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Pasquale Catalano
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BY EMAIL AND RESS

May 15, 2026

Mr. Ritchie Murray
Acting Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Mr. Murray,

EB-2026-0112 – Hydro One Networks Inc. Leave to Construct Application – D6 Relocation Project Updated Application and Evidence

Further to the leave to construct application filed on May 13, 2026, Hydro One Networks Inc. (Hydro One) is providing a minor update to remove a disclaimer that was inadvertently included in all pages of Attachment 2 of Exhibit E, Tab 1, Schedule 1.

An electronic copy of this correspondence and the associated Updates has been filed using the OEB's Regulatory Electronic Submission System ("RESS"). Similarly, Hydro One has also provided a complete Application and Evidence that includes the Updates ("the Updated Application") for ease of reference using the OEB's RESS. The Updated Application remains consistent with the OEB Rules of Practice and Procedure and the OEB's Practice Direction on Confidential Filings. Hydro One confirms that all redacted versions of documents filed in support of the Updated Application do not disclose any personal information under the Freedom of Information and Protection of Privacy Act.

Sincerely,



Pasquale Catalano

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Mr. Ritchie Murray
Acting Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Mr. Murray,

EB-2026-0112 – Hydro One Networks Inc. Leave to Construct Application – D6 Relocation Project – Application and Evidence

Pursuant to Section 92 of the Ontario Energy Board Act, 1998, (the "Act"), Hydro One Networks Inc. ("Hydro One") seeks the Ontario Energy Board's ("OEB") approval for an Order or Orders granting leave to construct transmission facilities ("**D6 Relocation Project**" or "**Project**") in the county of Renfrew and passing through three municipalities, specifically the towns of Petawawa, Laurentian Hills and Deep River.

Additionally, pursuant to Section 97 of the Act, Hydro One seeks OEB approval for an Order granting approval of the forms of land use agreements offered or to be offered to affected landowners.

Hydro One is confirming that the documents filed in support of the referenced application do not include any personal information under the Freedom of Information and Protection of Privacy Act (Ontario) ("FIPPA") with respect to this Application. Any FIPPA related information in the Application has been redacted. Consistent with Section 10 of the OEB's Practice Direction, the personal information contained at Attachment 3 of Exhibit E, Tab 1, Schedule 1 is also redacted as the information about an identifiable individual that may be of a personal nature.

Furthermore, Hydro One is confirming that the System Impact Assessment report appendices, which contain confidential information and if disclosed could reasonably be expected to pose a potential security threat to the integrated power system, have been omitted from this Application. This information is contained at Attachment 1 of Exhibit F, Tab 1, Schedule 1. This approach is consistent with the OEB's Chapter 4 Filing Requirements.[1]

Likewise, Appendix 1 of the Customer Impact Assessment filed as Attachment 1 of Exhibit G, Tab 1, Schedule 1, has been redacted. This information has been considered to be presumptively confidential, consistent with Appendix B of the OEB's Practice Direction on Confidential Filings[2] on the basis that it is

[1] OEB Chapter 4 Filing Requirements – Issued December 16, 2025 – Section 4.3.6.
[2] Last Revised on December 17, 2021.

information that would disclose load profiles, energy usage and billing information of a specific customer that is not personal information.

An electronic copy of this Application and Evidence has been filed using the OEB's Regulatory Electronic Submission System.

Sincerely,



Pasquale Catalano

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EXHIBIT LIST

Exhibit	Tab	Schedule	Attachment	Contents
A				
	1	1		Exhibit List
	1	2		Application Table of Concordance
	1	3		List of Acronyms and Abbreviations
B				
	1	1		Application
	2	1		Project Overview Documents
	2	1	1	General Area Map
	2	1	2	Schematic Diagram of Proposed Line Facilities
	3	1		Evidence In Support of Need
	3	1	1	IESO Supplemental Evidence to Support the Need for the Project
	3	1	2	Letter from Department of Defence - Garrison Petawawa
	4	1		Project Categorization and Classification
	5	1		Cost Benefit Analysis and Options
	6	1		Quantitative and Qualitative Benefits of the Project
	7	1		Apportioning Project Costs and Risks
	8	1		Connection Projects Requiring Network Reinforcement
	9	1		Transmission Rate Impact Assessment
	10	1		Revenue Requirement Information and Deferral Account Requests
	10	1	1	Investment Summary Document: EB-2019-0082 T-SR-19
	11	1		Project Schedule

Exhibit	Tab	Schedule	Attachment	Contents
C				
	1	1		Descriptions of the Physical Design
D				
	1	1		Operational Details
E				
	1	1		Land Matters
	1	1	1	Hydro One's D6 Land Acquisition Compensation Principles
	1	1	2	Detailed Routing Maps
	1	1	3	List of Impacted Properties and Permits Associated with the Project Route
	1	1	4	Early Access Agreement
	1	1	5	Option to Purchase a Limited Interest – Easement
	1	1	6	Compensation and Incentive Agreement – Easement
	1	1	7	Agreement for Temporary Rights
	1	1	8	Damage Claim Agreement/Waiver
F				
	1	1		System Impact Assessment
	1	1	1	Final IESO System Impact Assessment
G				
	1	1		Customer Impact Assessment
	1	1	1	Final Customer Impact Assessment
H				
	1	1		Regional and Bulk Planning
	1	1	1	Renfrew Region Integrated Regional Resource Plan - 2022
	1	1	2	Renfrew Regional Infrastructure Plan - 2023

APPLICATION TABLE OF CONCORDANCE

Exhibit	Content	FR Section	Hydro One S.92 Application Section
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			A-01-02 – Application Table of Concordance
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	Administrative Matters	4.3.2.1	B-01-01 – Application
	Project Overview	4.3.2.2	B-02-01 – Project Overview Documents C-01-01 – Descriptions of the Physical Design
	Evidence in Support of Need for the Project	4.3.2.3	B-03-01 – Evidence in Support of Need
	Project Categorization	4.3.2.4	B-04-01 – Project Categorization and Classification
	Analysis of Alternatives	4.3.2.5	B-05-01 – Cost Benefit Analysis and Options B-06-01 – Quantitative and Qualitative Benefits of the Project H-01-01 – Regional and Bulk Planning
	Project Costs	4.3.2.6	B-07-01 – Apportioning Project Costs and Risks B-09-01 – Transmission Rate Impact Assessment
	Risks	4.3.2.7	B-07-01 – Apportioning Project Costs and Risks
	Comparable Projects	4.3.2.8	B-07-01 – Apportioning Project Costs and Risks
	Connection Projects that Also Address a Network Need	4.3.2.9	B-08-01 – Connection Projects Requiring Network Reinforcement
	Connection Projects Requiring Network Reinforcement	4.3.2.10	B-08-01 – Connection Projects Requiring Network Reinforcement
	Transmission Rate Impact Assessment	4.3.2.11	B-09-01 – Transmission Rate Impact Assessment
	Establishment of Deferral Accounts	4.3.2.12	B-10-01 – Revenue Requirement Information and Deferral Account Requests

Exhibit	Content	FR Section	Hydro One S.92 Application Section
	Capital Contribution Period	4.3.2.13	B-09-01 – Transmission Rate Impact Assessment
	Project Schedule	4.3.2.14	B-11-01 – Project Schedule
C	**Project Details**	**4.3.3**	
	The Route	4.3.3.1	B-02-01 – Project Overview Documents
	Description of the Physical Design	4.3.3.2	C-01-01 – Descriptions of the Physical Design
	Maps	4.3.3.3	E-01-01 – Land Matters
D	**Design Specification and Operational Data**	**4.3.4**	
	Operational Details	4.3.4.1	D-01-01 – Operational Details
E	**Land Matters**	**4.3.5**	
	Description of Land Rights Required	4.3.5.1	E-01-01 – Land Matters
	Land Acquisition Process	4.3.5.2	E-01-01 – Land Matters
	Land-related Forms	4.3.5.3	E-01-01 – Land Matters
	Early Access to Land	4.3.5.4	E-01-01 – Land Matters
F	**System Impact Assessment**	**4.3.6**	F-01-01 – System Impact Assessment
G	**Customer Impact Assessment**	**4.3.7**	G-01-01 – Customer Impact Assessment
H	**Regional and Bulk Planning**	**4.3.8**	
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	Regional Infrastructure Plan	4.3.8.2	H-01-01 – Regional and Bulk Planning
	Bulk System Plan	4.3.8.3	H-01-01 – Regional and Bulk Planning

LIST OF ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Acronym or Abbreviation Expansion
A	Amperes
AACE	Association for the Advancement of Cost Engineering *(estimate classification system)*
AC/DC	Alternating Current / Direct Current
ACSR	Aluminium-Conductor Steel-Reinforced cable
ACSR/TW	Aluminium-Conductor Steel-Reinforced, trapezoidal shaped cable
AFUDC	Allowance for Funds Used During Construction
C	Celsius
CIA	Customer Impact Assessment
Class EA	Class Environmental Assessment
CSA	Canadian Standards Association
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DND	Department of Defence
DS	Distribution Station
EA	Environmental Assessment
ESR	Environmental Study Report
Hydro One *(HONI)*	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IPB	Inter Provincial Boundary
IRRP	Integrated Regional Resource Plan
ISD	Investment Summary Document
ISOC	Integrated System Operating Center
JCT	Junction
kcmil	Kilo-circular mils *(unit of measure of the area of a wire with a circular cross section)*
km	Kilometer
kV	Kilovolt
kW	Kilowatt
LACP	Land Acquisition Compensation Principles

Acronym or Abbreviation	Acronym or Abbreviation Expansion
LTE	Long Term Emergency rating
m	Meter
MECP	Ministry of the Environment, Conservation and Parks
MTO	Ministry of Transportation
MTS	Municipal Transformer Station
MVA	Megavolt-ampere
MW	Megawatt
MWHR *(or MWH)*	Megawatt-hour
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
OEB	Ontario Energy Board (the Board)
OMA	Operations, Maintenance and Administrative costs
OPGW	Optical Ground Wire
PV	Present Value
RIP	Regional Infrastructure Plan
ROE	Return on Equity
ROW	Right-of-Way
RPP	Regulated Price Plan
SCADA	Supervisory Control and Data Acquisition system
SIA	System Impact Assessment
SS	Switching Station
TAC	Technical Advisory Committee
TS	Transformer Station
TSC	Transmission System Code
TSP	Transmission System Plan
UTR	Uniform Transmission Rates

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B (the "**Act**").*

AND IN THE MATTER OF an Application by Hydro One Networks Inc. ("**Hydro One**") pursuant to s. 92 of Act for an Order or Orders granting leave to construct transmission line facilities in the county of Renfrew and passing through three municipalities, specifically the towns of Petawawa, Laurentian Hills and Deep River.

AND IN THE MATTER OF an Application by Hydro One pursuant to s. 97 of the Act for an Order granting approval of the forms of land use agreements offered or to be offered to affected landowners.

APPLICATION FOR LEAVE TO CONSTRUCT

May 13, 2026

A. INTRODUCTION

1. The Applicant is Hydro One, a subsidiary of Hydro One Inc. The Applicant is an Ontario corporation with its head office in the City of Toronto. Hydro One carries on the business, among other things, of owning and operating transmission facilities within Ontario.

2. Hydro One hereby applies to the OEB (or "Board") pursuant to s. 92 of the Act for an Order or Orders granting leave to construct a 115 kV single-circuit transmission line between Chalk River CTS and Petawawa Junction ("JCT") in the Renfrew area referred to herein as the "Project" of "D6 Relocation Project".

3. The total length of the Project is approximately 21 kilometers, including 18 kilometers on federally owned lands and the remainder on privately owned lands. The Project is sited within a corridor approximately 30 meters in width.

4. Hydro One currently holds 100% of the privately held land rights required along the route and has achieved voluntary early access agreements and voluntary settlement agreements with 100% of the affected private landowners. Hydro One is seeking approval from the OEB of the form of the voluntary property rights agreements offered or to be offered to affected landowners, pursuant to s. 97 of the Act.

5. The proposed in-service date for the Project is April 28, 2028, which is predicated on an assumed construction commencement date of October 2026. To support this construction commencement date, Hydro One respectfully requests the Board grant the relief sought in this Application by September 2026.

B. NATURE OF THE PROJECT

6. Circuit D6 is a 98.2 km, 115 kV, single circuit transmission line that connects Des Joachims Transformer Station ("TS") with Pembroke TS. It is the only 115 kV transmission supply line to the Des Joachims TS and, along its connection with Pembroke TS, solely services Craig Distribution Station ("DS"), Deep River DS, Forest Lea DS and Petawawa DS, making continued service along this corridor essential for maintaining supply to existing loads. The existing line was built in the 1940s, and this segment of line has not undergone any major refurbishment since.

7. The segment of circuit D6 addressed by this Project, spanning between the CTS and JCT facilities, has been confirmed through condition assessment verification to have reached end of life. The Project is designed to support the regional planning objectives for the Renfrew Region and is required to maintain reliable supply.

8. The Project is consistent with the recommendations made by the IESO in the Renfrew Regional IRRP. A copy of the IRRP can be found at **Exhibit H, Tab 1, Schedule 1, Attachment 1.** The IESO has also provided a report supporting the need for the Project, a copy of which is included at **Exhibit B, Tab 3, Schedule 1, Attachment 1**. The Project has been identified as a discretionary sustainment project, as further described in **Exhibit B, Tab 4, Schedule 1**.

9. Additionally, circuit D6's existing routing traverses an active military base, including a live firing range, operated by the DND. The DND has confirmed that the proposed refurbishment activities conflict with active military training operations and pose multiple safety risks, including the hazard of live unexploded ordnances, should the in-situ refurbishment occur. The DND has also confirmed that these risks cannot be adequately mitigated while the transmission line remains in its current location and, pursuant to the Defence Controlled Access Area Regulations, SOR/86-957, that the DND could not accommodate Hydro One's requests for access to the transmission

corridor in the manner required to adequately undertake construction of an in-situ refurbishment.

10. Accordingly, the DND has requested that a section of circuit D6 be relocated away from the military base, which would reduce the overall length of the currently existing section from approximately 29 kilometers to approximately 21 kilometers ("Proposed Relocation"). Hydro One proposes to relocate circuit D6 to comply with the DND's requirements and to increase ongoing safety, access and operations of the line in a manner that protects the public. A copy of the correspondence received from the DND is provided at **Exhibit B, Tab 3, Schedule 1, Attachment 2**.

11. The 115 kV 411 kcmil ACSR/TW conductor selected by Hydro One to construct the new transmission line is predicated on Hydro One's commitment to minimize transmission line losses where feasible. Further information regarding the transmission line loss analysis for this Project is provided in **Exhibit B, Tab 5, Schedule 1**.

12. A copy of an overview map of the Project area is provided in **Exhibit B, Tab 2, Schedule 1, Attachment 1,** and a copy of a schematic diagram of the Project can be found at **Exhibit B, Tab 2, Schedule 1, Attachment 1.**

13. The Project is subject to the Class Environmental Assessment for Transmission Facilities (2024) process in accordance with the *Ontario Environmental Assessment Act.* The *Draft Environmental Study Report ("ESR")* was released for a 30-day public review period in February, 2026. Hydro One expects to file the Final ESR and Statement of Completion with the MECP in Q2 2026.

14. The proposed in-service date for the Project is April 28, 2028. This forecast in-service date is predicated on an assumed construction commencement date of October 2026. To support this construction commencement date, Hydro One requests OEB

approval of the Project by September 2026. A copy of the Project schedule is provided at **Exhibit B, Tab 11, Schedule 1**.

15. The IESO has completed a Final SIA for the Project. The Final SIA concludes that the Project is expected to have no material adverse impact on the reliability of the integrated power system and recommends that a *Notification of Conditional Approval for Connection* be issued. A copy of the IESO's Final SIA is provided at **Exhibit F, Tab 1, Schedule 1, Attachment 1**.

16. Hydro One has completed a Final CIA in accordance with Hydro One's connection procedures. A copy of the Final CIA is provided at **Exhibit G, Tab 1, Schedule 1, Attachment 1**. Hydro One will fulfill all requirements of the SIA and the CIA, and will obtain all necessary approvals, permits, licences, certificates, agreements, and rights required to construct the Project.

17. The forecast total capital cost of the Project is $37.1 million[1]. Details pertaining to these costs are provided at **Exhibit B, Tab 7, Schedule 1**.

18. The Project will relocate and rebuild existing transmission line facilities that have reached their end of life and have been identified for refurbishment to return the existing circuit to like-new condition. Subsequently, the expected rate impact associated with the Project (using 2026 OEB-approved uniform transmission rates as filed in **Exhibit B, Tab 9, Schedule 1)** is a $0.02/month (or 0.01%) increase on a typical residential customer's bill under RPP.

[1] An additional $3.1M of OM&A removal costs are associated with completing this Project.

C. PROJECT LAND REQUIREMENTS

19. Five new privately held permanent land rights on the proposed route are required to accommodate the Project. No temporary rights for construction purposes are anticipated along the corridor. Those five new privately held property rights were acquired voluntarily by Hydro One. Hydro One met with affected property owners as early as March 2025 regarding Hydro One's voluntary land acquisition process. As of December 2025, five voluntary property settlement offers pertaining to privately held lands had been made by Hydro One and accepted by affected landowners. Further information regarding the real estate needs to complete this Project are provided in **Exhibit E, Tab 1, Schedule 1**.

20. Hydro One seeks approval of the form of the voluntary property rights agreements offered or to be offered to affected landowners, pursuant to s. 97 of the Act. The agreements are in the same form as previously approved in prior Hydro One's leave to construct proceedings. During property acquisition discussions, affected landowners were advised by Hydro One that they have the option to receive independent legal advice and that Hydro One is committed to reimbursing affected landowners for reasonably incurred legal fees associated with the review and execution of the necessary land rights agreements. The form of the agreements for which approval is sought is found at attachments to **Exhibit E, Tab 1, Schedule 1**.

21. Hydro One consents to the conditions outlined in the OEB's standard conditions of approval for electricity transmission leave to construct applications[2] for this Project.

[2] https://www.oeb.ca/sites/default/files/issues-list-LTC-electricity.pdf

D. PUBLIC INTEREST

22. The Project is being undertaken to address the reliability needs of the transmission system due to aging facilities that have reached their end of life. The Project meets the needs of the transmission system and connected customers in the local area as the renewed assets can be expected to improve the quality of service and reliability of the circuit.

23. There are no practical alternatives to the Project scope of work. Further information regarding the cost benefit analysis of the Project is provided in **Exhibit B, Tab 5, Schedule 1**.

24. The Proposed Relocation is prudent, efficient and necessary to address the challenges posed by the DND military base. The Proposed Relocation is expected to enhance operational safety compared to the in-situ operation of the line, including the ongoing access need for maintenance along the proposed route in a manner that protects the public.

25. As documented in the CIA[3], no directly connected customers are adversely affected by the Project. The Project concords with the commitments undertaken through the Class EA process. The IESO's SIA[4] confirms that the Project will have no material adverse impact on the reliability of the integrated power system.

26. The Project has considered transmission line losses in a cost-effective manner and the five additional privately held property rights required to complete the Project have already been acquired through voluntary agreement.

27. Overall, the Project is not expected to have a material impact on Uniform Transmission Rates or the overall average Ontario consumer's electricity bill.

[3] Exhibit G, Tab 1, Schedule 1, Attachment 1.
[4] Exhibit F, Tab 1, Schedule 1, Attachment 1.

E. REQUESTED RELIEF

28. Hydro One requests:
    a) An Order or Orders made pursuant to section 92 of the Act granting leave to construct the Project;
    b) An approval of the form of the voluntary property rights agreements offered or to be offered to affected landowners, pursuant to s. 97 of the Act, and
    c) Such other relief as Hydro One may request or as the Board may direct.

29. The Application is supported by written evidence which includes details of the Applicant's proposal for the transmission line. The written evidence is prefiled and may be amended from time to time prior to the Board's final decision on this Application.

30. Acronyms are used throughout the evidence and those acronyms are defined at **Exhibit A, Tab 1, Schedule 3**.

31. Hydro One requests that a copy of all documents filed with the Board be served on the Applicant and the Applicant's counsel, as follows:

    a) The Applicant:

    Ms. Eryn Mackinnon
    Regulatory Advisor
    Hydro One Networks Inc.

Mailing Address:	7th Floor, South Tower 483 Bay Street Toronto, Ontario M5G 2P5
Telephone:	(437) 318-3700
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b) The Applicant's Counsel:

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PROJECT OVERVIEW DOCUMENTS

Hydro One is seeking approval from the OEB to relocate a transmission line facility by constructing a portion of the D6 115 kV transmission line facility in an alternate location between the Chalk River Customer Transformer Station ("CTS") and Petawawa Junction ("JCT") facilities. The proposed relocation would reduce the overall length of the currently existing (or "in-situ") section from approximately 29 km to approximately 21 km.

The D6 Relocation Project addresses the necessary sustainment of a section of the existing D6 115 kV transmission line, which has reached end of life and requires replacement. The relocation of the section of D6 line is necessitated by the DND. This existing D6 line section identified for refurbishment currently traverses through an active live military firing range area of the DND Garrison Petawawa military base. The existing line was built in the 1940s, and since that time, the DND's military operations, training, live firing range exercises, and overall level of activities conducted on their lands has significantly increased.

