a), above.

f) Please refer to response a), above.

g) Please refer to response a), above.

h) Please refer to response a), above.

i) Please refer to response a), above.

j) Please refer to response a), above.

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LARRY RICHARD INTERROGATORY - 01

Preamble:

Issues 2.1

In January 2023 Hydro One released a preliminary preferred Project route for the Waasigan Transmission Line. To our surprise, it did not include the decommissioned Steep Rock Mine brownfield corridor. Section 2.2 of the Environmental Assessment states the considerations used to develop the chosen route and evaluates several alternative route options. Despite evaluating alternatives in other areas along the proposed alignment, no alternative route was considered between Shabaqua and Atikokan. The Steep Rock Mine brownfield corridor is a decommissioned 30-metre-wide corridor that runs from Thunder Bay to Atikokan. Hydro One requires a 46-metre-wide swath to construct the 230 kV Waasigan corridor. As such an additional 16 metres of land is needed for the Waasigan Transmission Line alignment. The EA further states that crossovers cause reliability issues with the IESO, although there is no further explanation of how or to what extent crossovers cause reliability issues. Given that it costs much less to deforest a 16-metre-wide stretch of forest than it would to deforest a 46-metre-wide stretch of forest, the following questions are designed to demonstrate that the Steep Rock Mine corridor is the most cost-effective route for the Waasigan transmission line.

Interrogatory:

a) It has been my understanding that considerations for using the Steep Rock Mine Corridor were abandoned earlier in the process because one of the affected traditional territories people demanded a 100-year ban on pesticide use. Please provide the documentation and emails to support this claim. Please provide the minutes of meetings, criteria comparison charts, or score sheets used to evaluate why the Steep Rock Mine brownfield corridor was not considered the most cost-effective route for the Waasigan Transmission Line project.

b) Please provide the IESO constraints with respect to crossovers.

c) Please provide the associated additional costs per crossover.

d) Please specify the width of the required corridor when not adjacent to the existing corridor.

e) Please provide the length that the Steep Rock corridor travels adjacent to the existing corridor and the length of the Steep Rock corridor that is not adjacent to any existing corridors.

f) Please list the constraints associated with using the Steep Rock corridor as well as mitigating actions that would be required to overcome these constraints, including, crossovers, detours, and potential dispositions to allow the Steep Rock corridor to exist along roadsides and adjacent to the existing corridor with less than the required 46 m corridor width.

g) Please provide the cost of additional crossovers or detours to overcome the constraints identified in answering question f) above.

h) Please provide the area of deforestation required for the construction of the transmission line alignment in the Steep Rock Mine corridor (excluding the Steep Rock Mine corridor brown field)

i) Please provide the area of deforestation required for the construction of the proposed Waasigan transmission line corridor including the land required for the proposed helicopter corridor

j) Please provide the cost per square kilometre of deforestation

k) Please provide the cost to deforest the Steep Rock Mine brown field corridor

l) The proposed Waasigan route at Three Mile Bay is to be constructed on along the side of a hill slope, were the additional costs of building on a slope included in the cost estimate. Are there other slope side areas along the proposed corridor and were these costs included in your proposal.

Response:

a) The process completed to identify alternative routes to be evaluated, as contained within the Environmental Assessment ("EA")[1], is detailed in the Amended Terms of Reference[2] approved by the Ministry of the Environment, Conservation and Parks.

   i. Hydro One declines to respond to questions related to pesticide effects as these matters relate to the EA and are not relevant to issues in this proceeding, namely price, quality and reliability.

   ii. As the question refers to route evaluation and selection, these matters are addressed in Hydro One's EA. Please refer to Section 2.0 of the EA which presents

[1] www.hydroone.com/about/corporate-information/major-projects/waasigan/project-approvals
[2] https://www.hydroone.com/abouthydroone/CorporateInformation/majorprojects/Waasigan/Documents/final-ea-report/appendices/Appendix_1.0-A%20Terms%20of%20Reference.pdf

detailed results of the route evaluation. While route evaluation and selection matters fall outside the scope of this proceeding, to be helpful, Hydro One provides the following additional comments addressing its consideration of what it understands to be the referenced "Steep Rock Mine brownfield corridor".

This corridor refers to a decommissioned 115 kV right-of-way located in the Atikokan to Shebandowan Lake area. While parts of this corridor were considered during the EA process, these limited sections were not assessed to be as optimal as compared to the preferred route. In the Shebandowan Lake area, the use of the decommissioned corridor was deemed less optimal given the need for crossovers that would be required for the line to be operated and maintained amongst existing facilities. Crossovers are not preferred approaches for transmission facility operations as they impose additional reliability risks upon both the new and existing facilities. Where practicable, crossover construction and operation approaches are avoided. Other reasons for rejecting the Steep Rock Mine corridor in this area included limited space available to construct a 230 kV line and physical constraints on the north side of the existing transmission line. The remaining portions of the Steep Rock Mine corridor between Atikokan to Shebandowan Lake area were also ruled out as being the preferred alternative given that this route would not follow existing linear infrastructure, thereby introducing natural environment disadvantages, such as habitat fragmentation for wildlife, and would encounter physical constraints (i.e., an active aggregate operation). The "brownfield" nature of this corridor was not considered to be an advantage over the preferred route given the extent of re-vegetation along this decommissioned corridor. In light of these circumstances, the preferred route identified by Hydro One was still considered preferred and detailed design and costing, of the Steep Rock Mine corridor was not carried out.