The planned sustainment of this section of the D6 transmission line was originally expected to occur in-situ. However, during engagement with stakeholders, DND advised Hydro One that the existing transmission corridor located within the military base, and the proposed refurbishment activities planned for it, conflict with active military training operations and pose multiple safety risks should the in-situ refurbishment occur. Furthermore, DND confirmed that these risks cannot be adequately mitigated while the transmission line remains in its current location and that DND could not accommodate Hydro One's requests for access (both duration and frequency) to the transmission corridor in the manner required to adequately undertake construction of an in-situ refurbishment[1]. Although Hydro One holds an easement within the affected corridor and has held the easement since 1946. DND confirmed that the National Defence Act, R.S.C.,

[1] A copy of the correspondence received from the DND is provided as Exhibit B, Tab 3, Schedule 1, Attachment 2.

1985, c. N-5 supersedes Hydro One's easement rights, thereby limiting Hydro One's ability to safely access, operate, and maintain the line. As a result, continued operation in the existing alignment is not feasible.

Notably, the level of unexploded ordinances (i.e. military explosives) is expected to be plentiful and situated in and around the existing siting of the D6 transmission line. Furthermore, in concert with these electrical facility risks, as described in **Exhibit B, Tab 3, Schedule 1, Attachment 2**, continued use on the existing corridor imposes access restrictions to the transmission assets as it will require Hydro One to follow the Defence Controlled Access Area Regulations Defence Controlled Access Area Regulations, SOR/86-957. These challenges, combined with the anticipated daily live firing range used by the DND military staff adjacent to the transmission line in this area, necessitates the relocation of the section of the D6 circuit away from the military base.

The D6 Relocation Project will replace the end-of-life transmission line facilities with new infrastructure that will bring this section of the circuit back to 'as-new' condition. This will involve building a new 115 kV transmission line, that will utilize a 411.4 kcmil ACSR/TW conductor. on a new right-of-way, geographically located along Highway 17. 411.4 kcmil ACSR/TW is Hydro One's minimum standard transmission conductor.

The D6 Relocation Project route passes through the county of Renfrew and three municipalities consisting of the Town of Petawawa, the Town of Laurentian Hills and the Town of Deep River. At the south end of the Project, the route of the Project traverses over approximately 3 km of privately and publicly owned lands until reaching the Petawawa River. On the north side of the river, the Project traverses 18 km of mainly federally owned lands while abutting Highway 17.

A copy of a map showing the geographic location of the existing facilities and the proposed relocation route is provided at **Exhibit B, Tab 2, Schedule 1, Attachment 1.** A copy of the schematic diagram of the transmission line facilities is provided at **Exhibit B, Tab 2, Schedule 1, Attachment 2.**

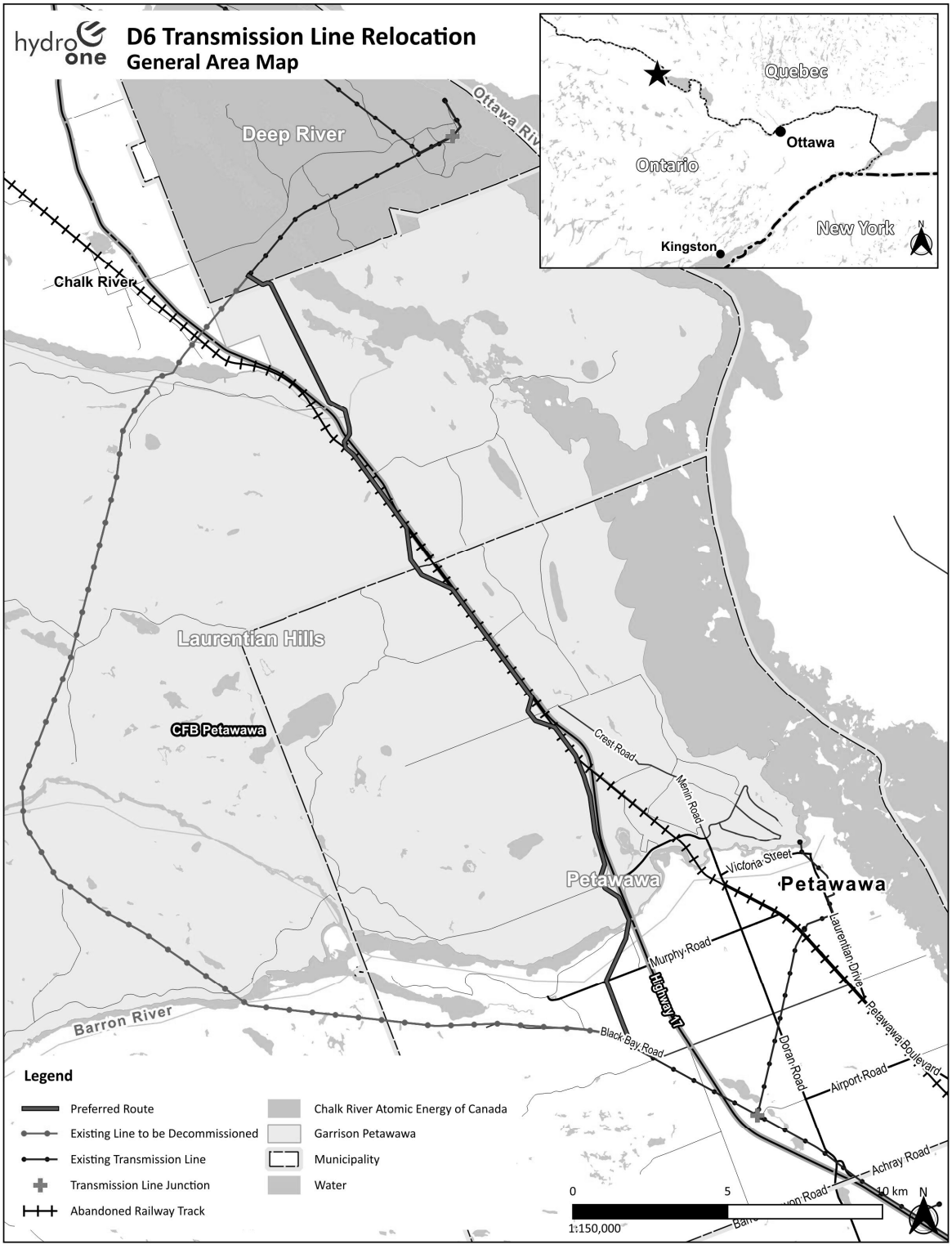
The proposed facilities subject to s. 92 approval consist of:

- Approximately 21 km of new 115 kV single-circuit transmission line between Chalk River Junction and Petawawa Junction on a new corridor, the majority of which will be located along Highway 17. The line will connect into exiting Hydro One corridors near Chalk River at the north end and along Black Bay Road at the south end.
- The route for the proposed circuits requires the acquisition of new land rights in the form of permanent easements across five private landowner properties, Hydro One has secured voluntary agreements from 100% of those private landowners. No further additional privately held land rights are required for this Project.

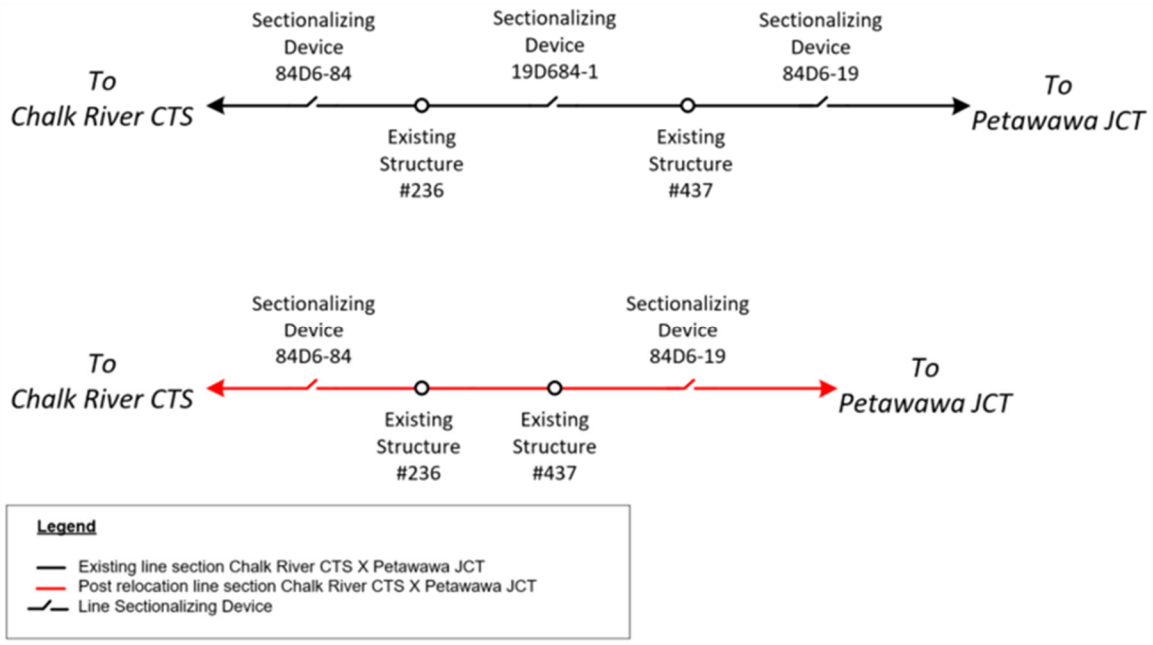
The Project is subject to the Class Environmental Assessment for Transmission Facilities (2024) under the provincial *Environmental Assessment Act*, R.S.O. 1990, c. E.18. A Draft Environmental Study Report ("ESR") was made available for public review in February 2026. The Class Environmental Assessment process is expected to be completed in Q2 2026.

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GENERAL AREA MAP



PROPOSED FACILITIES:
115 kV CIRCUIT D6, CHALK RIVER CTS X PETWAWA JCT
PRE AND POST RELOCATED LINE SECTION SCHEMATIC DIAGRAM



Note: The Project's scope identifies a section of the current Transmission circuit D6 to be relocated outside of CFB Petawawa training grounds. The relocation will take place between existing structure #236 and structure #437. Relocation will reduce the overall length of the line between the forementioned structures from approximately 29 km to 21 km. Through this relocation, sectionalizing device 19D684-1, which serves to isolate the segment of line within CFB Petawawa, will be removed from circuit D6.

EVIDENCE IN SUPPORT OF NEED

Circuit D6 is a 98.2 km, 115 kV, single circuit transmission line that connects Des Joachims TS with Pembroke TS. It is the only 115 kV transmission supply line to the Des Joachims TS and along its connection with Pembroke TS and solely services Craig DS, Deep River DS, Forest Lea DS and Petawawa DS, making continued service along this corridor essential for maintaining supply to existing loads. The segment of circuit D6 addressed by this Project, spanning between Chalk River CTS and Petawawa JCT, has been confirmed through condition assessment verification to have reached end of life.[1]

This segment of the D6 transmission line requiring renewal and relocation currently traverses an active military base, including a live firing range, namely the Canadian Forces Base Petawawa. Hydro One has been unsuccessful in securing adequate access (both frequency and duration) and approvals from the DND to address the asset need in-situ. A copy of the correspondence received by Hydro One from the DND is provided as **Attachment 2** to this Exhibit, outlining the restricted access to the current in-situ line location, and the DND's support for the proposed transmission line section's relocation.

Although Hydro One continues to hold land rights to the existing corridor to operate this transmission line facility, this corridor is enveloped within the DND's military training grounds. The *Defence Controlled Access Area Regulations*, SOR/86-957 supersedes those land rights and provides the DND with the ability to restrict Hydro One's access to the corridor. The DND has also confirmed to Hydro One that those grounds contain the hazard of live unexploded ordnances. These explosives present an unacceptable safety risk to the transmission facilities and Hydro One staff, both in terms of present and future access and for maintenance and inspection purposes.

[1] In-situ sustainment work for the majority of the circuit requiring renewal has already been completed under a separate project approved by the OEB. Please refer to EB-2019-0082 - Exhibit B-1-1, ISD SR-19, page 13 of 15.

As a result, Hydro One can no longer operate the impacted in-situ section of the D6 transmission line facility in a safe and reliable manner and has no option but to relocate this section of line away from the active DND military training grounds.

The new route for the relocated segment of D6 has been developed in concert with the DND and remains situated on DND lands. However, the new infrastructure siting is further removed from any area where dangerous activities are expected to occur, both currently and in the future. Relocating these assets will enable Hydro One to operate and maintain the identified section of the line in a more reliable and safe manner in the future. This relocation and reduction of the incongruent activities that exist in-situ will allow Hydro One to meet its obligations in respect of maintaining the reliability and integrity of its transmission system in the local area in accordance with its Transmission License and the OEB's TSC.

The proposed relocated line segment will be constructed between existing D6 line structures #236 and #437, and will reduce the overall line length between these structures from approximately 29 km to 21 km. To determine the appropriate scope of the relocated line facility and its preferred alternative, Hydro One followed its conductor analysis and selection process, which considers and evaluates the impact of line losses by proposing the most cost-effective conductor. This analysis is described in more detail in **Exhibit B, Tab 5, Schedule 1**.

The IESO has provided support to Hydro One for the proposed D6 Relocation Project via the *Supplemental Evidence to Support the Need for the 115 kV D6 Transmission Line Relocation Project* report (the "Report") which is included in **Attachment 1** to this Exhibit. The Report aligns with the findings of the IESO's regional planning for the Renfrew Region[2] issued in December 2022 that the Project is required to ensure continued safe and reliable supply for this region. The Report supports the proposed scope of work and confirms the IESO is also not aware of, and has not identified, any additional system needs

[2] https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Renfrew/renfrew-IRRP-Report.pdf

or additional load supply requirements in the area that might impact the D6 Relocation Project.

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Supplemental Evidence to Support the Need for the 115 kV D6 Transmission Line Relocation Project

Independent Electricity System Operator

ieso
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Powering Tomorrow.

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1. Executive Summary

The Independent Electricity System Operator (IESO) provides this evidence in accordance with Chapter 4, Section 4.3.2.3 of the Ontario Energy Board's (OEB) Filing Requirements for Electricity Transmission Applications to identify the linkages and interdependencies between Hydro One Network Inc.'s (Hydro One) proposed 115 kV D6 transmission line relocation project, its underlying end-of-life refurbishment need, and the regional planning process for the Renfrew Region[1].

The 115 kV D6 transmission line is the only transmission supply line to the Des Joachims subsystem of the Renfrew Region and serves several stations in the area making continued service on this corridor essential to maintaining supply to existing loads.

The IESO supports the proposed project as it aligns with the findings of the IESO's regional planning for the Renfrew Region and is required to ensure continued reliable supply on the only transmission circuit serving existing loads.

[1] For regional planning purposes, the IESO's Renfrew Region is made up of 18 municipalities including the towns of Armprior, Deep River, Laurentian Hills, Petawawa, and Renfrew. Also, the townships of Admaston/Bromley, Bonnechere Valley, Brudenell, Lyndoch and Raglan, Greater Madawaska, Head, Clara and Maria, Horton, Killaloe, Hagarty and Richards, Laurentian Valley, Madawaska Valley, McNab/Braeside, North Algona Wilberforce and Whitewater Region; as well as the City of Pembroke.

2. Background

2.1 Power System Planning in Ontario

The IESO is responsible for conducting independent planning for electricity generation, demand management, conservation and transmission in Ontario. In carrying out this mandate, the IESO undertakes planning activities to ensure that the province has, and will continue to have, an adequate and reliable supply of resources and transmission to meet Ontario's electricity needs.

The IESO's transmission planning generally consists of regional planning and bulk system planning. These are two separate but inter-related planning activities. Regional planning is carried out according to the requirements set out in the IESO's OEB issued licence. Regional planning produces plans that address system issues that are local in nature, within 21 planning regions covering the province.

Bulk system planning is carried out by the IESO to address system issues which are more provincial in nature, such as the province-wide need for generation capacity, and transmission system solutions to enable transporting power reliably and economically across the province. The IESO also undertakes planning activities to maintain compliance with regulatory and reporting requirements, such as those established by the North American Electric Reliability Corporation reliability standards and the Northeast Power Coordinating Council criteria.

2.2 Regional Planning for Renfrew Region: Background

The most recent regional planning cycle for the Renfrew Region began with Hydro One's 2021 Needs Assessment, which identified several issues in the area, including a need to undertake an end-of-life refurbishment of the 115 kV D6 transmission line, as well as emerging station capacity needs at Pembroke transformer station (TS), Forest Lea distribution station (DS), and Petawawa DS.

Following the Needs Assessment, the Scoping Assessment (led by the IESO) recommended development of an IRRP to evaluate these and other capacity-related needs in the Renfrew Region and potential coordinated solutions to address them, including non-wires considerations for Pembroke TS.

Accordingly, the 2022 Renfrew IRRP led by the IESO focused on developing a plan to address identified capacity needs (Pembroke TS, Forest Lea DS, Petawawa DS) and supply capacity needs specific to the Des Joachims subsystem which includes the 115 kV D6 circuit. The IRRP identified several recommended actions including new transformer stations, distribution load transfers and monitoring of load growth in the Des Joachims sub-system. The IRRP's recommendations are summarized in Section 2 of the IRRP.[2]

At the time IRRP work was underway, the 115 kV D6 transmission line end-of-life refurbishment had already been identified through the Needs Assessment and was proceeding through Hydro One's asset renewal processes. The IRRP did not include new analysis specific to the refurbishment scope

[2] https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Renfrew/renfrew-IRRP-Report.pdf

as related work had already been commenced by Hydro One; the IRRP focused on the area's capacity issues and monitoring actions described above.

2.3 115 kV D6 Transmission Line Refurbishment as Documented in Regional Planning for Renfrew

Hydro One's Needs Assessment for the Renfrew Region, published in May 2021, and Hydro One's subsequent Regional Infrastructure Plan (RIP), released in July 2023, identified the need for refurbishment of the majority of the 115 kV D6 transmission line. This portion of the line extends approximately 76.8 kilometres from Des Joachims TS to Petawawa/Craig DS. Based on Hydro One's asset condition assessment, the refurbishment is required to address the deteriorated state of the line, with a planned in-service date of 2025. Hydro One reported in its 2021 Needs Assessment that refurbishment of the 115 kV D6 transmission line was already underway. The subsequent RIP confirmed both the project's progress and its targeted in-service date of 2025.

3. Linkages and Interdependencies with Regional Plans

The D6 115 kV circuit is the sole transmission supply from Des Joachims TS, serving multiple stations in the Renfrew area, including Des Joachims DS, Deep River DS, Craig DS, Forest Lea DS, and Petawawa DS. Its continued operability is therefore essential to maintain supply to existing load in this part of the region. Hydro One identified end-of-life refurbishment of approximately 76.8 km of D6 as required based on asset condition, with a planning-level in-service date of 2025. The IRRP acknowledged this previously identified D6 refurbishment but did not assess or recommend changes to it, as the work was already underway.

After completion of the last cycle of regional planning for Renfrew Region, and during RIP implementation activities, Hydro One advised that land access constraints along portions of the existing D6 right-of-way necessitated relocating segments of the line to complete the refurbishment. This represents a change to implementation (routing) and not to the planning need itself or to the function of the circuit.

Based on the information provided by Hydro One, the relocation is not expected to materially change the electrical characteristics relied upon in regional planning (i.e., the circuit's role, rating assumptions, or the regional planning recommended actions). It does not introduce a new regional capacity requirement, nor does it alter the interdependencies documented for the subsystem or the station-level recommendations for Pembroke TS, Forest Lea DS, or Petawawa DS.

The IESO confirms that the change in route enables the same asset-renewal outcome, maintaining supply on the only circuit serving these loads, without changing the needs, assumptions, or actions established through regional planning.

4. Conclusions

The IESO supports the proposed project as it is consistent with regional planning objectives for the Renfrew Region and necessary to maintain reliable supply on the only transmission circuit serving these loads.

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June 7, 2023

Hydro One Networks Inc.
Joe Zerdin, P.Eng.
Director, Large Customer Account Management
420 Welham Road,
Barrie, Ontario L4N 8Z2

Dear Mr. Zerdin,

Reference: Correspondence March 9, 2023
Subject: Refurbishment of Hydro One Transmission Line D6 within Garrison Petawawa lands,

If Hydro One wishes to proceed with the in-situ restoration on the existing corridor, Hydro One will have to follow the existing Defence Controlled Access Area Regulations Defence Controlled Access Area Regulations (justice.gc.ca). Hydro One will have to schedule their work as operational requirements for Canadian Armed Forces training permits. Based on the operational training schedule, Hydro One will not be able have continued/unrestricted access to Garrison Petawawa live-fire training area for 4-5 days at a time for 8-12 months in the foreseeable future.

DND proposes to provide an opportunity to benefit Hydro's maintenance program and reduce the cost of materials, equipment and labour by placing the transmission line adjacent to Hwy 17 on the former CP railbed reducing the distance from 26km to 22km. If Hydro chooses to move forward with the opportunity, I believe it will be mutually beneficial to all parties.

Respectfully,

KESSERWAN, FELIX 106
Digitally signed by KESSERWAN, FELIX 106
Date: 2023.06.14 12:14:51 -04'00'

Felix Kesserwan
Major
Officer Commanding
Real Properties Operations Detachment Petawawa

Canada

PROJECT CATEGORIZATION AND CLASSIFICATION

PROJECT CATEGORIZATION

Subsection 4.3.2.4 of the Board's Filing Requirements requires applicants to categorize projects as being either discretionary or non-discretionary. Non-discretionary project characteristics include:

a) mandatory requirements to satisfy reliability standards set by standards authorities including NPCC/NERC or the IESO;
b) a need to connect new load (of a distributor or large user) or new generation connection;
c) a need to address equipment loading or voltage/short circuit stresses when their rated capacities are exceeded;
d) a transmission project that the transmitter is required by its licence to develop and seek approvals for;
e) projects identified in a provincial government approved plan;
f) projects that are required to achieve provincial government objectives that are prescribed in governmental directives or regulations; and
g) priority transmission projects declared by Lieutenant Governor in Council order that the construction, expansion, or reinforcement of an electricity transmission line is needed as a priority project.

Based upon the above criteria, Hydro One submits that the Project is categorized as a discretionary project as it is work triggered by the need for circuit refurbishment given the current facility has reached its end of life. The Project will return the 115 kV D6 circuit section to 'as-new' condition, increasing the line's reliability and safety in the local area.

PROJECT CLASSIFICATION

Projects are classified into three groups based on their purpose.

- Development Projects, which most closely align with the System Service category as defined in Chapter 5 of the OEB Filing Requirements for Utility System Plans, are those which:
  i. provide an adequate supply capacity and/or maintain an acceptable or prescribed level of customer or system reliability for load growth or for meeting increased stresses on the system; or
  ii. enhance system efficiency such as minimizing congestion on the transmission system and reducing system losses.
- Connection Projects, which most closely align with the System Access category as defined in Chapter 5 of the OEB Filing Requirements for Utility System Plans, are those which provide connection of a load or generation customer or group of customers to the transmission system.
- Sustainment Projects, which most closely align with the System Renewal category as defined in Chapter 5 of the OEB Filing Requirements for Utility System Plans, are those which maintain the performance of the transmission network at its current standard or replace end-of-life facilities on a “like for like” basis.

Based on the above criteria, the Project is a Sustainment Project as the proposed transmission facilities provide for the need to refurbish existing assets given their age and poor condition and to maintain system capacity, reliability and quality of electricity supply.

Categorization and Classification

		Project Need	
		Non-Discretionary	Discretionary
Project Class	Development		
	Connection		
	Sustainment		X

COST BENEFIT ANALYSIS AND OPTIONS

There are no practical alternatives to the D6 Relocation Project scope of work for which Hydro One is seeking the OEB's approval, as described in **Exhibit B, Tab 3, Schedule 1.** Furthermore, as described in that Schedule, Hydro One completed the mandated Class EA process in accordance with Ontario's *Environmental Assessment Act, R.S.O. 1990, c. E.18,* and the defined route for the Project was determined in accordance with those requirements.

1.0 TRANSMISSION LINE ALTERNATIVES

Conductor Size Alternative Analysis

Hydro One undertook an analysis of the conductor size alternatives that would: (a) meet the supply needs in the Renfrew region and surrounding Pembroke/Des Joachims transmission corridor, and (b) be the optimal conductor size and rating, based on the expected load scenario in terms of line losses. The conductor alternatives evaluated were:

1. Alternative 1 – 411.4 kcmil ACSR/TW conductor
2. Alternative 2 – 477.0 kcmil ACSR conductor
3. Alternative 3 – 732.0 kcmil ACSR/TW conductor
4. Alternative 4 – 997.2 kcmil ACSR/TW conductor

Analysis and Recommendations

All alternatives listed above address the supply load need of the Project and provide a reliable supply to customers in the area. The following screening analysis considers the impact of line losses. The screening analysis summarized in Table 1 below was conducted in accordance with Hydro One's Transmission Line Loss Guideline.[1]

[1] As recently filed in proceeding EB-2023-0197, Exhibit I, Tab 2, Schedule 1, Attachment 1.

Table 1 – Project Line Loss Screening Analysis

	Alt. #1 (411.4 kcmil ACSR/TW)	**Alt. #2** (477.0 kcmil ACSR)	**Alt. #3** (732.0 kcmil ACSR/TW)	**Alt. #4** (997.2 kcmil ACSR/TW)
Net Capital Cost [2] **($M)**	37.13	37.69	38.98	39.68
Losses at Peak Flow [3] (MW)	0.897	0.773	0.508	0.376
Losses at System Peak (MW)	0.060	0.052	0.034	0.025
Annual Revenue Costs ($M)	2.81	2.85	2.95	3.01
Annual Cost of Capital to Cover Losses ($M)	0.0098	0.0085	0.0056	0.0041
Annual Cost of Energy Losses ($M)	0.418	0.360	0.236	0.175
Annual Cost of Losses [4] **($M)**	0.427	0.368	0.242	0.179
Total Annual Cost [5] **($M)**	3.24	3.22	3.19	3.18

The screening analysis, as shown in Table 1 above, resulted in a change in the alternative ranking, to the proposed conductor in this Application. This change resulted in a similar Total Annual Cost. As such a detailed 50-year net present value ("NPV") analysis was conducted. The NPV used a 5.65% discount rate, to evaluate which conductor alternative provided the best NPV result. The NPV sensitivity analysis used varying values for the prices of energy and a capacity price of $164,052/MW consistent with Hydro One's Transmission Line Loss Guideline.

[2] Net Capital Cost is the total Project cost net of removals; and was based on a project definition equivalent to a Class 3 under the AACE estimate classification system for all alternatives.
[3] Losses based on anticipate future forecast flows.
[4] Annual Cost of Losses is the summation of Annual Cost of Energy Losses (i.e. MWHR losses multiplied by the energy price) and the Annual Cost of Capital to Cover Losses (i.e. MW losses multiplied by Capacity Price).
[5] Total Annual Cost is the summation of Annual Revenue Costs and Annual Cost of Losses.

The results of the NPV sensitivity analysis are provided in Table 2 below.

Table 2 - NPV Sensitivity Analysis of Conductor Alternatives

	Alt. #1 (411.4 kcmil ACSR/TW)	**Alt. #2** (477.0 kcmil ACSR)	**Alt. #3** (732.0 kcmil ACSR/TW)	**Alt. #4** (997.2 kcmil ACSR/TW)
Net Capital Cost	37.13	37.69	38.98	39.68
Annual Losses (MWHR)	493	425	279	206
Losses at System Peak (MW)	0.060	0.052	0.034	0.025
Net Present Value ($M)				
Price	**Alt. #1** (411.4 kcmil ACSR/TW)	**Alt. #2** (477.0 kcmil ACSR)	**Alt. #3** (732 kcmil ACSR/TW)	**Alt. #4** (997.2 kcmil ACSR/TW)
Energy Price of $53.16/MWHR and Capacity Price of $164,052/MW	**-34.67**	-35.02	-35.85	-36.32
Energy Price of $120/MWHR and Capacity Price of $164,052/MW	**-35.49**	-35.72	-36.32	-36.66

The NPV analysis in Table 2 demonstrates that the Alternative #1 conductor is the most economically efficient alternative. All four alternatives meet the capacity needs for the area, however based on the analysis above, Alternative #1 is selected as the preferred and recommended alternative.

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QUANTITATIVE AND QUALITATIVE BENEFITS OF THE PROJECT

As detailed in **Exhibit B, Tab 3, Schedule 1** the relocation of these transmission line facilities will enhance overall accessibility, safety, and therefore minimize system reliability risk within the Project area. The Project reduces constraints on both utility operations and military activities.

The transmission system benefits delivered by the D6 Relocation Project are consistent with those documented in the IESO's *Supplemental Evidence to Support the Need for the 115 kV D6 Transmission Line Relocation Project* report as included at **Exhibit B, Tab 3, Schedule 1, Attachment 1.** In addition, though a definitive date of the existing electrical infrastructure's failure is impossible to predict precisely, this investment is intended to mitigate any safety and reliability risks associated with operating deteriorated assets including unplanned outages.

As outlined previously in this Application, Hydro One also conducted an economic analysis to investigate ratepayer impacts with respect to transmission line losses. The NPV sensitivity analysis confirms that the 411.4 kcmil ACSR/TW conductor is the most prudent conductor alternative to meet the needs of the D6 Relocation Project. The results of that analysis are discussed in **Exhibit B, Tab 5, Schedule 1**.

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APPORTIONING PROJECT COSTS AND RISKS

The estimated total capital cost of the D6 Relocation Project is $37.1M[1]. A breakdown of the capital cost estimate is shown below in Table 1 ("Project Cost").

Table 1 - Project Cost

	Estimated Cost ($000's)
Materials	$8,483
Labour	$10,976
Equipment Rental & Contractor Costs	$8,468
Sundry	$1,033
Contingencies	$2,927
Overhead	$2,522
Allowance for Funds Used During Construction [2]	$1,416
Real Estate	$1,309
Total Project Work[3]	**$37,135**

The Project Cost capital estimate was developed to allow for the approval, design and construction activities to proceed as set out in the Project schedule at **Exhibit B, Tab 11, Schedule 1** ("Project Schedule"). The Project Cost estimate was developed using a multi-faceted approach involving internal cost estimate tools and techniques, and a risk management model for the contingency allowance. The Project Cost estimate and the corresponding Project Schedule are based on a Project definition equivalent to a Class 3[4] under the Association for the Advancement of Cost Engineering ("AACE") International estimate classification system.

[1] There will be an additional $3.1M of OM&A removal costs associated with constructing this Project.
[2] AFUDC is calculated by applying the Board's approved interest rate methodology (EB-2016-0160) to the Project's forecast monthly cash flow and carrying forward closing balances from the preceding month.
[3] Total Project capital cost includes nominal station-related costs related to protection setting changes of approximately $169 k. Refer to Exhibit B, Tab 1, Schedule 1. Section 4 for more information.
[4] An estimate range of -20%/+30%

1.0 RISKS AND CONTINGENCIES

As with most projects, there are risks associated with estimating costs. Hydro One's Project Cost estimate includes an allowance for contingencies in recognition of these risks. Hydro One follows an industry established best practices methodology in developing the contingency utilizing a risk management model that includes both a qualitative and a quantitative risk analysis of identified risks to the Project.

The Project risks that predominantly contribute to the total contingency for this Project include the following:

- **Permits, Approvals and Authorizations:** Risk of delays or cost escalation in securing any required approvals including but not limited to leave to construct, necessary land rights, highway and rail crossing permits, and environmental approvals.
- **Procurement:** Risk to material lead times or material price increases that may cause schedule disruptions and increased cost.
- **Subsurface Conditions:** Risk of unforeseen underground obstructions or environmental conditions requiring additional mitigations that will have a cost impact and could delay the Project progress.
- **Outage Constraints:** Risk of limited availability of required system outages during summer and winter peak demand periods, which may restrict cutover and commissioning activities, increase scheduling complexity, and potentially delay overall Project progress.

To mitigate the above-mentioned risks Hydro One has implanted the following measures:

1. Established early and continuous engagement with all impacted stakeholders to maintain transparent communication, proactively address potential issues, and mitigate the risk of Project delays. Through this approach Hydro One has secured all land rights to deliver the Project voluntarily from the affected property owners.
2. Proactively submitted all regulatory applications, Project permits and authorizations sufficiently in advance of the construction start to ensure timely approvals.

3. Initiated procurement of long-lead materials (i.e. steel structures, conductor, OPGW) in advance of the construction start and established continuous communication with the material vendor,
4. Conducted preliminary studies and testing (e.g., boreholes and soil sampling) to identify subsurface conditions and develop implementation plans to address any risks encountered during construction,
5. Factored outage planning into the planning and scheduling phase of the Project to ensure critical activities that are outage-dependent are appropriately considered in the Project Schedule provided at **Exhibit B, Tab 11, Schedule 1.** The Project Schedule currently anticipates Project completion and energization of the new circuit in April 2028.

Certain cost contingencies have not been included in the total contingency for this Project, due to the unlikelihood or uncertainty of occurrence, including:

- Labour disputes,
- Safety or environmental incidents,
- Significant changes in costs and/or availability of materials outside the control of Hydro One, and
- Any other unforeseen and potentially significant event/occurrence.

2.0 COSTS OF COMPARABLE PROJECTS

The OEB Filing Requirements for *Electricity Transmission Applications, Chapter 4*, requires the Applicant to provide information about a cost comparable project constructed by the Applicant. Table 2, below, compares the line cost of the Project with three other recent comparable projects. Hydro One has delivered a relatively limited number of 115 kV greenfield transmission line projects recently, which limits the availability of directly comparable baseline projects. Accordingly, Table 2 compares the line cost of the D6 Relocation Project against three 115 kV refurbishment projects that include the installation of new structures and conductors and, in some cases construction along a new ROW. While these projects differ in overall scope, they represent the most reasonable and

informative cost comparators available, based on similarity in voltage class, construction methods, structure types, geographic setting, and recent in-service dates.

- **K4 Transmission Line Refurbishment Project ("K4 Refurbishment Project") between Kirkland Lake TS and Matachewan JCT**: Refurbishment of a 10 km line section of an existing 115kV single-circuit wood pole transmission line (Circuit nomenclature 'K4') that connects Kirkland Lake TS and Young–Davidson CTS. The project consisted of two sections: the first section included the replacement of conductors, all supporting wood pole H-frame structures, and associated hardware along the existing circuit ROW; and the second section involved construction of a single-circuit transmission line on H-frame wood pole structures along a new ROW east of the existing line. Leave to construct approval for this project was granted under OEB docket EB-2023-0197.
- **X2Y Transmission Line Refurbishment Project ("X2Y Refurbishment Project") between Magellan Aerospace CTS and IPB Bryson JCT**: Refurbishment of a 7.6 km line section of an existing 115 kV single-circuit wood pole transmission line (Circuit nomenclature 'X2Y') between Magellan Aerospace CTS and IPB Bryson Junction. The project included the replacement of conductors, all supporting structures, and associated hardware. The project was not subject to leave to construct approval by the OEB.
- **D6 Transmission Line Refurbishment Project ("D6 Line Refurbishment Project") between Des Joachims TS X Chalk River JCT and Petawawa JCT X Craig JCT/Petawawa DS**: In-situ sustainment of 48 km of existing 115 kV single-circuit wood pole transmission line (Circuit nomenclature 'D6') between Des Joachims TS X Chalk River JCT and Petawawa JCT X Craig JCT/Petawawa DS. This project included replacement of conductors, all supporting structures (using a combination of composite and wood due to pole damage risk from woodpecker bird species), and associated hardware. The project was not subject to leave to construct approval by the OEB.

The above projects were selected as reasonable comparators as they share key characteristics with the D6 Relocation Project. Specifically, all involve 115 kV single-circuit transmission lines, utilize composite pole structures, and are located in predominantly rural environments. In addition, each project involved substantial replacement or installation of line structures and conductors, making them appropriate benchmarks for comparing unit line costs despite differences in overall project scope.

For the purposes of the cost comparison presented in Table 2, Hydro One has adjusted the total project costs to exclude specific cost elements that are project specific, noncomparable, or driven by scope differences. These adjustments are necessary to facilitate a reasonable comparison of underlying line unit costs across projects. These adjustments generally cover differences between the projects in relation to real estate, structure type, forestry clearing needs, conductor size, project execution needs and in-service date, as more specifically described below.

Although real estate costs are excluded from the comparison provided in Table 2, the costs are reasonable as the real estate estimate for the D6 Relocation Project is supported by independent third-party appraisals. Both the K4 Refurbishment Project and D6 Relocation Project required significant real estate activities, including the acquisition of new easements and associated land rights and construction of transmission line segments along new or modified ROW.

Adjustments were also made to account for variations in structure types that are driven by project specific technical and site conditions, which are not representative of the facilities included in the comparable refurbishment projects. These adjustments relate to the use of composite pole structures and steel structures included in the D6 Relocation Project. Installation of these structures necessitates gravel access routes and specialized equipment, resulting in incremental construction costs that are not applicable to the comparable projects which predominantly utilize conventional wood pole structures.

Installation of steel structures, which is required for the D6 Relocation Project, is more complex than wood pole construction and requires larger equipment, increased site preparation, and additional construction activities to safely erect and assemble the structures. These requirements result in additional planning efforts needed for construction and increased costs relative to wood pole installations. In addition, steel structures are required for the D6 Relocation Project to accommodate the planned Highway 17 expansion by the MTO. Based on results from Project specific geotechnical investigations, shallow foundations were determined to be unsuitable due to bedrock conditions along portions of the route. As a result, micropile foundations are required for steel structures to ensure structural stability and long-term performance. These foundation requirements are unique to the D6 Relocation Project and were therefore excluded from the cost comparison.

Similarly, adjustments were made to account for the forestry costs associated with the clearing of a new ROW, which is specific to the D6 Relocation Project. These costs are not present, or are materially different in nature and scale, in refurbishment projects constructed largely within existing corridors.

In addition, rider poles were also required on the K4 Refurbishment Project and the D6 Relocation Project to facilitate conductor stringing across road crossings, Highway crossings, and distribution circuit crossings. These temporary rider poles were installed to maintain required electrical clearances and ensure public and worker safety during stringing and tensioning activities.

An adjustment was also made to exclude costs associated with the larger 997.2 kcmil ACSR/TW conductor used in the K4 Refurbishment Project. The larger conductor size and associated hardware result in higher material and installation costs compared to the 411.4 kcmil ACSR/TW conductor used for the D6 Relocation Project and the other comparable projects. Excluding this cost ensures consistency in conductor assumptions across the comparison.

The variances in the unadjusted per/km cost to execute these projects is driven by the timing differences in the in-service date. Therefore, Table 2 has been adjusted to show comparable projects in 2028 dollars utilizing inflation values for future years consistent with the inflation parameters provided by the OEB.

When considering the adjusted comparable cost per km ratio for all other transmission line costs in Table 2, the comparable projects demonstrate that the estimate for the D6 Relocation Project is consistent with the cost to complete comparable transmission line works and is reasonable.

Table 2 - Cost of Comparable Line Projects

Project	K4 Refurbishment Project (Line Cost)	X2Y Refurbishment Project (Line Cost)	D6 Refurbishment Project (Historical) (Line Cost)	D6 Relocation Project
Circuit Operating Designation(s)	K4	X2Y	D6	D6
D6Voltage	115 kV	115 kV	115 kV	115 kV
Structure Type	Wood pole (H-Frame / Single-Pole)	Wood pole (Single-Pole)	Wood/Composite Poles (Primarily H-Frame Wood)	Composite pole (Primarily H-Frame)/Steel Structures
Single or Double Circuit	Single	Single	Single	Single
Conductor	997.2 kcmil ASCR/TW	411.4 kcmil ACSR/TW	411.4 kcmil ACSR/TW	411.4 kcmil ACSR/TW
Location	Northern	Eastern	Northern	Northern
Project Surroundings	Rural	Rural	Rural	Rural
In-Service Year	2024	2020	2022	2028
Estimate or Actual	Actual	Actual	Actual	Estimate
OEB-Approved Cost Estimate	$13.9M[5]	N/A[6]	N/A[7]	N/A
Total Cost	**$12,403K**	**$5,100K**	**$34,700K**	**$37,135K**
Less Adjustments:				
Real Estate	*$1,464K*	*N/A*	*N/A*	*$1,738K[8]*
Structure Type Variations - Composite	*N/A*	*N/A*	*$554K*	*$2,973K*
Structure Type Variations –	*$120K*	*N/A*	*N/A*	*$10,805K*

[5] As per Section 92 leave to construct proceeding EB-2023-0197.
[6] 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.
[7] 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.
[8] This amount includes the direct real estate costs of $1,309 K (as per the Real Estate cost category in Table 1 above) plus applicable contingency, interest and overhead costs.

Steel Structures				
Forestry	*$292K*	*N/A*	*N/A*	*$2,874K*
Install and removal Rider poles / By Pass	*$156K*	*N/A*	*N/A*	*$121K*
Larger Conductor (997.2 kcmil) and Associated Hardware	*$190K*	*N/A*	*N/A*	*N/A*
Station Costs	*N/A*	*N/A*	*N/A*	*$169K*
Comparable Costs, before Escalation	**$10,181K**	**$5,100K**	**$34,146K**	**$18,455K**
Escalation Adjustment[9]	$1,415K	$1,467K	$7,925K	N/A
Total Adjusted Comparable Cost	**$11,596K**	**$6,567K**	**$42,071K**	**$18,455K**
Approximate Length	10.0 km	7.6 km	48.0 km	21.0 km
Unit Cost	**$1,160K/km**	**$864K/km**	**$876K/km**	**$879K/km**

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

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CONNECTION PROJECTS REQUIRING NETWORK REINFORCEMENT

This is not a connection project. The line facilities being refurbished/relocated as part of this Project are limited to those discussed in the details of the work being undertaken in **Exhibit C, Tab 1, Schedule 1.**

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TRANSMISSION RATE IMPACT ASSESSMENT

1.0 ECONOMIC FEASIBILITY

Based on Project scope, as described in this Application, the Project's costs will be included in the line connection pool for cost classification and recovery purposes and are not allocated to any individual customer. This Project is classified as a sustainment project based on the identified need to refurbish existing assets given their age and poor condition and to maintain system capacity, reliability and quality of electricity. As such, no customer contribution is required for the Project.

A 25-year discounted cash flow analysis of the line connection pool work demonstrates that based on the estimated initial total Project cost of $40.2 million[1], plus the assumed impact on the future capital cost allowance, Hydro One's corporate income tax and zero annual incremental line connection revenue utilizing the 2026 UTR over a 25-year evaluation period, this Project will have a negative net present value of $34.9 million as shown in Tables 2 and 3, below.

2.0 COST RESPONSIBILITY

Line Connection Pool

Based on the cost allocation methodology approved by the Board in Hydro One's most recent transmission rate filing, the line assets are allocated 100% to the Line Connection Pool.

3.0 RATE IMPACT ASSESSMENT

The analysis of the line connection pool rate impact has been carried out on the basis of Hydro One's transmission revenue requirement for the year 2026, and the 2026 approved Ontario Uniform Transmission Rate ("UTR") Schedules. The line connection pool revenue requirements would be affected by the Project based on the Project's cost allocation.