b) Hydro One is interpreting what the intervenor calls as 'crossovers' to refer to the aerial crossing of one high voltage transmission line by another high voltage transmission line. The IESO enforces North American Electric Reliability Corporation ("NERC") reliability standards and Northeast Power Coordinating Council ("NPCC") criteria through Market Rules in Ontario subject to Ontario Energy Board oversight, through its Market Rules, operating policies, and planning criteria, none of which specify requirements or constraints with respect to crossovers. Hydro One considers the use of crossovers following industry best practice, cost prudency, risk mitigation, power supply reliability requirements, engineering and design constraints which represent appropriate system stewardship. Crossovers impose a reliability and safety risk and their use is minimized to the best extent possible. The reliability risk that arises with crossovers concerns the fact that line equipment of the upper line may interfere with the operation of a lower line and thus increasing the probability of both lines being lost

and thus impacting system reliability. Also, to avoid a safety risk there is often the need to de-energize one line while the other line is being constructed or maintained. Addressing this safety risk also impacts overall system operations and system reliability.

c) Construction costs associated with crossovers, as described in in part b) above, are bespoke to the specific physical location of each crossover. These construction costs are affected by terrain, height of crossing, voltages, span lengths, material quantities, foundation requirements etc., which makes each crossing different. What also must be considered is the reliability cost associated with any future outages on both transmission lines involved in the crossing. Outages may be needed during the construction of the crossover and may be a consequence of storms, each of which carry a significant cost. When considered fully, the cost of crossovers can be multiples of the cost to build a typical transmission line span.

d) 46 m.

e) Please refer to part a) ii, above.

f) Please refer to part a) ii, above.

g) Please refer to part a) ii, above.

h) Please refer to part a) ii, above.

i) An assessment of the effects of the Project on vegetation and wetlands, including a description of the vegetation removal required, is addressed in Hydro One's EA[3] Section 6.4. Hydro One declines to respond further to this Interrogatory as the information requested is not relevant to the issues set out in the OEB's Procedural Order No. 1.

j) Costs associated with vegetation removal are included within the fixed price cost of the Engineering, Procurement, and Construction contractor. As a result, a cost per kilometre for vegetation removal is not available.

k) Please refer to interrogatory response a) ii, above.

l) All costs associated with building along slopes are included in the cost estimate.

[3] www.hydroone.com/about/corporate-information/major-projects/waasigan/project-approvals

LARRY RICHARD INTERROGATORY - 02

Preamble:

Issue 1.2 & 3.2

The Ecosystem Services Toolkit was developed to valuate the costs and impacts of projects that impact ecosystems. Hydro One used this process when developing the alignment from the Bruce Nuclear Generating system to the Milton Switching Station (p. 79 of the Ecosystem Services Toolkit).

Interrogatory:

a) Did Hydro One use the Ecosystem Services Tool Kit when assessing the costs of the Waasigan Transmission Line, and if not, why not?

b) If yes to a) what is the valuation of the ecosystems lost and the costs associated with the mitigating actions required to create equivalent habitats to those lost?

c) Were these costs included in the cost to construct the Waasigan Transmission line?

d) After considering the lost value of ecosystem services as evaluated in b), is the cost associated with using the Steep Rock Corridor expected to be approximately one third the cost associated with Hydro One's preferred route?

Response:

a) No, the Ecosystem Services Toolkit (the 'Toolkit') was not used to assess the financial costs of the Waasigan Transmission Project.

The referenced Toolkit is typically used to inform public policy development through systematic approaches that consider human impacts to ecological systems. Ecosystem assessments derived from the Toolkit are intended to inform environmental management and environmental policy and decision-making.[1] Hydro One also notes that the Toolkit was not used to establish route alignment for the Bruce to Milton Transmission Reinforcement Project as suggested in the Preamble to this Interrogatory.

[1] See: "Completing and Using Ecosystem Service Assessment for Decision-Making: An Interdisciplinary Toolkit for Managers and Analysts Value of Nature to Canadians Study Taskforce Federal, Provincial, and Territorial Governments of Canada"
https://publications.gc.ca/collections/collection_2017/eccc/En4-295-2016-eng.pdf

b) Not applicable.

c) Costs associated with measures to mitigate and offset habitat loss or transition (long-term change) that may occur as a result of the project (e.g., biodiversity initiative) have been accounted for in the total cost of the Project.

d) Not applicable. Refer to part b), above.