[1] The total line connection costs of $40.2 million includes $37.1 million of up-front capital costs plus $3.1 million of removal costs.

Line Connection Pool

Based on the estimated total cost of $40.2 million and the associated line pool incremental cash flows, the line pool revenue requirement will change once the Project's impacts are reflected in the transmission rate base at the projected in-service date of December 2027. The 2026 OEB approved rate of $1.03 per kW/month increases to $1.04 per kW/month over a 25-year time horizon. The detailed analysis illustrating the calculation of the incremental line revenue and rate impact is provided in Tables 4 and 5 below.

Impact on Typical Residential Customer

Based on the load forecast, initial capital costs and ongoing maintenance costs, adding the costs of the required facilities to the line connection pool will cause a $0.02 (or 0.01%) per month increase in a typical residential customer's bills under the Regulated Price Plan ("RPP"). Table 1 below shows this result for a typical residential customer who is under the RPP, utilizing the maximum impact by rate pool, regardless of year.

Table 1 - Rate Impact on Typical Residential Customer Bill

A. Typical monthly bill	$168.81 per month
B. Transmission component of monthly bill	$18.08 per month
C. Line Connection Pool share of Transmission component	$1.74 per month
D. Transformation Connection Pool share of Transmission component	$5.85 per month
E. Network Connection Pool share of Transmission component	$10.49 per month
F. Impact on Line Connection Pool Provincial Uniform Rates	0.97%
G. Impact on Transformation Connection Pool Provincial Uniform Rates	0.00%
H. Impact on Network Connection Pool Provincial Uniform Rates	0.00%
I. Increase in Transmission costs for typical monthly bill (C x F + D x G + E x H)	$0.02 per month or $0.2 per year
J. Net increase on typical residential customer bill (I / A)	0.01%

1

Table 2 - Net Present Value, Line Pool page 1

Date:	7-May-26
Project #	24294

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Hydro One Transmission Circuit D6
Description:	Partial relocation of transmission circuit D6
Customer:	None

			In-Service Date	<------- Project year ended - annualized from In-Service Date -------->												
		Month	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15
		Year	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	
			0	1	2	3	4	5	6	7	8	9	10	11	12	
Revenue & Expense Forecast																
Load Forecast (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Tariff Applied ($/kW/Month)				1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	
Incremental Revenue - $M				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Removal Costs - $M			(3.1)													
On-going OM&A Costs - $M			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	
Municipal Tax - $M				(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	
Net Revenue/(Costs) before taxes - $M			(3.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	
Income Taxes			0.8	0.4	0.8	0.7	0.7	0.6	0.6	0.5	0.5	0.5	0.4	0.4	0.4	
Operating Cash Flow (after taxes) - $M			(2.3)	0.3	0.7	0.6	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.2	
		Cumulative PV @ 5.65%														
PV Operating Cash Flow (after taxes) - $M	**(A)**	**2.1**	**(2.3)**	**0.3**	**0.6**	**0.5**	**0.4**	**0.4**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**	
Capital Expenditures - $M																
Upfront - capital cost before overheads & AFUDC			(33.0)													
- Overheads			(2.7)													
- AFUDC			(1.4)													
Total upfront capital expenditures			**(37.1)**													
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
PV On-going capital expenditures			0.0													
Total capital expenditures - $M			**(37.1)**													
Capital Expenditures - $M																
PV CCA Residual Tax Shield - $M			**0.2**													
PV Working Capital - $M			**0.0**													
PV Capital (after taxes) - $M	**(B)**	**(36.9)**	**(36.9)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(34.9)**	**(39.2)**	**(38.9)**	**(38.3)**	**(37.8)**	**(37.3)**	**(36.9)**	**(36.6)**	**(36.3)**	**(36.1)**	**(35.9)**	**(35.7)**	**(35.6)**	**(35.4)**	

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**
Discount Rate - %		**5.65%**
		$M
PV Incremental Revenue		0.0
PV OM&A Costs		(3.1)
PV Municipal Tax		(1.7)
PV Income Taxes		1.3
PV CCA Tax Shield		5.7
PV Capital - Upfront	(37.1)	
Add: PV **Capital Contribution**	**0.0**	(37.1)
PV Capital - On-going		0.0
PV Working Capital		0.0
PV Surplus / (Shortfall)		**(34.9)**
Profitability Index*		**0.1**

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

Other Assumptions

In-Service Date:	15-Dec-27
Payback Year:	2052
No. of years required for payback:	25

Table 3 - Net Present Value, Line Pool, Page 2

Date:	7-May-26
Project #	24294

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Hydro One Transmission Circuit D6
Description:	Partial relocation of transmission circuit D6
Customer:	None

	Month	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15	Dec-15
	Year	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**
		13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast														
Load Forecast (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		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
Tariff Applied ($/kW/Month)		1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03
Incremental Revenue - $M		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
Removal Costs - $M														
On-going OM&A Costs - $M		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
Municipal Tax - $M		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Income Taxes		0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
Operating Cash Flow (after taxes) - $M		0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(35.3)**	**(35.2)**	**(35.2)**	**(35.1)**	**(35.1)**	**(35.0)**	**(35.0)**	**(34.9)**	**(34.9)**	**(34.9)**	**(34.9)**	**(34.9)**	**(34.9)**

Table 4 - Revenue Requirement and Line Connection Pool Rate Impact, Page 1

Revenue Requirement and Line Pool Rate Impact

Hydro One Transmission Circuit D6		Project YE 15-Dec 2028	15-Dec 2029	15-Dec 2030	15-Dec 2031	15-Dec 2032	15-Dec 2033	15-Dec 2034	15-Dec 2035	15-Dec 2036	15-Dec 2037	15-Dec 2038	15-Dec 2039
Calculation of Incremental Revenue Requirement ($ millions)		1	2	3	4	5	6	7	8	9	10	11	12
In-service date	15-Dec-27												
Capital Cost	37.1												
Less: Capital Contribution Required	-												
Net Project Capital Cost	37.1												
Average Rate Base		18.2	36.0	35.3	34.5	33.8	33.0	32.3	31.6	30.8	30.1	29.3	28.6
Incremental OM&A Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grants in Lieu of Municipal tax		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Depreciation		0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Interest and Return on Rate Base		1.2	2.3	2.2	2.2	2.1	2.1	2.0	2.0	2.0	1.9	1.9	1.8
Income Tax Provision		(0.0)	(0.3)	(0.2)	(0.1)	(0.1)	(0.0)	0.0	0.1	0.1	0.1	0.2	0.2
REVENUE REQUIREMENT PRE-TAX		**2.0**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**
Incremental Revenue		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SUFFICIENCY/(DEFICIENCY)		**(2.0)**	**(2.9)**	**(2.9)**	**(2.9)**	**(2.9)**	**(2.9)**	**(2.9)**	**(2.9)**	**(2.9)**	**(2.9)**	**(2.9)**	**(2.9)**
	Base Year												
Line Pool Revenue Requirement including sufficiency/(deficiency)	232	234	235	235	235	235	235	235	235	235	235	235	235
Line MW	226	226	226	226	226	226	226	226	226	226	226	226	226
Line Pool Rate ($/kw/month)	1.03	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Increase/(Decrease) in Line Pool Rate ($/kw/month), relative to base year		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
RATE IMPACT relative to base year		**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**

Assumptions

Incremental OM&A		$3.68037852575368 k per new km of line each year.
Grants in Lieu of Municipal tax	0.33%	Transmission system average
Depreciation	2.00%	Reflects 50 year average service life for towers, conductors and station equipment, excluding land
Interest and Return on Rate Base	6.34%	Includes OEB-approved ROE of 9.36%, 4.79% on ST debt, and 4.3% on LT debt. 40/4/56 equity/ST debt/ LT debt split
Income Tax Provision	26.50%	2026 federal and provincial corporate income tax rate
Capital Cost Allowance	8.00%	96.5% Class 47 assets

Table 5 - Revenue Requirement and Line Connection Pool Rate Impact, Page 2

Revenue Requirement and Line Pool Rate Impact

Hydro One Transmission Circuit D6		15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec	15-Dec
		2040	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**
Calculation of Incremental Revenue Requirement ($ millions)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	15-Dec-27													
Capital Cost	37.1													
Less: Capital Contribution Required	-													
Net Project Capital Cost	37.1													
Average Rate Base		27.9	27.1	26.4	25.6	24.9	24.1	23.4	22.7	21.9	21.2	20.4	19.7	18.9
Incremental OM&A Costs		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
Grants in Lieu of Municipal tax		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Depreciation		0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Interest and Return on Rate Base		1.8	1.7	1.7	1.6	1.6	1.5	1.5	1.4	1.4	1.3	1.3	1.2	1.2
Income Tax Provision		0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
REVENUE REQUIREMENT PRE-TAX		**2.9**	**2.8**	**2.8**	**2.8**	**2.8**	**2.7**	**2.7**	**2.6**	**2.6**	**2.6**	**2.5**	**2.5**	**2.4**
Incremental Revenue		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
SUFFICIENCY/(DEFICIENCY)		**(2.9)**	**(2.8)**	**(2.8)**	**(2.8)**	**(2.8)**	**(2.7)**	**(2.7)**	**(2.6)**	**(2.6)**	**(2.6)**	**(2.5)**	**(2.5)**	**(2.4)**
	Base Year													
Line Pool Revenue Requirement including sufficiency/(deficiency)	232	235	235	235	235	235	235	235	235	235	235	235	235	235
Line MW	226	226	226	226	226	226	226	226	226	226	226	226	226	226
Line Pool Rate ($/kw/month)	1.03	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Increase/(Decrease) in Line Pool Rate ($/kw/month), relative to base year		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
RATE IMPACT relative to base year		**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**	**0.97%**

1

Table 6 - DCF Assumptions

Hydro One Networks -- Transmission Connection Economic Evaluation Model
2026 Parameters and Assumptions

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

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

Grants in lieu of Municipal tax (% of up-front capital expenditure, a proxy for property value):		**0.33%**	Based on Transmission system average
Income taxes:			
Basic Federal Tax Rate - % of taxable income:	2026	**15.00%**	Current rate
Ontario corporation income tax - % of taxable income:	2026	**11.50%**	Current rate
Capital Cost Allowance Rate:			
Class 47 costs	2026	**8%**	Current rate
Easement rights	2026	**5%**	
Decision Support defined costs (2)	2026	**0%**	
Decision Support defined costs (3)	2026	**0%**	
After-tax Discount rate:		**5.65%**	Based on OEB-approved ROE of 9.36% on common equity and 4.79% on short-term debt, 4.3% forecast cost of long-term debt and 40/60 equity/debt split, and current enacted income tax rate of 26.5%

REVENUE REQUIREMENT INFORMATION AND DEFERRAL ACCOUNT REQUESTS

1.0 REVENUE REQUIREMENT AND TRANSMISSION SYSTEM PLAN INFORMATION

The Project, as contemplated, has never been considered in a prior Hydro One revenue requirement application.

For completeness, Hydro One's 2020-2022 Transmission revenue requirement application (docket EB-2019-0082) identified the D6 circuit for refurbishment in Investment Summary Document ("ISD") SR-19[1] (**Attachment 1** to this Schedule). The refurbishment project outlined in SR-19 anticipated the in-situ sustainment and renewal of the entire circuit that had been identified for refurbishment, being approximately 77 km of transmission facilities. However, for the safety and operational reasons detailed in **Exhibit B, Tab 3, Schedule 1,** the segment of the circuit that traverses the DND training grounds were halted at the request of the DND and required the initiation of a completely different project – the D6 Relocation Project – which has never been incorporated into Hydro One revenue requirement application.

2.0 DEFERRAL ACCOUNT REQUEST INFORMATION

There are no new deferral or variance account requests being made as part of this Application.

[1] EB-2019-0082 – Hydro One's Revenue Requirement Application for Transmission rates for 2020 to 2022, Exhibit B-1-1, ISD SR-19, page 13 of 15.

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SR-19 Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures

Start Date:	Q4 2015	**Priority:**	High
In-Service Date:	Q4 2025	**3 Year Test Period Cost ($M):**	298.4
Trigger(s):	Strategic, System Renewal		
Outcomes:	Improve system reliability, minimize customer outages, reduce maintenance costs associated with the EOL assets, realize cost savings and efficiencies as a result of bundling needed work within this investment		

A. OVERVIEW

This set of Transmission Line Refurbishment Projects involve the replacement of all End-Of-Life ("EOL") components along all or part of a line section. These projects are driven by the need to replace major transmission line components, verified to be at EOL by condition assessment, including Aluminum Conductor Steel Reinforced ("ACSR") conductor, obsolete copper conductor, or deteriorated structures in high risk condition.

These assets pose safety and system reliability risks should they fail. In addition, copper conductors are the oldest type of overhead conductors in the Hydro One transmission system and are now obsolete. Hydro One is no longer able to mend some broken copper conductors due to this obsolescence. These Line Refurbishment Projects aim to remove and replace these deteriorated EOL conductors, or refurbish high risk structures to sustain safe and reliable delivery of electricity. Hydro One has evaluated various alternatives for these Projects, as described below, and concluded that replacing the EOL deteriorated ACSR, obsolete copper conductors, or refurbishing deteriorated structures is the most cost effective and efficient undertaking for sustaining these assets. The projected cost of these Projects is estimated to be $298.4 million over the 2020-2022 test period.

B NEED AND OUTCOME

Investment Need

Long transmission circuits are required to deliver power across Hydro One's vast territory. These transmission assets are exposed to environmental stresses, including severe weather and temperature variations that degrade equipment over time.

Hydro One has approximately 29,000 circuit kilometres of high-voltage transmission conductors. Over 99% of Hydro One's transmission system is comprised of overhead power lines. The conductor of an overhead transmission line is the single largest and most vulnerable component. Close to 98% of Hydro One's overhead conductor fleet utilizes ACSR conductors, with copper, aluminum, and aluminum conductor steel supported ("ACSS") types making up the balance.

Hydro One defines Expected Service Life ("ESL") as the average age in years that an asset can be expected to operate under normal system conditions. Hydro One also defines End of Life ("EOL") as the state of having a high likelihood of failure, or loss of an asset's ability to provide the intended functionality. EOL state is established only through testing, where an asset is empirically verified to have deteriorated to a point where its ability to perform is compromised. A conductor in a deteriorated condition translates to a loss of mechanical strength or ductility, resulting in the conductor possessing a greater likelihood of breaking and dropping. EOL is always determined by condition assessment.

Hydro One uses an ESL of 90 years for overhead transmission conductors, although the life span of each conductor can vary between 50 and 120 years, as numerous uncontrollable variables affect conductor deterioration, including manufacturing material quality, location, orientation, local atmospheric pollution levels, weather cycles and stringing tension. Currently, about 5% of the overhead conductor fleet has reached or exceeded their ESL of 90 years.

Table 1 below summarizes the demographic profile of the overhead conductor fleet. Without any further replacements, the percentage of conductors exceeding ESL will increase to 13% by end of 2024.

Table 1 - Overhead Conductor Demographics

Conductor Type	Circuit km in Service	Average Age (Years)	ESL (Years)	Beyond ESL	Beyond ESL 2024	Beyond ESL 2029
ACSR	28,437	54	90	876	3,125	3,988
Copper	512	97	70	512	512	512
Aluminum	21	89	100	0	15	15
ACSS	137	26	N/A*	0	0	0
Total	**29,107**	**55**		**1,389**	**3,653**	**4,516**

** Relatively new conductor type to Hydro One, limited installation, ESL to be established*

Hydro One operates a condition assessment program to determine the condition of conductors that are beyond 50 years of age. Presently, condition assessment results indicate that about 3,680 km, or 13% of the conductor fleet is known to be at high risk as outlined in Figure 1. This includes lines with ACSR conductors and structures verified to be in high risk condition through testing, and copper conductors, many of which suffer from damage caused by lightning strikes, mechanical strength loss and can no longer be repaired due to obsolete repair components.

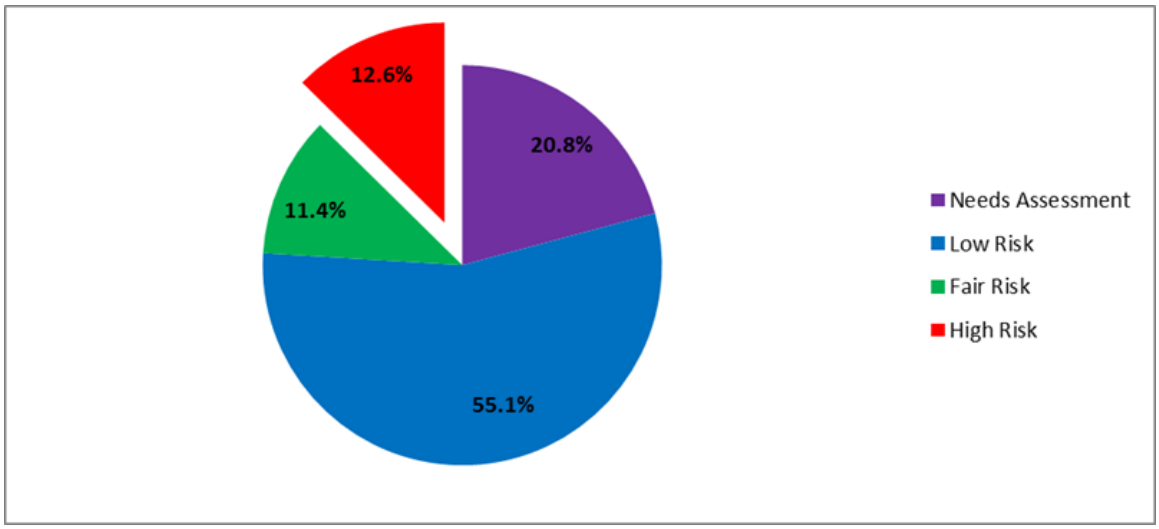


Figure 1 - Distribution of Overhead Conductor Condition

ACSR conductors consist of aluminum strands that surround galvanized steel strands, referred to as the core. Once the galvanized coating of the core wears off, for example as a result of weather or strand movement, the exposed steel strands corrode quickly, resulting in a loss of tensile strength or ductility. Deterioration of tensile strength results in a failure to hold required loads, while deterioration in ductility, makes the conductor brittle, making the suspended conductor which is moved by wind forces susceptible to cracking and breaking, as shown in Figure 2.



Figure 2 - Broken ACSR Conductor

Less than 2% of Hydro One conductor fleet is Copper conductor. Copper conductors are the oldest conductor type Hydro One has in its Network. Although copper conductors are not as susceptible to deterioration from corrosion when compared to ACSR conductors, this type of conductor has been exposed to the elements for a much longer time and many suffer from damage caused by lightning strikes. Figure 3 illustrates a dissected Hydro One copper conductor revealing a plant fibre core. This conductor type cannot be spliced and therefore its failure would result in the need to replace an entire dead-end to dead-end span, needing extensive resources and financing to perform on an unplanned emergency basis.

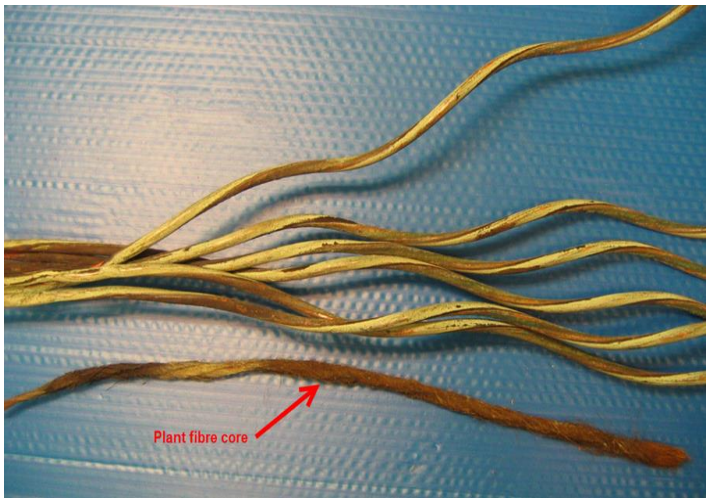


Figure 3 - Dissected copper conductor

The breaking of a conductor will lead to the overhead suspended conductor dropping, potentially along with its hardware as shown in Figure 4 below. A broken and dropped conductor will result in an outage to the circuit and endangers all in proximity of its fall. A typical transmission line spans 300 m at a rough height of 30 meters. At about 1.6 kg/m, a falling conductor span is equivalent to a 480 kg metallic mass falling from 30 m above. Potential damage as a result of this fall is demonstrated in Figure 5 below. In some cases a broken conductor can remain energized, which presents an added danger of electrocution and fire hazard to its surroundings.



Figure 4 - Fallen span of conductor



Figure 5 - Damage from a fallen conductor

Figure 5 shows a fallen conductor as a result of an insulator failure. Although the cause of this conductor dropping was not the breakage of the actual conductor, the result would be the same.

Line refurbishment projects are triggered by a confirmed need to replace the conductor or in a minority of cases, extensive structure deterioration, along a line section. This confirmation comes empirically through testing which confirms a deteriorated condition of the conductor or structure. Work plans to perform the replacement of EOL conductors or refurbishment of structures also consider the replacement or refurbishment of all other line components. As such, a conductor replacement project frequently includes the refurbishment of all major components within that line section, based on an assessment of the line's structures, shieldwire, insulators and hardware.

During the development of a line refurbishment project, the line section targeted for conductor replacement is surveyed, at which point other assets that are at EOL or near EOL are identified and also targeted for replacement. Components in good condition are not refurbished or replaced. Bundling conductor replacement with the replacement or refurbishment of other components is cost effective.

Presently, the Hydro One overhead transmission system has 3,680 km of conductor known to be in high risk condition, as verified empirically through condition assessment. Of this set of identified high risk conductors, 859 km, or 23% of the known high risk population have been planned and packaged into refurbishment projects that address conductors confirmed to be in EOL condition during the planning period. Confirmed EOL lines, as opposed to confirmed Near EOL lines, have deteriorated further, and therefore present the greatest risk of failure.

Investment Description

Table 2, Table 3, Table 4, and Table 5 present the set of material projects that aim to completely refurbish the listed sections of the circuits. Hydro One has confirmed, through condition assessment that these line sections have deteriorated to the extent that their conductor or structure has reached EOL and, as such, require replacement or refurbishment.

The project list below also includes a "placeholder" line item that allocates funding for packaging an additional 456 km, or 12% of verified high risk conductors in addition to the planned and packaged 859 km of EOL projects. This is intended to reserve funding for conductors that are confirmed to be at EOL but are still undergoing the planning process. As an example, some of these projects are under review by Hydro One System Development group to verify whether a sustainment based project is the most appropriate approach to address the short and long term system requirements. The projected cost for forecast projects are based on a historical average cost for line refurbishment projects which is being used for planning purposes prior to formal project estimation.

Each project will entail an assessment of all assets along the line section and the replacement or refurbishment of all components that are deemed at or near EOL. These components might include shieldwire, insulators or hardware, to comprehensively renew the line as a whole. In addition, all structures and foundations will be refurbished as required.

Bundling conductor replacement with the replacement/refurbishment of other components is cost effective. Bundled work does not mean replacing assets that are in good condition. The development of a line refurbishment project, through budgetary and detailed estimation stages, which collectively average 18 months, is used to identify which other assets have also limited service life and can benefit from replacement, while work crews are already deployed to replace the conductor.

Table 2 - Line Refurbishment Projects Driven by EOL ACSR Conductors

Project	Circuit km of Project during planning period
B5/6C, BurlingtonTS X WestoverCTS, Tx Line Refurb.	0 (project in-execution, majority replaced prior to 2020)
D2L, Upper Notch JCT X Martin River JCT, Line Refurb.	0 (project in-execution, majority replaced prior to 2020)
E1C, Ear Falls TS X Slate Falls DS + Etruscan JCT X Crow River DS, Line Refurb.	162
H1L/H3L/H6LC/H8LC, Bloor Street JCT X Leaside 34 JCT, Line Refurb.	8
D6, Des Joachims JCT X Tee Lake JCT + Chalk River JCT X Petawawa JCT, Line Refurb.	77

Table 3 - Line Refurbishment Projects Driven by Obsolete Copper Conductors

Project	Circuit km of Project during planning period
D3A, Allanburg TS X AWS Steel CTS, Tx Line Refurb.	0 (project in-execution, majority replaced prior to 2020)
B3/B4, Horning Mountain JCT X Glanford JCT, Tx Line Refurb.	22
A8K/A9K, Str. 141 JCT X Kirkland Lake TS, Tx Line Refurb.	112
A7L/R1LB & 57M1, Alexander B JCT X Lakehead TS & Nipigon JCT, Tx Line Refurb.	227
K1/K2, Kirkland Lake TS X Holloway Holt JCT, Tx Line Refurb.	14
D2/3H & D4 & D6T, Hunta SS X Abitibi Canyon SS, Tx Line Refurb.	183
Q2AH, Rosedene JCT X St.Anns JCT, Tx Line Refurb.	22

Table 4 - Line Refurbishments Project Driven by Deteriorated Structures

Project	Circuit km of Project during planning period
N21W/N22W, Sarnia Scott TS X Buchanan TS, Tx Str. Refurb.	0 (no conductor replaced)

Table 5 - Forecast for Expected Line Refurbishment Need Discoveries

Project	Circuit km of Project during planning period
Tx Line Refurb: Placeholder, Expected EoL Line Discoveries	456

Outcome

The following table presents anticipated benefits as a result of the aforementioned Projects in accordance with the OEB's Renewed Regulatory Framework:

Customer Focus	• Replacement of EOL conductors decreases the likelihood of their failure. Decreased likelihood of conductor failure results in a decreased likelihood of an outage to the customer.
Operational Effectiveness	• Operating a circuit with EOL conductors subjects that circuit to an increased likelihood of failure, which directly threatens reliable operation of the system. Line refurbishment will alleviate this threat.
Public Policy Responsiveness	• Decreased likelihood of failure reduces the likelihood of a conductor dropping and potentially causing injury to public or employees, damaging property or damaging local environment (fire caused by dropped energized conductor)
Financial Performance	• Realize cost savings by bundling conductor replacement with associated deteriorated line components as part of the same project.

C. EXPENDITURE PLAN

As discussed above, Line Refurbishment Projects are needed to replace/refurbish the EOL ACSR conductors, obsolete copper conductors and line sections with deteriorated structures, in order to mitigate the risk to safety and reliability that would result from their failure. Hydro One planned these projects in a way that strives to complete it as effectively and efficiently as possible to minimize the cost of performing this sustainment need.

Table 6 summarizes historical and projected spending on the aggregate. The "Previous Years" costs are the direct project costs for projects noted above that have incurred costs prior to the 2020 test year. Likewise, the costs noted in "Forecast 2025+" are project costs forecast beyond 2024.

Table 6 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	175.1	88.7	131.7	102.3	55.1	81.8	0.0	634.7
Less Removals	17.0	6.9	9.6	7.8	4.1	5.9	0.0	51.3
Gross Investment Cost	**158.1**	**81.8**	**122.1**	**94.5**	**51.0**	**75.9**	**0.0**	**583.4**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**158.1**	**81.8**	**122.1**	**94.5**	**51.0**	**75.9**	**0.0**	**583.4**

[1] Includes overhead at current rates.

Table 7 presents test year costs for individual projects and presents the total cost for EOL ACSR, obsolete copper and deteriorated structure driven line refurbishment projects. The total cost includes costs incurred in previous years and forecasted beyond 2024, where applicable.

Table 7 - Detailed Project Costs

Project	Net Investment Costs ($ Millions)					20-24 Total ($M)	Project Total ($M)	In Service Date
	2020	2021	2022	2023	2024			
N21W/N22W, Sarnia Scott TS-Buchanan TS, Str. Refurb.	5.1	0.0	0.0	0.0	0.0	5.1	27.7	2019
D3A, Allanburg TS X AWS Steel CTS, Tx Line Refurb.	2.7	0.0	0.0	0.0	0.0	2.7	13.6	2020
B5/6C, BurlingtonTS X WestoverCTS, Tx Line Refurb.	5.5	0.0	0.0	0.0	0.0	5.5	22.9	2020
Line Refurbishment - D2L, Upper Notch JCT x Martin River JCT	3.0	0.0	0.0	0.0	0.0	3.0	28.3	2019
Tx Line Refurb: Placeholder, Expected EoL Line Discoveries	2.7	46.6	48.2	37.3	75.6	210.5	213.1	2025
Tx Line Refurb. B3/B4 | Horning Mountain JCT-Glanford JCT (Copper)	3.5	0.0	0.0	0.0	0.0	3.5	20.6	2020
Tx Line Refurb. A8K/A9K | A8K Str. 141 JCT-A8K Str. 277 JCT-Ramore JCT (Copper)	13.3	10.7	0.0	0.0	0.0	24.1	38.4	2021
Tx Line Refurb. A7L/R1LB & 57M1 Alexander B JCT-Lakehead TS & Nipigon JCT Copper	20.4	20.9	14.3	0.0	0.0	55.6	76.9	2022
Tx Line Refurb. K1/K2 | Kirkland Lake TS-Holloway Holt JCT (Copper)	3.2	0.0	0.0	0.0	0.0	3.2	6.5	2020

Tx Line Refurb. E1C | Ear Falls TS-Slate Falls DS (EoL) + Etruscan JCT-Crow River DS (Near EoL)	2.2	15.3	15.9	13.7	0.3	47.4	52.0	2024
Tx Line Refurb. H1L/H3L/H6LC/H8LC | Bloor Street JCT-Leaside 34 JCT (EoL)	1.6	10.4	5.5	0.0	0.0	17.5	17.6	2022
Tx Line Refurb. D2/3H & D4 & D6T, Hunta SS X Abitibi Canyon SS (EoL)	9.5	9.7	7.6	0.0	0.0	26.9	36.0	2022
Tx Line Refurb. D6 | Des Joachims JCT X Tee Lake JCT + Chalk River JCT X Petawawa JCT (Close EoL)	8.6	3.7	0.0	0.0	0.0	12.3	21.7	2021
Q2AH, ROSEDENE JCT X ST.ANNS JCT, Tx Line Refurb	0.4	4.8	2.9	0.0	0.0	8.1	8.1	2022
Net Investment Cost	**81.8**	**122.1**	**94.5**	**51.0**	**75.9**	**425.3**	**583.4**	

As shown in Figure 1, demographics for Hydro One overhead conductors demographics that have reached and exceeded EOL is increasing, thereby necessitating the replacement of those deteriorated EOL conductors. Line refurbishment investments are increasing over the test year period as compared to historical years which reflects the increase in circuit kilometres that are being replaced.

The following factors also influence the costs of Line Refurbishment Projects:

- The circuit voltage level, site accessibility, structure type (wood pole vs. steel structure);
- The length of conductor being replaced;
- Whether replacement of deteriorated shieldwire, insulators, or additional hardware is required; and
- Any structure or foundation work required.

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: The "Do Nothing" - Reactive Replacement involves waiting for deteriorated conductors to fail before replacing them on a reactive basis. This alternative has been rejected since a failed conductor will immediately lead to a circuit outage requiring emergency restoration. Replacement of conductors on an emergency basis will require constant reprioritization of planned work and lead to inefficient deployment of resources. Reactive conductor replacements would also prolong circuit outages and may therefore extend equipment and customer outages.

Alternative 2: Replacements based on Risk Mitigation Assessments is a preferred undertaking. It involves proactively replacing/refurbishing EOL ACSR conductors, obsolete copper conductors and deteriorated structures based on risk mitigation

assessments. The risk mitigation assessment allows Hydro One to replace High Risk assets in a way that mitigates safety and reliability risks while balancing the asset needs, resource availability and the cost impact to customers. This alternative has been selected as a preferred undertaking as it reduces the number of customer outages and allows taking advantage of planned customer outages to perform the necessary conductor replacements. Furthermore, with a planned outage, a customer can be temporarily connected to an alternative supply in order to avoid any unforeseen interruptions as a result of the outage. It further allows Hydro One to bundle all the necessary work in a particular geographic area in order to maximize the productivity of a deployed work crew. This is especially relevant in remote areas, where access is extremely difficult.

E. EXECUTION RISK AND MITIGATION

Risks to these projects include: outage constraints, resource constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges or regulatory approvals. A thorough risk assessment workshop is performed during the project planning phase where all known risks are identified and mitigation plan is developed. For example, to address outage constraints, Hydro One develops an outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize to a minimum the loss of supply to the customer. The plan might include switching a customer to an alternative supply, the construction of a temporary by-passing circuit or supply of portable generation that will maintain supply to the customer. Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages. Another example is the involvement of real estate from the project inception. It allows for the early identification of real estate issues, such as missing or inadequate land rights. Once the issue is identified, Hydro One tries to resolve it prior to execution of the project.

PROJECT SCHEDULE

TASK	START	FINISH
Section 92 Approval	May 13, 2026	Sept-2026
Receipt of Other Key Permits and Approvals	Jan-2026	Jun-2026
Voluntary Property Rights Acquisition	Aug-2025	Dec-2025
Detailed Engineering	Jan-2026	Apr-2026
Procurement	Feb-2026	Nov-2026
Construction	Oct-2026	Nov-2027
Commissioning	May-2027	Apr-2028
In Service	N/A	Apr-2028
Site Remediation Completion	N/A	Dec-2028

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DESCRIPTIONS OF THE PHYSICAL DESIGN

1.0 ROUTE DESCRIPTION

The Project is located between Petawawa, ON and Chalk River, ON. The Project will begin at existing structure 236 and rejoin the existing in-situ transmission line at existing structure 437. The total line length of the Project is approximately 21km and will utilize a 30.48m wide ROW.

A map showing the general route of the Project is provided as **Attachment 1** of **Exhibit B, Tab 2, Schedule 1**.

1.1 ROUTE DETAILS

1. The Project route starts at existing Structure 236, located near the CNL Chalk River Laboratories. The line will travel south for approximately 4 km, at which point it will then cross over Hwy 17.
2. The route will then continue south for approximately 14 km along an abandoned rail corridor located between Messer Trail and Hwy 17.
3. The Project route will then cross over the Petawawa River and travel in a south-west direction for approximately 3 km, at which point it will rejoin the existing D6 transmission line at Structure 437.

2.0 LINE DESCRIPTION

The proposed single circuit 115 kV transmission line will be comprised of 411.4 kcmil ACSR/TW “Simcoe” conductor, one 7#8 Equivalent 96 single-mode fiber optical ground wire, and one 7#8 Alumoweld overhead shieldwire. The line will be primarily supported on pole-type transmission structures. The Project has been designed using composite pole structures as the primary support type due to woodpecker presence in the area. In limited locations, steel structures will be installed where site-specific conditions warrant their use, including constructability, durability, or operational considerations such as the crossing of Highway 17, may include the use of lattice-type steel dead-end structures that can be expected to be utilized where higher structural capacity is necessary to accommodate heavy anchor applications.

The following provides and overview of the equipment and parameters expected to be used along the Project route:

The 115 kV transmission line will have the following attributes:

4. The line will have a continuous ampacity of 524A (summer ambient 35°C);
5. The line will have a long-term emergency ampacity of 686A (summer ambient 35°C);
6. Glass Type Insulators;
7. Stockbridge Dampers;
8. Sixteen Three Pole Type Deadend Structures;
9. Seven Three Pole Type Semi Strain Structures;
10. 48 H-Frame Pole Type Suspension Structures;
11. 40 Monopole Type Suspension Structures;
12. Nine Steel Structures including One Steel Lattice Type Heavy Anchor Dead End Structure
13. Pole type structures will be directly embedded; and
14. Steel structures will be supported on helical pile or micropile foundations.

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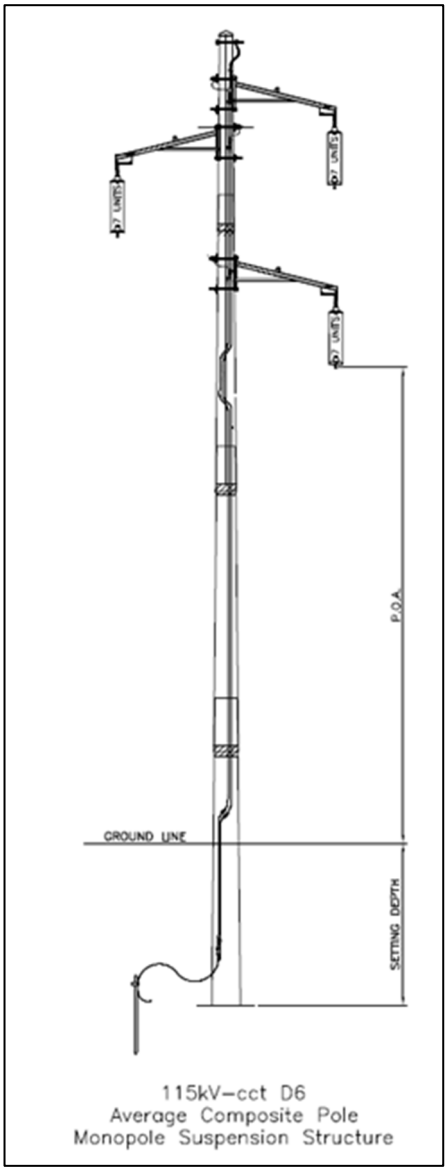


Figure 1: Average Monopole Type Suspension Structure

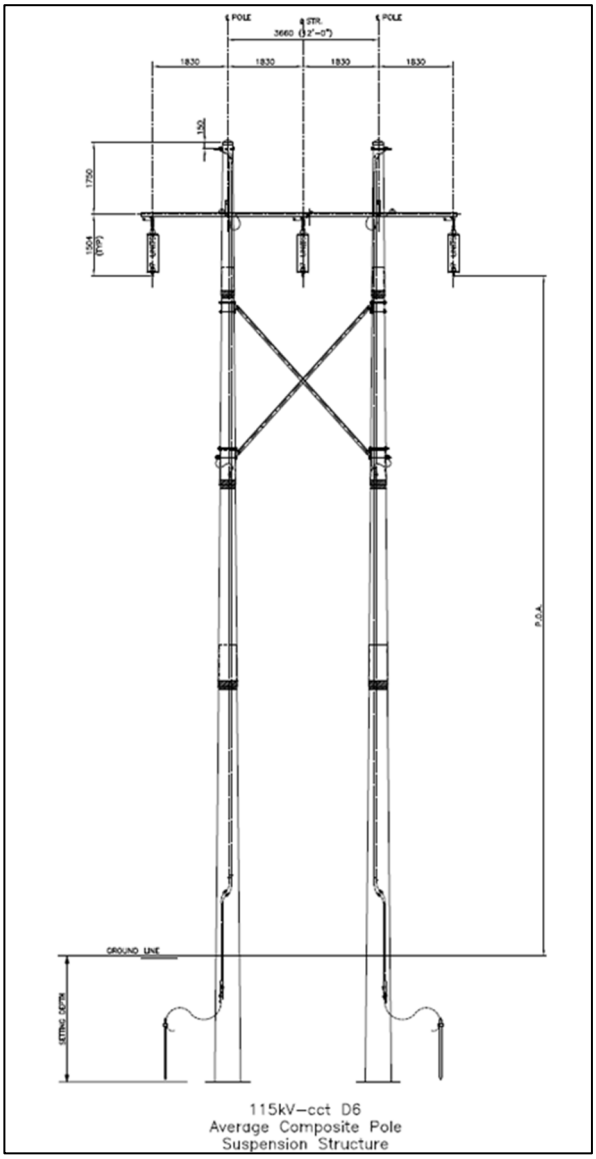


Figure 2: Average H-Frame Type Suspension

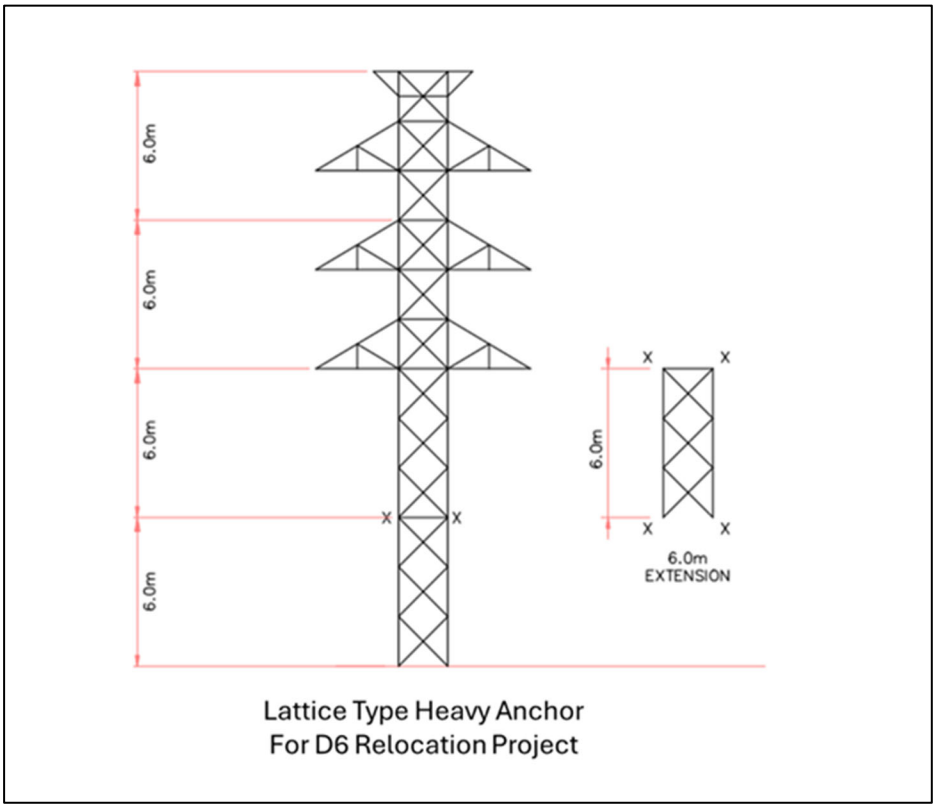


Figure 3: Lattice Type Heavy Anchor Structure

3.0 LINE REMOVAL

Once the D6 Relocation Project is complete, the existing transmission line assets between structures 236 and 437 are expected to be removed.

4.0 STATION WORK

No new equipment will be installed at the transmission stations for this Project. The station work will consist of equipment setting modifications, namely relay setting modifications, at Des Joachims TS (for circuit D6) and at Chenaux TS (for circuits X2Y and X6) to accommodate the new reduced transmission line length.

OPERATIONAL DETAILS

The Project involves the relocation of part of the existing transmission line facility located between Petawawa, ON and Chalk River, ON. The Project facility will remain part of the 115 kV transmission system and is required to continue to provide reliable supply for the Renfrew region. The Project circuit's route is situated between the terminal facilities of the Chalk River JCT and the Petawawa JCT, as described in the Application. Minor settings modifications made to Hydro One's protection, control and telecom facilities as part of the Project will protect the proposed transmission line by detecting faults and isolating faulted elements. The proposed facility will be operated by Hydro One's ISOC as directed by the IESO.