LARRY RICHARD INTERROGATORY - 03

Preamble:

Issue 1.2 & 3.2

The proposed Waasigan Transmission line travels through the Great Lakes Basin Ecosystem. The Ministry of Environment developed the document Assessing the Economic Value of Protecting the Great Lakes Ecosystems | ontario.ca as a guiding document for assessing the value of ecosystem services and the additional ancillary benefits and costs beyond the preliminary costs of establishing the site. The wetland at the end of Three Mile Bay on Lake Shebandowan is listed as unevaluated, however, given the size of this wetland (approximately 5 hectares), this wetland should be considered provincially significant. Further, the Ontario Natural Heritage Manual presents the province's recommended technical criteria and approaches in protecting natural heritage features and areas and natural heritage systems in Ontario.

Interrogatory:

a) Did Hydro One follow the governing document above and provide a value of the ecosystem services provided in the Great Lakes Basin and identify how these values are affected by the proposed Waasigan Transmission line project. If not, why not? If yes, what was the value of ecosystem services given to this project?

b) Did Hydro One evaluate the wetland at the end of Three Mile Bay or any of the other wetlands or waterways affected by the Waasigan project, and if not, why not?

c) Did Hydro One use the Natural Heritage Manual when developing the Waasigan Project? If not, why not?

d) Has Hydro One included the costs to rehabilitate/restore the wetland area should they cause damage by constructing the hydro corridor? If so, what are the estimated rehabilitation costs?

   If not, why were these costs not considered?

e) Has Hydro One included the costs of decreased property value based on shoreline aesthetics to the property owners affected by the Waasigan project in their valuations of alternative routes? If so, what is the estimated cost to property owners? If not, why was the loss of value for property owners not considered?

f) Has Hydro One included the costs of decreased property value based on the potential to reduce property value due to loss of recreation from cyanobacteria blooms caused by deforestation near the lake and shoreline wetlands? If so, what are the estimated costs? If not, why were these costs not considered?

g) Has Hydro One included the costs required to respond to and address an increased prevalence of cyanobacteria blooms due to deforestation of the riparian area, particularly along the slope of Three Mile Bay on Lake Shebandowan? If so, what are the estimated costs? If not, why were these costs not considered?

h) Please provide the number of properties affected if the Steep Rock Corridor was implemented and the number of properties affected by the proposed Waasigan Corridor.

i) Why weren't the camp owners of Three Mile Bay on Lake Shebandowan notified or consulted in the selection of the proposed Waasigan corridor and why haven't the property owners been offered a settlement agreement for the decreased property values from the transmission lines adjacent to their properties?

Response:

a) Natural heritage values are addressed in Section 6.0 of Hydro One's Environmental Assessment ("EA")[1]. Hydro One declines to respond to this Interrogatory request as the requested information is not relevant to the issues in this proceeding. The OEB's Procedural Order No. 1 issued to all parties participating in this proceeding expressly states issues concerning environmental matters and Indigenous consultation are not relevant to this proceeding unless demonstrated to relate to price, reliability and quality of electricity service.

b) Please refer to part a), above.

c) Please refer to part a), above.

d) The total Project cost forecast includes amounts associated with rehabilitation and restoration works for the Project. Rehabilitation costs are included as part of the Engineering, Procurement and Construction fixed price contract, as a result explicit rehabilitation costs are not available.

e) Effects to visual aesthetics are addressed in Section 7.4 of Hydro One's EA. Landowners from whom Hydro One requires permanent property rights for the project

[1] www.hydroone.com/about/corporate-information/major-projects/waasigan/project-approvals

are compensated for any impacts to the remaining property value as a result of the Project, as determined by an independent third-party appraiser.

f) Please refer to part a), above. Costs associated with implementation of mitigation measures to address potential effects to the natural environment have been accounted for in the total Project cost.

g) Please refer to part a), above. Costs associated with implementation of mitigation measures to address potential effects to the natural environment have been accounted for in the total Project cost.

h) Please refer to Exhibit I, Tab 5, Schedule 1, part a) ii regarding information on Steep Rock Corridor. For the Waasigan Project , there are 246 impacted properties.

i) Compensation for valuation declines to properties on which the Project is located, is negotiated directly with each affected landowner. Hydro One's Land Acquisition Compensation Principals[2] ("LACP") does not provide compensation in circumstances where there is no real property interest acquisition requirement, such as properties located away from or adjacent to the proposed corridor. Acquisition of these types of property interests are not required for the construction and ongoing operation of the Project. Engagement is addressed in Section 4.0 of Hydro One's Environmental Assessment ("EA")[3]. Hydro One declines to respond further to this Interrogatory as the requested information is not relevant to the issues in this proceeding The OEB's Procedural Order No. 1 issued to all parties participating in this proceeding expressly states issues concerning environmental matters and Indigenous consultation are not relevant to this proceeding unless they pertain to price, reliability and quality of electricity service.

[2] The Project's LACP's are found at Exhibit I, Tab 1, Schedule 15, Attachment 1.
[3] www.hydroone.com/about/corporate-information/major-projects/waasigan/project-approvals

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