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LAND MATTERS

1.0 THE ROUTE

The majority of the D6 Relocation Project's proposed single circuit 115 kV transmission line will be sited within a corridor approximately 30m in width. The Project is primarily a greenfield route that traverses both private and publicly owned lands. The Project route will traverse approximately 18 km of federally owned lands while abutting Highway 17, while the remainder will be sited on privately owned lands. Hydro One has secured rights to all the privately held lands required for this Project.

2.0 DESCRIPTION OF LAND RIGHTS

The Project requires Hydro One to acquire land rights from 35 directly impacted properties, consisting of five privately held properties, 10 municipally held properties, four provincially held properties, and 16 federally held properties. All 16 federally held properties are within the boundaries of the Department of National Defence Petawawa Base. The majority of properties will require Hydro One to acquire easement interests, at the property owner's election. Hydro One has and continues to work with directly impacted property owners to finalize any necessary voluntary agreements. Hydro One currently holds 100% of the privately held land rights required along the route.

The relative area proportions specific to the properties affected requiring permanent land rights are as follows.

Table 1 - Summary of Property Types and Sized Required

Land Ownership Type	Area (Hectares)	Proportion of Route (%)
Private Lands	8	13.5%
Federal Lands	50	84.3%
Provincial Lands	0.7	1.2%
Municipal Lands	0.6	1.0%

3.0 MAPS OF THE PROJECT AREA

At **Exhibit B, Tab 2, Schedule 1, Attachment 1**, Hydro One has provided a copy of a map with the intention that it be used as the Application's *Notice Map* should the OEB determine that a hearing for this Application is required. **Attachment 2 of this Schedule** provides a more detailed route map that illustrates, as appropriate, properties along line route sections with lot and concession numbers of the land over, under, on or adjacent to which the line runs.

4.0 DESCRIPTION OF NEW LAND RIGHTS REQUIRED

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

- Easement rights on properties where the acquisition of new permanent lands rights are required;
- Temporary access and/or construction rights on federally, provincially, and municipally owned and private properties for access roads, temporary work headquarters, laydown areas, and material storage facilities (new land rights required).

Hydro One will document all required new land rights to construct, operate and maintain the transmission line in several agreements. On affected properties, the following land rights agreements are, or may be, required:

- Early Access Agreement;
- Option to Purchase a Limited Interest – Easement;
- Compensation and Incentive Agreement – Easement;
- Agreement for Temporary Rights; and
- Damage Claim Agreement/Waiver.

Where crossings of public roads and highways are contemplated and indicated in **Attachment 2** of this Schedule, Hydro One will rely on the land rights afforded by section 41 of the *Electricity Act, 1998, S. O. 1998, c. 15, Sched. A* (where applicable). Hydro One will notify and work with impacted road authorities, including municipalities and ministries, and obtain all required permits and/or agreements, including where agreements are

required for the placement of infrastructure per section 41(9) of the *Electricity Act, 1998*. All road crossings will be designed to meet or exceed Canadian Standards Association ("CSA") vertical clearance standards. Structures shall be located so that tower legs and guy wire anchor locations (above ground) are at least 15m from the edge of parallel or crossing roads.

Hydro One expects that permits/agreements for all required crossings will be acquired either prior to the start of construction or on an as needed basis.

Temporary rights, while not anticipated at this stage of Project development, may be required across private lands to facilitate construction of the Project. These rights will be negotiated and acquired as and when needed.

5.0 EARLY ACCESS TO LAND

Hydro One requires early access to the corridor to perform various activities/studies associated with the Project which include specific environmental studies, engineering and design studies, and property specific land valuations/studies. In order to facilitate the required access to the properties affected by the corridor in advance of Leave to Construct approval, Hydro One has achieved voluntary early access agreements with 100% of the private landowners.

6.0 LAND ACQUISITION PROCESS

Hydro One is seeking approval of voluntary property rights agreements with affected property owners based on its project-specific LACP[1]. The LACP were developed based on Hydro One's experience with land acquisition matters for new transmission projects, and act as a roadmap for affected property owners to understand Hydro One's acquisition process. Hydro One's central consideration is the need for affected property owners to have flexibility and choice while balancing Hydro One's desire to achieve timely acquisition

[1] Included in the Application at Attachment 1 to this Exhibit.

of land interests and its obligation to ensure that expenditures are fair and reasonable to Ontario transmission ratepayers.

Hydro One has been meeting with affected property owners since March 2025. The objective of these meetings has been to introduce affected property owners to Hydro One's voluntary land acquisition process. Independent site-specific property appraisals were completed and Hydro One prepared voluntary property settlement offers based on those appraisals and Hydro One's LACP. Hydro One began providing offers to affected property owners in August 2025. As of December 2025, five voluntary property settlement offers, pertaining to privately held lands, had been made, and those five offers were accepted. During property acquisition discussions Hydro One advised affected property owners 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.

All voluntary property rights agreements are in the form of an option agreement. Hydro One will exercise these options and conclude the land rights agreement transfer process once it has received the OEB's s.92 Leave to Construct approval of the Project. Once the option agreements are exercised, Hydro One will register easements on title for those properties.

All other applicable agreements (e.g. temporary rights agreements, etc.) will be utilized as part of the land acquisition process as required. A summary of all land negotiations to date, including their status, is summarized in Table 2 below. Further details on the properties and permits associated with the Project route are provided in **Attachment 3** of this Schedule.

Table 2 - Land Acquisition Status (As of April 22, 2026)

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 Lands	5	100%	100%	100%	100%	N/A	N/A
Federal Lands	16	N/A	N/A	N/A	N/A	N/A	N/A
Provincial Lands	4	N/A	N/A	N/A	N/A	N/A	N/A
Municipal Lands	10	N/A	N/A	N/A	N/A	N/A	N/A

7.0 LAND-RELATED FORMS

Attachments 4 through 8 of this Schedule contain copies of the land rights agreements that Hydro One has, and intends to, utilize to obtain the required new land rights for the Project and for related Project activities. Table 3 below sets out proceeding in which the forms of these agreements were previously approved. No substantive changes have been made to the forms of these agreements.

Table 3 - Forms of Agreement Remaining Unchanged

Form of Agreement	Attachment in this Schedule	Previous OEB Docket
Early Access Agreement	4	EB-2023-0198, Exhibit E, Tab 1, Schedule 1, Attachment 1
Option to Purchase a Limited Interest – Easement	5	EB-2023-0198, Exhibit E, Tab 1, Schedule 1, Attachment 4
Compensation and Incentive Agreement – Easement	6	EB-2023-0198, Exhibit E, Tab 1, Schedule 1, Attachment 5
Agreement for Temporary Rights	7	EB-2023-0198, Exhibit E, Tab 1, Schedule 1, Attachment 2
Damage Claim Agreement/Waiver	8	EB-2023-0198, Exhibit E, Tab 1, Schedule 1, Attachment 3

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HYDRO ONE
TRANSMISSION PROJECT

D6 TRANSMISSION LINE RELOCATION PROJECT

LAND ACQUISITION COMPENSATION PRINCIPLES

D6 TRANSMISSION LINE RELOCATION PROJECT

I. Introduction

Land Acquisition Compensation Principles

II. Acquisition Process

A. Project Need, Corridor Identification and Approvals

B. Introduction and Overview

C. Allowance Payment and Access to the Preferred Route

D. Preparation of Independent Property Appraisal Reports

E. Preparation of Hydro One Property Rights Acquisition Offers

F. Next Steps

III. Compensation Principles

A. General Principles

B. Principles Applicable to the Acquisition of Easement Interests

C. Principles Applicable to the Acquisition of Fee Simple Interests

D. Summary

Appendix A

Map of Preferred Route

I. INTRODUCTION

LAND ACQUISITION COMPENSATION PRINCIPLES

As part of the Class Environmental Assessment ("EA") process, Hydro One Networks Inc. ("Hydro One") has selected a preferred route for the D6 Transmission Line Relocation Project (the "Project"). This proposed project includes the relocation of approximately 25 kilometers of the line between the existing Chalk River Junction (JCT) in the Township of Laurentian Hills and the existing Petawawa JCT in the Town of Petawawa. 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 for required Project property rights with directly affected 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

A section of the existing115-kilovolt transmission line, known as Circuit D6, crosses an active area of the Department of National Defence's Garrison Petawawa military base. In order for Hydro One to minimize our impact to their military operations, it is required to relocate this portion of the transmission line.

For more information on the project please visit www.HydroOne.com/D6Relocation.

The Project is subject to the EA for Minor Transmission Facilities in accordance with 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 Fall 2025.

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 discussions with their Hydro One Real Estate Representative.

C. ALLOWANCE PAYMENT AND ACCESS TO THE PREFERRED ROUTE

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

(i) An immediate Allowance Payment of $5,000.00 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 Early Access Payment of $5,000.00 for allowing Hydro One's consultants access to and along the Project Corridor to conduct pre-construction activities. Pre-construction activities typically include 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 damages that may occur given Hydro One's and their consultants' presence for the Project during this access requirement (offered until shortly after Section 92 Approval).

Hydro One is scheduled to begin its pre-construction activities in the immediate future where possible. Acceptance of the Allowance Payment and Early 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

Hydro One and its independent 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 begin in Spring/Summer 2025.

E. PREPARATION OF HYDRO ONE PROPERTY RIGHTS ACQUISITION OFFERS

Hydro One will present each Property Owner with a formal voluntary land acquisition offer (the "Offer") based upon the information contained in the independent site-specific appraisal report. As part of the 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 and execute the necessary legal documentation.

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 $7,500.00, 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 until such time as Hydro One receives a decision from the Ontario Energy Board pursuant to Section 92 of the OEB Act. Should the Project receive Section 92 Approval, Hydro One will no longer require the Early Access agreements nor the Option agreements. Shortly after Section 92 Approval, the Offer from Hydro One will have the Early Access payment and the Option Payment removed.

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 general principles Hydro One will follow in respect to the voluntary acquisition 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 Valuation
Hydro One's Offers will be based upon site-specific appraisal reports prepared by external, independent appraisers who have received an Accredited Appraiser Canadian Institute (AACI) designation from the Appraisal Institute of Canada (AIC). This ensures that appraisals are conducted in accordance with professional standards established by the AIC. The appraiser will be directed to complete site-specific appraisals which will include a Property Owner interview and inspection of the property.

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 basis.

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 contracted 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 paid at the time the option agreement is executed (offered until shortly after Section 92 Approval) plus;

Acceptance of the Hydro One Offer
At the time Hydro One closes the transaction (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).

Property owners have reassurance that the Offer presented will not decrease if the market fluctuates downward after executing their voluntary agreements.

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 affected 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 a portion of the property required for the Project Corridor 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 contracted 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 executed (offered until shortly after Section 92 Approval) plus;

Acceptance of the Hydro One Offer
At the time Hydro One closes the transaction (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).

Property owners have reassurance that the Offer presented will not decrease if the market fluctuates downward after executing their voluntary agreements.

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 affected 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.

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. SUMMARY

Hydro One aims to enter into option agreements with Property Owners to acquire an easement/fee simple interest in the Project Corridor. 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 agreements.

At the time the option agreement is executed, Hydro One will pay Property Owners an incentive compensation amount of $10,000.00. 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 Approvals for the Project have been obtained.

APPENDIX A

Map of Preferred Route



FOR MORE PROJECT INFORMATION:

HydroOne.com/D6Relocation

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Updated: 2026-05-15
EB-2026-0112
Exhibit E-1-1
Attachment 2
Page 1 of 9

D6 Relocation Transmission Line - Section 92

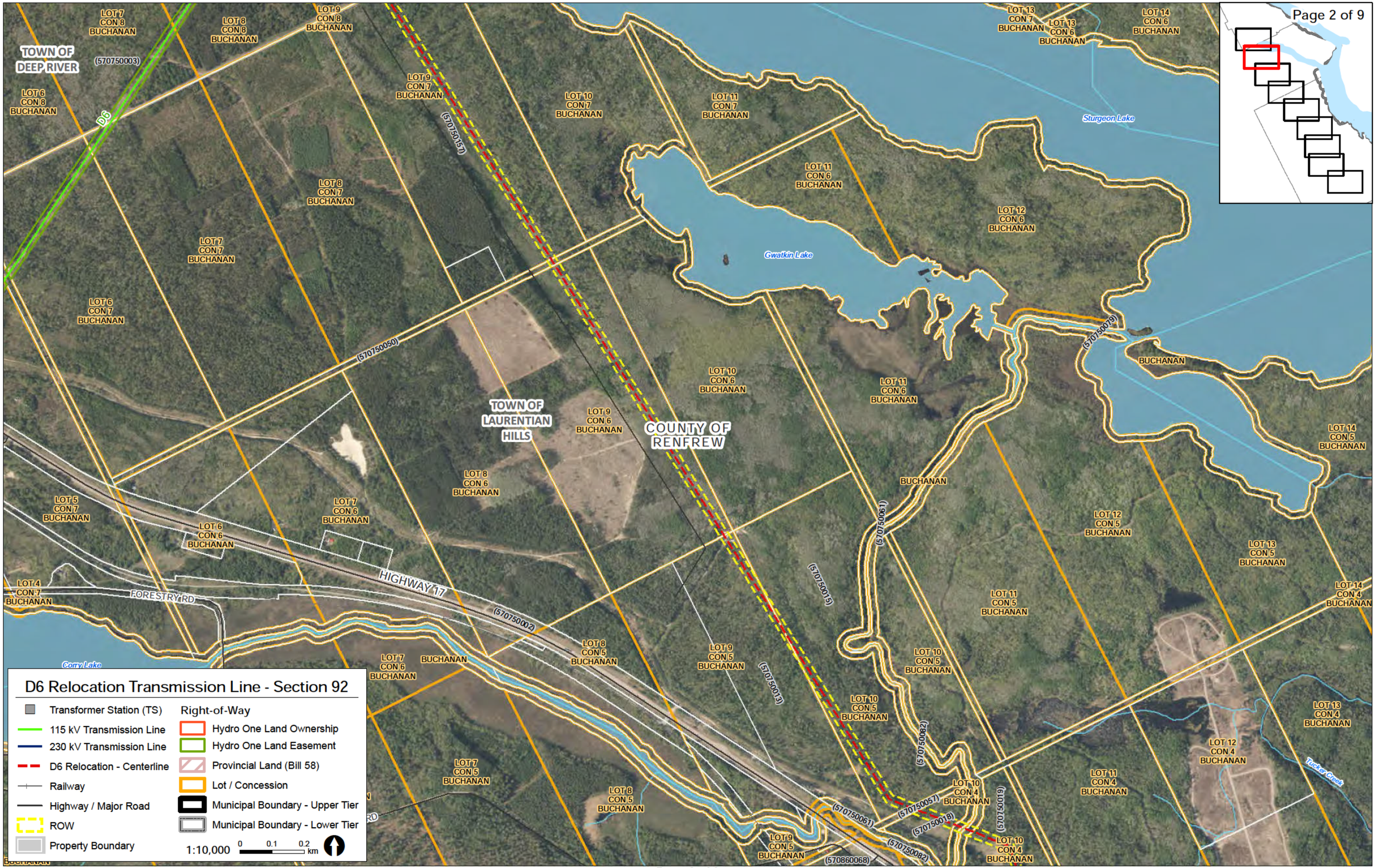
- Transformer Station (TS)
- 115 kV Transmission Line
- 230 kV Transmission Line
- D6 Relocation - Centerline
- Railway
- Highway / Major Road
- ROW
- Property Boundary

Right-of-Way

- Hydro One Land Ownership
- Hydro One Land Easement
- Provincial Land (Bill 58)
- Lot / Concession
- Municipal Boundary - Upper Tier
- Municipal Boundary - Lower Tier

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Produced By: Hydro One Networks Inc., GIS Services
Date: Feb 25, 2026
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D6 Relocation Transmission Line - Section 92

Transformer Station (TS)	Right-of-Way
115 kV Transmission Line	Hydro One Land Ownership
230 kV Transmission Line	Hydro One Land Easement
D6 Relocation - Centerline	Provincial Land (Bill 58)
Railway	Lot / Concession
Highway / Major Road	Municipal Boundary - Upper Tier
ROW	Municipal Boundary - Lower Tier
Property Boundary	

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Produced By: Hydro One Networks Inc., GIS Services
Date: Feb 25, 2026
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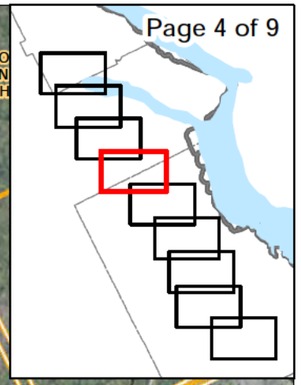
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LOT 8 CON 2 BUCHANAN
LOT 7 CON 2 BUCHANAN
LOT 14 CON 1 BUCHANAN
LOT 13 CON 1 BUCHANAN
LOT 12 CON 1 BUCHANAN
BUCHANAN
CLOUTHIER RD
LANDRY RD
HIGHWAY 17
TOWN OF LAURENTIAN HILLS
COUNTY OF RENFREW
DELUTHIER RD
MIDDLE RD
BASELINE RD
MESSER TRAIL
Tucker Creek
Young Creek
Landry Creek
Beaver Pond
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D6 Relocation Transmission Line - Section 92

Transformer Station (TS)	Right-of-Way
115 kV Transmission Line	Hydro One Land Ownership
230 kV Transmission Line	Hydro One Land Easement
D6 Relocation - Centerline	Provincial Land (Bill 58)
Railway	Lot / Concession
Highway / Major Road	Municipal Boundary - Upper Tier
ROW	Municipal Boundary - Lower Tier
Property Boundary	

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Produced By: Hydro One Networks Inc., GIS Services
Date: Feb 25, 2026
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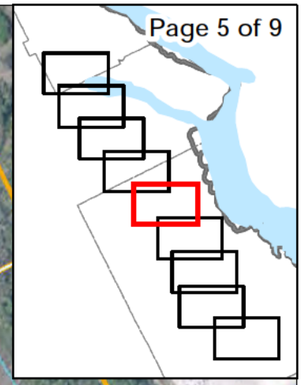
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(570860065)
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Landry Creek
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LOT 14 CON 1 BUCHANAN
LOT 8 CON 2 BUCHANAN
LOT 13 CON 1 BUCHANAN
LOT 40 RANGE A PETAWAWA
TOWN OF LAURENTIAN HILLS
(570750187)
LOT 12 CON 1 BUCHANAN
LOT 11 CON 1 BUCHANAN
LOT 7 CON 2 BUCHANAN
COUNTY OF RENFREW
HIGHWAY 17
PETAWAWA
Landry Creek
LOT 39 RANGE A PETAWAWA
LOT 10 CON 1 BUCHANAN
LOT 15 CON 16 PETAWAWA
LOT 9 CON 1 BUCHANAN
ORANGE RD
(570750002)
LOT 14 CON 16 PETAWAWA
LOT 38 RANGE A PETAWAWA
BUCHANAN
LOT 8 CON 1 BUCHANAN
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Tucker Creek
LOT 12 CON 16 PETAWAWA
TOWN OF PETAWAWA
Duke Lake
MIDDLE RD
Duke Creek
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LOT 15 CON 15 PETAWAWA
LOT 10 CON 16 PETAWAWA
LOT 14 CON 15 PETAWAWA
LOT 9 CON 16 PETAWAWA
LOT 13 CON 15 PETAWAWA
TUCKER LAKE RD
LOT 12 CON 15 PETAWAWA
LOT 11 CON 15 PETAWAWA
LOT 10 CON 15 PETAWAWA

D6 Relocation Transmission Line - Section 92

Transformer Station (TS)	Right-of-Way
115 kV Transmission Line	Hydro One Land Ownership
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Property Boundary	

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Date: Feb 25, 2026
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LOT 37 RANGE A PETAWAWA
LOT 36 LAKE RANGE PETAWAWA
LOT 36 RANGE A PETAWAWA
Bostwick Lake
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(570750188)
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LOT 10 CON 15 PETAWAWA
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BLACKBEAR RD
CLEMENT LAKE RD
LOT 35 RANGE A PETAWAWA
MIDDLE RD
Antler Creek
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LOT 33 LAKE RANGE PETAWAWA
TOWN OF PETAWAWA
COUNTY OF RENFREW
LOT 15 CON 14 PETAWAWA
LOT 14 CON 14 PETAWAWA
LOT 13 CON 14 PETAWAWA
Duke Creek
Antler Creek
LOT 32 LAKE RANGE PETAWAWA
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Antler Creek
Antler Lake
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TOTALIZE RD
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TUCKER LAKE RD
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PETAWAWA
MESSER TRAIL
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Duke Creek
Duke Creek
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Duke Creek
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BRINDLE RD
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CREST RD
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VERITABLE RD

D6 Relocation Transmission Line - Section 92

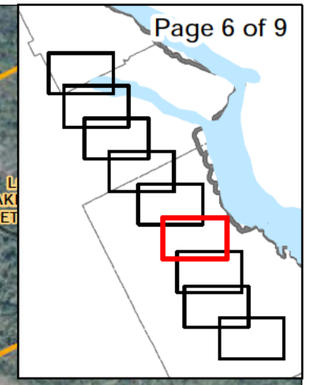
- Transformer Station (TS)
- 115 kV Transmission Line
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Right-of-Way

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Date: Feb 25, 2026
Map26-015_D6_Relocation_TxLine_Section92_Tile



LOT 15 CON 13 PETAWAWA
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(5108G0105)

Dike Creek
Range Creek
Range Lake

VERITABLE RD
BRINDLE RD
HIGHWAY 17
CREST RD
MESSER TRAIL
MENIN RD
KANDAHAR RD
CENTURION RD
WARRIOR DR
SAPPER WAY
FLANDERS ROW

TOWN OF PETAWAWA
COUNTY OF RENFREW
PETAWAWA

D6 Relocation Transmission Line - Section 92

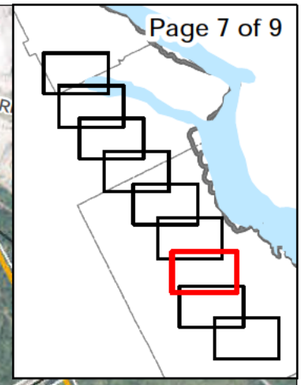
- Transformer Station (TS)
- 115 kV Transmission Line
- 230 kV Transmission Line
- D6 Relocation - Centerline
- Railway
- Highway / Major Road
- ROW
- Property Boundary

Right-of-Way

- Hydro One Land Ownership
- Hydro One Land Easement
- Provincial Land (Bill 58)
- Lot / Concession
- Municipal Boundary - Upper Tier
- Municipal Boundary - Lower Tier

1:10,000 0 0.1 0.2 km

Produced By: Hydro One Networks Inc., GIS Services
Date: Feb 25, 2026
Map26-015_D6_Relocation_TxLine_Section92_Tile



LOT 13 CON 11 PETAWAWA
LOT 14 CON 11 PETAWAWA
LOT 12 CON 11 PETAWAWA
LOT 11 CON 11 PETAWAWA
LOT 10 CON 11 PETAWAWA
LOT 11 CON 10 PETAWAWA
LOT 13 CON 10 PETAWAWA
LOT 14 CON 10 PETAWAWA
LOT 15 CON 10 PETAWAWA
LOT 16 CON 10 PETAWAWA
LOT 17 CON 10 PETAWAWA
LOT 18 CON 10 PETAWAWA
LOT 19 CON 10 PETAWAWA
LOT 18 CON 9 PETAWAWA
LOT 17 CON 9 PETAWAWA
LOT 16 CON 9 PETAWAWA
LOT 15 CON 9 PETAWAWA
LOT 14 CON 9 PETAWAWA
LOT 13 CON 9 PETAWAWA
LOT 12 CON 9 PETAWAWA
LOT 11 CON 9 PETAWAWA
LOT 10 CON 10 PETAWAWA
LOT 12 CON 10 PETAWAWA
LOT 10 CON 9 PETAWAWA
LOT 15 CON 8 PETAWAWA
LOT 14 CON 8 PETAWAWA
LOT 13 CON 8 PETAWAWA
LOT 12 CON 8 PETAWAWA
LOT 11 CON 8 PETAWAWA
LOT 17 CON 8 PETAWAWA
LOT 16 CON 8 PETAWAWA
LOT 18 CON 8 PETAWAWA
LOT 15 CON 7 PETAWAWA
LOT 16 CON 7 PETAWAWA
LOT 17 CON 7 PETAWAWA
LOT 18 CON 7 PETAWAWA
LOT 19 CON 8 PETAWAWA
PETAWAWA
TOWN OF PETAWAWA
COUNTY OF RENFREW
Brennan Lake
Jorgens Lake
Petawawa River
Jorgens Creek
(570860105)
(570750001)
(570940052)
(570940201)
(570940196)
SAPPER WAY
MONTGOMERY RD
CENTUR
MESSER TRAIL
HIGHWAY 17
COUNTY RD 55
PAQUETTE RD
PORTAGE RD

D6 Relocation Transmission Line - Section 92

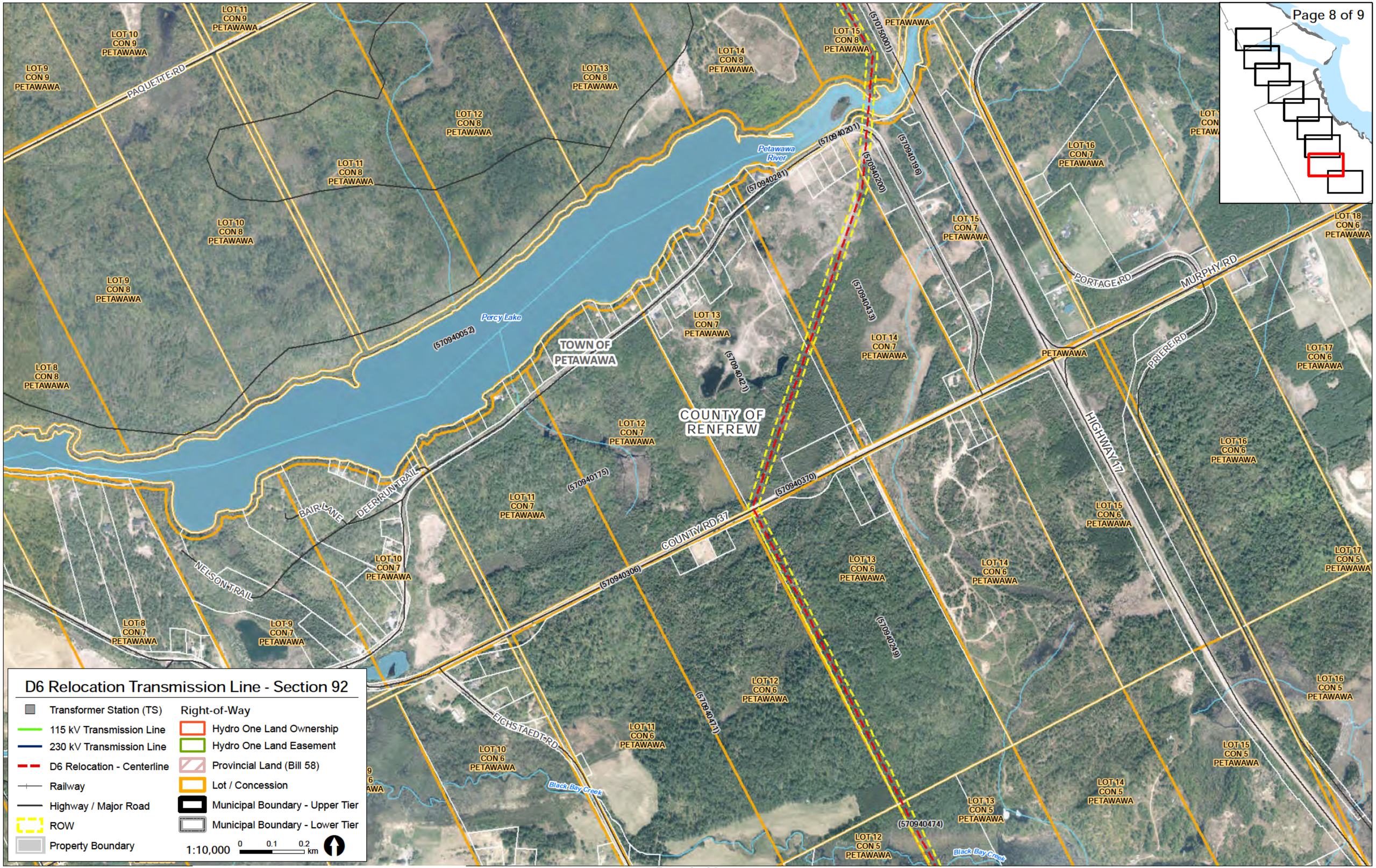
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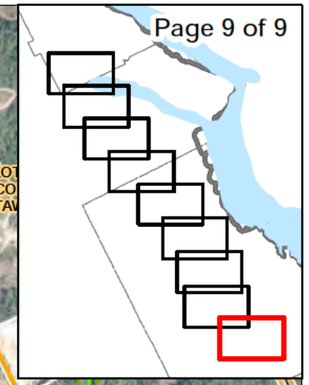


D6 Relocation Transmission Line - Section 92

Transformer Station (TS)	Right-of-Way
115 kV Transmission Line	Hydro One Land Ownership
230 kV Transmission Line	Hydro One Land Easement
D6 Relocation - Centerline	Provincial Land (Bill 58)
Railway	Lot / Concession
Highway / Major Road	Municipal Boundary - Upper Tier
ROW	Municipal Boundary - Lower Tier
Property Boundary	

1:10,000 0 0.1 0.2 km

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Map26-015_D6_Relocation_TxLine_Section92_Tile



D6 Relocation Transmission Line - Section 92

Transformer Station (TS)	Right-of-Way
115 kV Transmission Line	Hydro One Land Ownership
230 kV Transmission Line	Hydro One Land Easement
D6 Relocation - Centerline	Provincial Land (Bill 58)
Railway	Lot / Concession
Highway / Major Road	Municipal Boundary - Upper Tier
ROW	Municipal Boundary - Lower Tier
Property Boundary	

1:10,000 0 0.1 0.2 km

Produced By: Hydro One Networks Inc., GIS Services
Date: Feb 25, 2026
Map26-015_D6_Relocation_TxLine_Section92_Tile

	PIN (Property Identification Number)	LEGAL DESCRIPTION	TYPE OF PROPERTY	DOES HYDRO ONE REQUIRE NEW OR UPDATED PROPERTY RIGHTS	RIGHTS REQUIRED	Where Agreement is Outstanding - Summary of Negotiations to Date	OWNER(S) Filed Version on Public Record will be deleted
PW01	57094-0266 LT	LT 12 CON 5 PETAWAWA; W 1/2 LT 13 CON 5 PETAWAWA LYING S OF BLACK BAY RD EXCEPT PT 1, 49R2798 ; S/T PE2624 TOWN OF PETAWAWA	Private	Yes	Permanent Easement	Voluntary Settlement Executed	
PW02	57094-0226 LT	SECONDLY; PT LT 11 CON 5 PETAWAWA; PT LT 11 CON 6 PETAWAWA AS IN R33381; SECONDLY; PT LT 12 CON 5 PETAWAWA; PT W 1/2 LT 13 CON 5 PETAWAWA AS IN R51963; SECONDLY; PT E 1/2 LT 13 CON 5 PETAWAWA; PT LT 14 CON 5 PETAWAWA AS IN PE4820; SECONDLY; PT LT 6 CON 6 PETAWAWA AS IN R45019 & R77120; SECONDLY; PT LT 7 CON 6 PETAWAWA; PT LT 8 CON 6 PETAWAWA; PT LT 9 CON 6 PETAWAWA AS IN R45020; SECONDLY; PT LT 10 CON 6 PETAWAWA AS IN R44212; SECONDLY; RDAL BTN LT 10&11 PETAWAWA CON 6 LYING S OF A LINE DRAWN FROM THE MOST N ELY ANGLE OF R44212 TO THE MOST N WLY ANGLE OF R33381 & N OF A LINE DRAWN FROM THE MOST S ELY ANGLE OF R44212 TO THE MOST S WLY ANGLE OF R33381 BEING A TOWNSHIP RD KNOWN AS BLACK BAY RD ; S/T PE2591,PE2594, PE2624 TOWN OF PETAWAWA	Municipal	No	N/A	N/A	
PW03	57094-0474 LT	LT 12 CON 5 PETAWAWA; W 1/2 LT 13 CON 5 PETAWAWA LYING N OF BLACK BAY RD EXCEPT PT 1, 49R2796 PARTS 1 & 2 49R20248; TOWN OF PETAWAWA	Private	Yes	Permanent Easement	Voluntary Settlement Executed	
PW04	57094-0249 LT	LT 13 CON 6 PETAWAWA EXCEPT PT 1, 49R5470 & PT 5-10, 49R9333 ; TOWN OF PETAWAWA	Private	Yes	Permanent Easement	Voluntary Settlement Executed	
PW05	57094-0306 LT	CONSOLIDATION OF VARIOUS PROPERTIES FIRSTLY; PT LT 10, CON 6 PETAWAWA PT 14-17 & 19, 49R9332; SECONDLY; PT LT 10, CON 6 PETAWAWA PT 1, 49R5299 & PT 2, 49R3780; THIRDLY; PT LT 10, CON 6 PETAWAWA PT 1, 49R14237; FIRSTLY; PT LT 11, CON 6 PETAWAWA PTS 2-4, 6-9, 49R9332; FIRSTLY; PT LT 12, CON 6 PETAWAWA PT 12, 49R9333; FIRSTLY; PT LT 13, CON 6 PETAWAWA PT 5-10, 49R9333 & PT 2, 49R5470; FIRSTLY; PT LT 9,CON 7 PETAWAWA; PT LT 10, CON 7 PETAWAWA PT 1, 49R3125 & PT 10, 49R9332; SECONDLY; RDAL BTN CON 6 & 7 PETAWAWA LYING N OF A LINE DRAWN FROM THE MOST ELY ANGEL OF PT 23,49R9332 TO THE MOST WLY ANGLE OF PT 22, 49R9332 & W OF A LINE DRAWN FROM THE MOST N WLY ANGLE OF PT 9, R129282 TO THE MOST WLY ANGEL PT 4, R129282 KNOWN AS COUNTY RD 37 AKA MURPHY RD ; TOWN OF PETAWAWA	Municipal	No	N/A	N/A	
PW06	57094-0370 LT	PT LT 13 CON 7 PETAWAWA, PT 3, 49R9333 EXCEPT PT 1, 49R14609 ; TOWN OF PETAWAWA	Municipal	Yes	Permanent Easement	Discussions Ongoing	
PW07	57094-0421 LT	PART LOT 13, CONCESSION 7,PETAWAWA LYING SOUTH OF PORTAGE ROAD, SAVE AND EXCEPT PART 1, 49R1002, PART 1,49R14609, PARTS 1 & 2, 49R16287, PART 3, 49R9333, PART 1, 49R17255, PART 1 AND 2, 49R18490, & PART 3 49R18694, PARTS 1 AND 2 PLAN 49R18694; TOWN OF PETAWAWA	Private	Yes	Permanent Easement	Voluntary Settlement Executed	
PW08	57094-0433 LT	LOT 14 CONCESSION 7 PETAWAWA LYING SOUTH OF PORTAGE ROAD SAVE & EXCEPT PART 2 49R14609, PARTS 1 & 2 49R18920 & PARTS 1 TO 4, PL 49R19168; TOWN OF PETAWAWA	Private	Yes	Permanent Easement	Voluntary Settlement Executed	
PW10	57094-0200 LT	PT LT 15 CON 7 PETAWAWA PT 4, 49R430 ; TOWN OF PETAWAWA	Provincial	Yes	Permanent Easement	Discussions Ongoing	
PW11	57094-0281 LT	SECONDLY; PT LT 9 CON 7 PETAWAWA; PT LT 10 CON 7 PETAWAWA AS IN R123109; FIRSTLY; PT LT 11 CON 7 PETAWAWA; PT LT 12 CON 7 PETAWAWA PT 11, 49R7762; SECONDLY; PT LT 13 CON 7 PETAWAWA; PT LT 14 CON 7 PETAWAWA AS IN R49525 LYING S OF THE RDAL ALONG THE E/S OF THE PETAWAWA RIVER; FIRSTLY; PT LT 15 CON 7 PETAWAWA; PT RDAL ALONG THE E/S OF THE PETAWAWA RIVER PETAWAWA PT 1, R235097; RDAL BTN LT 10&11 PETAWAWA LYING E OF R123109 & W OF PT 11, 49R7762 ; TOWN OF PETAWAWA	Municipal	No	N/A	N/A	
PW12	57094-0196 LT	PT LT 15 CON 7 PETAWAWA; PT RDAL ALONG THE E/S OF THE PETAWAWA RIVER PETAWAWA PT 2, 49R430, PT 2, R235097 & PT 4 & 5, 49R293 AS PARTIALLY CLOSED BY R235097 ; TOWN OF PETAWAWA	Provincial	Yes	Permanent Easement	Discussions Ongoing	
PW13	57094-0201 LT	RDAL ALONG THE E/S OF THE PETAWAWA RIVER PETAWAWA LYING E OF PT 4, 49R12282 & W OF THE KING'S HWY 17 ; TOWN OF PETAWAWA	Municipal	No	N/A	N/A	
PW14	57094-0052 LT	PETAWAWA RIVER PETAWAWA LYING E OF THE NLY EXTENSION OF THE WLY LIMIT OF THE RDAL BTN THE TWP OF PETAWAWA & MCKAY & W OF THE NLY EXTENSION OF THE WLY LIMIT OF THE KING'S HWY 17 ; TOWN OF PETAWAWA	Municipal	Yes	Permanent Easement	Discussions Ongoing	

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PW16	57075-0001 R	PT LT 14 CON 8 PETAWAWA; PT LT 15 CON 8 PETAWAWA; PT LT 16 CON 8 PETAWAWA; PT LT 14 CON 9 PETAWAWA; PT LT 15 CON 9 PETAWAWA; PT LT 16 CON 9 PETAWAWA; PT LT 15 CON 10 PETAWAWA; PT LT 16 CON 10 PETAWAWA; PT LT 26 RANGE A PETAWAWA; PT LT 27 RANGE A PETAWAWA; PT RDAL BTN LT 15&16 PETAWAWA; PT RDAL BTN CON 8&9 PETAWAWA; PT RDAL BTN RANGE A & CON 10 PETAWAWA ; ROLPH BUCHN WYLIE MCKAY	Provincial	No	N/A	N/A	[redacted]
PW17	57086-0105 R	LT 15 CON 10 PETAWAWA ; TOWN OF PETAWAWA	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW18	57086-0106 R	LT 15 CON 11 PETAWAWA; LT 15 CON 12 PETAWAWA ; TOWN OF PETAWAWA	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW19	57086-0107 R	LT 27 RANGE A PETAWAWA; LT 28 RANGE A PETAWAWA; LT 29 RANGE A PETAWAWA ; TOWN OF PETAWAWA	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW20	57075-0190 LT	PT LTS 14 & 15, CON 13 & PT LTS 13 & 14, CON 14, PETAWAWA, PT 2, 49R19195; TOWN OF PETAWAWA	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW21	57075-0188 LT	PT LTS 12 & 13, CON 15 & PT LTS 12 & 13, CON 16, PETAWAWA, PT 3, 49R19193; TOWN OF PETAWAWA	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW22	57075-0187 LT	PT LTS 11 & 12, CON 1 & PT LT 11, CON 2, BUCHANAN, PT 2, 49R19194; TOWN OF LAURENTIAN HILLS	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW23	57086-0065 LT	LT 10 CON 2 BUCHANAN ; ROLPH BUCHN WYLIE MCKAY	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW24	57086-0068 LT	PT LT 10 CON 3 BUCHANAN; PT LT 9 CON 4 BUCHANAN; PT LT 10 CON 4 BUCHANAN AS IN BC837 & BC369, LYING W OF HWY NO. 17 EXCEPT BC31 ; ROLPH BUCHN WYLIE MCKAY	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW25	57086-0069 LT	PT LT 9 CON 4 BUCHANAN; PT LT 10 CON 4 BUCHANAN AS IN BC31 ; ROLPH BUCHN WYLIE MCKAY; SUBJECT TO AN EASEMENT FOR ENTRY AS IN RE227262	Municipal	Yes	Permanent Easement	Discussions Ongoing	
PW31	57075-0002 R	PT LT 26 RANGE A PETAWAWA; PT LT 27 RANGE A PETAWAWA; PT LT 28 RANGE A PETAWAWA; PT LT 29 RANGE A PETAWAWA; PT LT 15 CON 12 PETAWAWA; PT LT 14 CON 13 PETAWAWA; PT LT 15 CON 13 PETAWAWA; PT LT 13 CON 14 PETAWAWA; PT LT 14 CON 14 PETAWAWA; PT LT 13 CON 15 PETAWAWA; PT LT 12 CON 16 PETAWAWA; PT LT 13 CON 16 PETAWAWA; PT LT 11 CON 1 BUCHANAN; PT LT 12 CON 1 BUCHANAN; PT LT 11 CON 2 BUCHANAN; PT LT 10 CON 3 BUCHANAN; PT LT 11 CON 3 BUCHANAN; PT LT 9 CON 4 BUCHANAN; PT LT 10 CON 4 BUCHANAN; PT LT 8 CON 5 BUCHANAN; PT LT 9 CON 5 BUCHANAN; PT LT 6 CON 6 BUCHANAN; PT LT 7 CON 6 BUCHANAN; PT LT 8 CON 6 BUCHANAN; PT RDAL BTN LT 15 & RANGE A PETAWAWA; PT RDAL BTN LT 10&11 BUCHANAN; PT RDAL BTN CON 2&3 BUCHANAN; PT RDAL BTN CON 4&5 BUCHANAN; PT RDAL BTN TWP OF BUCHANAN & PETAWAWA BUCHANAN; PT SHORE RDAL ADJOINING THE NORTHERLY BANK OF CHALK RIVER BUCHANAN; PT SHORE RDAL ADJOINING THE SOUTHERLY BANK OF CHALK RIVER BUCHANAN; PT RDAL BTN LT 5&6 BUCHANAN; PT LAND UNDER THE WATER OF CHALK RIVER BUCHANAN; PT RDAL BTN CON 12&13 PETAWAWA; PT RDAL BTN CON 14&15 PETAWAWA ; IN THE TOWN OF PETAWAWA AND THE TOWN OF LAURENTIAN HILLS	Provincial	No	N/A	N/A	
PW32	57075-0019 LT	LT 10 CON 3 BUCHANAN; LT 10 CON 4 BUCHANAN LYING S OF THE SHORE RDAL ALONG THE S SHORE OF CHALK RIVER AND LYING E OF THE KING'S HWY # 17 ; S/T R246380 ROLPH BUCHN WYLIE MCKAY	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW33	57075-0079 LT	SHORE RDAL ADJOINING THE SOUTHERLY BANK OF CHALK RIVER BUCHANAN; SHORE RDAL ALONG S SHORE OF STURGEON LAKE BUCHANAN AKA CHALK LAKE; SHORE RDAL ON THE S SIDE OF THE OTTAWA RIVER PETAWAWA; SHORE RDAL ALONG THE OTTAWA RIVER AND/OR CHALK BAY BUCHANAN ALL LYING E OF THE KING'S HWY # 17 & N OF PT 2, 49R12179 ; S/T R246380 ROLPH BUCHN WYLIE MCKAY	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW34	57075-0082 LT	LAND UNDER THE WATER OF CHALK RIVER BUCHANAN LYING E OF THE KING'S HWY # 17 & W OF A LINE EXTENDING S OF THE MOST ELY EXT OF THE SHORE RDAL ALONG THE N SHORE OF CHALK RIVER ; S/T R246380 ROLPH BUCHN WYLIE MCKAY	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW35	57075-0061 LT	SHORE RDAL ADJOINING THE NORTHERLY BANK OF CHALK RIVER BUCHANAN LYING E OF THE KING'S HWY # 17 ; S/T R246380 ROLPH BUCHN WYLIE MCKAY	Municipal	No	N/A	N/A	
PW36	57075-0018 LT	LT 10 CON 4 BUCHANAN LYING N OF THE SHORE RDAL ALONG THE N SHORE OF CHALK RIVER ; S/T R246380 ROLPH BUCHN WYLIE MCKAY	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW37	57075-0057 LT	RDAL BTN CON 4&5 BUCHANAN LYING BTN SHORE RDAL ADJOINING THE NLY BANK OF CHALK RIVER ; S/T R246380 ROLPH BUCHN WYLIE MCKAY	Municipal	No	N/A	N/A	

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PW38	57075-0015 R	PT LT 10 CON 5 BUCHANAN ; ROLPH BUCHN WYLIE MCKAY	Federal	Yes	Permanent Easement	Discussions Ongoing	[redacted]
PW40	57075-0013 LT	LT 9 CON 5 BUCHANAN BEING E 1/2 LYING N OF KING'S HWY # 17 ; S/T R246380 ROLPH BUCHN WYLIE MCKAY	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW42	57075-0050 LT	RDAL BTN CON 6&7 BUCHANAN LYING E OF THE RDAL BTN LT 5 & 6 & W OF THE SHORE RDAL ALONG THE S SHORE OF STURGEON LAKE AKA CHALK LAKE ; S/T BC1048,R246380 ROLPH BUCHN WYLIE MCKAY	Municipal	No	N/A	N/A	
PW43	57075-0157 LT	PT LT 9 CON 7 BUCHANAN AS IN BC970 ; ROLPH BUCHN WYLIE MCKAY	Federal	Yes	Permanent Easement	Discussions Ongoing	
PW44	57075-0003 LT	LT 6 CON 8 BUCHANAN; LT 7 CON 8 BUCHANAN; LT 8 CON 8 BUCHANAN; LT 9 CON 8 BUCHANAN; LT 10 CON 8 BUCHANAN; LT 11 CON 8 BUCHANAN; LT 12 CON 8 BUCHANAN; LT 13 CON 8 BUCHANAN; LT 14 CON 8 BUCHANAN; LT 15 CON 8 BUCHANAN; LT 16 CON 8 BUCHANAN; PT LT 17 CON 7 BUCHANAN AS IN BC1853; LT 19 RANGE A BUCHANAN; LT 20 RANGE A BUCHANAN; LT 19 RANGE B BUCHANAN; LT 20 RANGE B BUCHANAN; PERCH LAKE BUCHANAN; STURGEON LAKE BUCHANAN AKA CHALK LAKE LYING N OF THE ELY EXT OF THE SLY LIMIT OF LT 10 CON 8; SHORE RDAL ALONG THE OTTAWA RIVER AND/OR CHALK BAY BUCHANAN LYING S OF THE ELY EXT OF THE SLY LIMIT OF THE RDAL BTN LT 20&21 RANGE B & N OF THE ELY EXT OF THE SLY LIMIT OF LT 19 RANGE B; RDAL BTN LT 10&11 BUCHANAN LYING S OF THE ELY EXT OF SLY LIMIT OF THE RDAL BTN CON 8 & 9 & N OF THE ELY EXT OF THE SLY LIMIT OF LT 10, CON 8; RDAL BTN LT 15&16 BUCHANAN LYING S OF THE ELY EXT OF THE SLY LIMIT OF THE RDAL BTN CON 8 & 9 & N OF THE ELY EXT OF THE SLY LIMIT OF LT 15 CON 8; RDAL BTN RANGE A&B BUCHANAN LYING S OF THE ELY EXT OF THE SLY LIMIT OF THE RDAL BTN CON 8 & 9 & N OF THE ELY EXT OF THE SLY LIMIT OF LT 19 RANGE A; SHORE RDAL ALONG S SHORE OF STURGEON LAKE BUCHANAN; SHORE RDAL ALONG N SHORE OF STURGEON LAKE BUCHANAN ALL LYING N OF THE SLY LIMIT OF LT 11&12 CON 8 ; TOWN OF DEEP RIVER	Federal	Yes	Permanent Easement	Discussions Ongoing	

THIS AGREEMENT made in duplicate the _____ day of _____ 2023.

BETWEEN:

(INSERT NAME)

(the **"Owner"**)
OF THE FIRST PART

AND:

HYDRO ONE NETWORKS INC.

(**"HONI"**)
OF THE SECOND PART

WHEREAS the Owner is the registered owner of lands legally described as ***(INSERT LEGAL DESCRIPTION),*** **being PIN** ***(INSERT PIN)*** **(the "Lands")**

AND WHEREAS the Owner is agreeable in allowing HONI to enter onto a portion of the Lands highlighted in yellow as shown on the sketch attached hereto as Schedule "A" (the "Strip"), in order to commence pre-construction activities in conjunction with the Waasigan Transmission Line Project (the "Project"), which shall include but are not limited to soil studies, environmental studies, engineering studies, property appraisals and surveys in, on or below the Strip subject to the terms and conditions contained herein (collectively the "Activities").

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of Two Dollars ($2.00) now paid by HONI to the Owner, and the respective covenants and agreements of the parties hereinafter contained and other valuable consideration, the receipt and sufficiency of which are hereby acknowledged by the parties hereto, the parties hereto agree as follows:

1. The Owner hereby grants to HONI and its respective officers, employees, workers, permittees, agents, surveyors, contractors and subcontractors, with or without vehicles, supplies, machinery, plant, material and equipment, (i) the right to commence the Activities on the Strip; and (ii) the right to enter upon and exit from, and to pass and repass at any and all times in, over, along, upon, across, and through the Strip and so much of the Lands as may be reasonably necessary.

2. The permission granted herein shall commence as of the date this Agreement (the "Commencement Date") and shall terminate three (3) years from the Commencement Date (the "Initial Term").

3. The Initial Term may be extended upon five (5) days prior notice from HONI to the Owner for an additional two (2) years on the same terms and conditions contained herein save for this right to extend (the "Extended Term").

4. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Lands shall be at the sole risk of HONI and the Owner shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the extent to which such loss, damage or injury is caused by the negligence or willful misconduct of the Owner.

5. Upon execution of this Agreement by all parties, HONI shall pay to the Owner the amount of **TWO THOUSAND FIVE HUNDRED Dollars ($2,500.00)** plus Harmonized Sales Tax ("HST") if applicable, which is compensation for the permission granted herein for the Initial Term.

6. In the event that HONI exercises its right to extend the Initial Term, HONI shall pay to the Owner the amount of ONE THOUSAND Dollars ($1,000.00), which is compensation for the permission granted herein for the Extended Term.

7. HONI shall repair any physical damage to the Lands resulting from the Activities and, shall restore the Lands to their original condition so far as possible and practicable to the satisfaction of the Owner, acting reasonably.

8. HONI agrees that it shall indemnify and save harmless the Owner from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Lands or of its activities on or in connection with the Lands arising out of the permission granted herein except to the extent any of such Costs arise out of the negligence or willful misconduct of the Owner.

9. This Agreement does not commit the Owner to enter into any further agreements with HONI in conjunction with the Project.

10. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

11. This Agreement may be executed in one or more counterparts and delivered by electronic means, each of which shall be deemed an original and all of which when, taken together, shall constitute one and the same Agreement.

IN WITNESS WHEREOF the Parties have hereunto set their respective hands and seals to this Agreement.

SIGNED, SEALED AND DELIVERED
In the presence of)
)
)
)
)
_____) _____ (seal)
Print Name of Witness ***Owner Name***

)
)
)
)
)
_____) _____ (seal)
Print Name of Witness ***Owner Name***

IF GRANTOR IS CORPORATION – USE THE FOLLOWING

OWNER NAME

Per: _____
Print Name:
Print Title:

Per: _____
Print Name:
Print Title:

We/I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

Per: _____
Print Name:
Title:

I have authority to bind the Corporation

SCHEDULE "A"

PROPERTY SKETCH

Conceptual sketch only.

OPTION AGREEMENT - EASEMENT

THIS OPTION AGREEMENT made as of the _____ day of _____, 20__ (the "**Agreement Date**").

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

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

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

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

OF THE SECOND PART

- and -

SPOUSE NAME

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

OF THE THIRD PART

RECITALS:

A. The Owner is the owner of the lands and premises described in Schedule "A" (the "**Lands**");

B. The Owner has agreed to grant to Hydro One for the consideration and on the terms and conditions set out herein and attached hereto as Schedule "B" (the "**Standard Terms and Conditions**") an option to purchase a right-of-way and easement in, on, over, under, across and through (the "**Easement**") that portion of the Lands described and shown on Schedule "A-1" attached hereto (the "**Easement Lands**"), the terms of which are more particularly set out in the Transfer and Grant of Easement (the "**Easement Agreement**") attached hereto as Schedule "C".

C. Hydro One has entered into an agreement with the Owner having a date the same as this Option Agreement (the "**Compensation and Incentive Agreement**") whereby Hydro One has offered to compensate the Owner for injurious affection damages in accordance with the terms and conditions contained therein.

NOW THEREFORE, the parties hereby agree as follows:

1. GRANT OF OPTION

In consideration of the sum of **XXXXX ($XXXXX)** of lawful money of Canada paid by Hydro One to the Owner, the receipt and sufficiency of which is hereby acknowledged by the Owner, (the **"Option Payment"**) the Owner hereby grants to Hydro One an irrevocable option (the "**Option**"), to purchase the Easement upon and subject to the terms and conditions set out herein, the Standard Terms and Conditions and the Schedules hereto.

2. PURCHASE PRICE

In accordance with the terms and conditions set out herein, the Standard Terms and Conditions and the Schedules hereto, Hydro One agrees to pay to or to the order of the Owner the amount of **XXXX Dollars ($ ●)** for the Easement Lands (the "**Purchase Price**") on the Closing Date.

IN WITNESS WHEREOF the parties hereto have duly executed this Option Agreement as of the Agreement Date.

WITNESS:

Name: «Real_Estate_Representative»

Address: 1800 Main Street East
Milton, ON L9T 7S3

OWNER:

l/s

Name: **«Owner_1_name_for_letters»**

l/s

Name: «Real_Estate_Representative»

Address: 1800 Main Street East
Milton, ON L9T 7S3

Name: **«Owner_2_name_for_letters»**

l/s

Name: «Real_Estate_Representative»

Address: 1800 Main Street East
Milton, ON L9T 7S3

Name: **«Owner_3_name_for_letters»**

WITNESS:

Name: Real Estate Representative

Address: 1800 Main Street East
Milton, ON L9T 7S3

The spouse of the Owner hereby consents to this Agreement

SPOUSE OF OWNER:

l/s

Name: **Property Owner Spouse Name**

HYDRO ONE NETWORKS INC.

Per: _____

Name:

Title:

I have authority to bind the Corporation

HYDRO ONE
HST 870865821RT0001

SCHEDULE "A"
LEGAL DESCRIPTION

«LEGAL_DESCRIPTION»

SCHEDULE "A-1"
EASEMENT LANDS

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

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

Screenshot of ortho map with tower placements here

SCHEDULE "B"
STANDARD TERMS AND CONDITIONS

1. EXERCISE OF OPTION

The Option shall be open for exercise at any time from the Agreement Date until the 2nd anniversary of the Agreement Date, as same may have been extended in accordance with the terms hereof, (the "**Option Term**"), by providing written notice to the Owner (the "**Exercise Notice**"), after which time, subject to Section 2, this Option Agreement shall be null and void and no longer binding upon either of the parties. If the Option is exercised within the Option Term, then this Option Agreement shall become a binding agreement for the purchase and sale of the Easement and this Option Agreement shall be completed on the terms set out herein.

2. EXTENSION OF OPTION TERM

At any time during the Option Term, Hydro One may, by written notice delivered to the Owner prior to the expiration of the Option Term, as same may have been extended, extend the Option Term with respect to the Lands for one (1) additional period of one (1) year, provided that upon such election, Hydro One pays to the Owner the amount of $XXXXX in consideration for the extension of the Option Term.

3. PURCHASE PRICE

(a) Hydro One shall pay the Purchase Price to or to the order of the Owner by way of a single payment by uncertified cheque or electronic funds transfer on the Closing Date (as hereinafter defined).

(b) The Owner acknowledges receipt of an appraisal report commissioned by Hydro One and, prepared by an external, independent appraiser with the Accredited Appraiser Canadian Institute ("AACI") designation, (the "**HONI Appraisal**").

(c) The parties acknowledge that the Purchase Price is based on a purchase price per acre as set out in Schedule "B" of the Compensation and Incentive Agreement and the actual area of the Easement Lands shall be confirmed by a survey to be prepared by Hydro One in accordance with section 9 herein, and in the event the surveyed area of the Easement Lands is greater than as provided for in Schedule "B" of the Compensation and Incentive Agreement, and Purchase Price shall be adjusted accordingly.

4. CLOSING

The transaction of purchase and sale contemplated by this Option Agreement shall, subject to resolution of any title issues identified by Hydro One, be completed on the date that is ninety (90) days after Hydro One delivers the Exercise Notice to the Owner or on such earlier date as Hydro One, through its solicitors, may elect (the **"Closing Date"**). If the Closing Date is a date on which the Land Registry Office (the "**Land Registry Office**") in which the Lands are registered is closed, the Closing Date shall be on the next following day when such Land Registry Office is open. In the event that there is a delay in the completion of the transaction beyond the Closing Date as established by Hydro One upon delivery of the Exercise Notice that arises through no fault of Hydro One, then Hydro One shall not be responsible for any resulting delay in the Closing Date.

5. ACKNOWLEDGEMENT AND DIRECTION

The Owner and, if applicable, the Spouse, acknowledges and agrees that execution of the Option Agreement shall constitute execution of the Acknowledgement and Direction attached as Schedule "D" to the Option Agreement (the "**Acknowledgement and Direction**") authorizing Hydro One and its solicitors to register the Option and subsequent Easement on title to the Lands. Hydro One covenants and agrees to hold the Acknowledgement and Direction in escrow until Hydro One has paid the Purchase Price at which time the executed Acknowledgement and Direction and Option shall be released from escrow and may be acted upon by Hydro One.

6. REGISTRATION OF EASEMENT

The Owner acknowledges and agrees that Hydro One will register the Easement on title to the Lands on the Closing Date pursuant hereto and the Acknowledgement and Direction. Hydro

One will provide notice to the Owner within a reasonable period of time after the Closing Date of the registration particulars of the Easement.

7. RIGHT TO TRANSFER

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

8. INSPECTION PERIOD AND EARLY ACCESS PERIOD

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

(b) The Owner agrees and consents to Hydro One, its respective officers, employees, agents, contractors, sub-contractors, surveyors, workers and permittees or any of them entering on, exiting and passing and repassing in, on, over, along, upon, across, through and under the Easement Lands and so much of the Lands as may be as reasonably necessary at all reasonable times from date Hydro One delivers the Exercise Notice to commence construction activities on the Easement Lands. Hydro One shall restore the Lands to their prior condition so far as reasonably possible in the event that the purchase transaction contemplated by this Option Agreement is not completed as contemplated herein.

9. SURVEY/REFERENCE PLAN

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

10. INCOME TAX ACT

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

11. HARMONIZED SALES TAX

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

12. NOTICE OF OPTION

Hydro One may, in its sole discretion and at its sole expense register this Option Agreement or notice thereof on title to the Lands.

13. NO OTHER RIGHTS

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

14. PRIOR ENCUMBRANCES

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

15. **TIME OF ESSENCE**

Time shall in all respects be of the essence hereof; provided, however, that the time for doing or completing any matter provided for herein may be extended or abridged by an agreement in writing between the parties or their respective counsel.

16. **NOTICES**

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

HYDRO ONE:

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

185 Clegg Road
Markham, Ontario L3G 1B7

Attention:
Fax: (905) 946-6242

with a copy to its solicitors,

Barriston LLP
90 Mulcaster Street
Barrie, ON L4M 4Y5

Attention: Jim McIntosh
Fax: 705-721-4025

OWNER:

«Owner_1_name_for_letters»
«Owner_2_name_for_letters»
«Owner_3_name_for_letters»
«STREET_NUM» «STREET_NAME1»
«MUNICIPALITY», «PROVINCE»
«POSTAL_CODE»

«SAP_Phone_Number»
«SAP_email_address»

with a copy to their solicitors,

Solicitors Name
Solicitors Address 1
Solicitors Address 2
Solicitors Address 3

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

17. **ASSIGNMENT OF OPTION BY HYDRO ONE**

Hydro One shall have the right to assign all or any part of its interest in this Option Agreement and any or all rights, privileges and benefits accruing to Hydro One hereunder without the consent of the Owner prior to or on the Closing Date. Upon and to the extent of such assignment, this Option Agreement shall thenceforth be construed as if originally made with such assignee or assignees instead of Hydro One and Hydro One shall, to the extent of such

assignment, thereupon be relieved of all liabilities and obligations whatsoever arising out of this Option Agreement.

18. **SURVIVAL OF REPRESENTATIONS**

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

19. **ENTIRE AGREEMENT**

The parties acknowledge that there are no covenants, representations, warranties, agreements or conditions, express or implied, collateral or otherwise, forming part of or in any way affecting or relating to this Option Agreement save as expressly set out in this Option Agreement and that this Option Agreement and all Schedules hereto constitute the entire agreement between the parties and may not be modified except as expressly agreed between the Owner and Hydro One in writing.

20. **SEVERABILITY**

Any provision or provisions of this Option Agreement is declared illegal or unenforceable, it or they shall be considered separate and severable from the Option Agreement and the remaining provisions shall remain in force and be binding upon the parties hereto as though the said provision or provisions had never been included.

21. **GOVERNING LAW**

This Option Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario.

22. **SUCCESSORS AND ASSIGNS**

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

23. **EXECUTION AND DELIVERY**

This Option Agreement may be executed in any number of counterparts, each of which is deemed to be an original and all of which taken together constitutes one agreement. To evidence the fact that it has executed this Option Agreement, a party may send a copy of its executed counterpart to all other parties by a delivery method set out in Section 16 herein (the "Transmission") and the signature transmitted by such Transmission is deemed to be its original signature for all purposes.

24. **PLANNING ACT**

This Option Agreement is subject to the express condition that it is to be effective only if the provisions of the *Planning Act, R.S.O. 1990, c. P.13* and amendments thereto are complied with.

25. **FURTHER ASSURANCES**

The Owner covenants and agrees to execute if necessary, at no further cost or condition to Hydro One such other instruments, plans and documents as may reasonably be required by Hydro One to effect the registration of the Easement or notice of this Option Agreement on title to the Lands.

26. **SPOUSAL CONSENT**

The Owner represents that, except to the extent such consent has been obtained, spousal consent to this transaction is not necessary and on closing will not be necessary under the provisions of the *Family Law Act*, R.S.O. 1990, c. F.3.

27. **AGE**

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

SCHEDULE "C"
TRANSFER AND GRANT OF EASEMENT

«Owner_1_name_for_letters» & «Owner_2_name_for_letters» & «Owner_3_name_for_letters» (the "**Transferor**") is the owner in fee simple and in possession of the certain lands legally described as «Legal_Description» (the "**Lands**").

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

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

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

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

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

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

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

(f) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for the Transferee, its employees, agents, contractors, subcontractors, workmen and permittees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or

convenient to the exercise and enjoyment of this easement, subject to compensation afterwards for any crop or other physical damage only to the Lands or permitted structures sustained by the Transferor caused by the exercise of this right of entry and passageway.

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

2. The Transferor agrees that:

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

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

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

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

(e) The Rights hereby granted:

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

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

3. Provided that the lands are used for agricultural purposes, the Transferee hereby releases and forever discharges the Transferor from and against any and all action, causes of action, costs,

claims, demands, expenses and liability for upon or by reason of any damage to the Works (collectively the "Claims") which may arise from, be sustained, suffered or incurred in consequence of the Transferor using the lands for agricultural purposes save and except for any Claims resulting from or arising out of the Transferor's negligence or willful misconduct.

4. The Transferor agrees that the Transferee may, at the Transferee's sole discretion, obtain at the Transferee's sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their respective rights, title and interests to the Transfer of Easement herein so as to place such Rights and easement in first priority on title to the Lands.

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

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

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

SCHEDULE "D"
ACKNOWLEDGEMENT AND DIRECTION

TO:	Hydro One Networks Inc. ("**Hydro One**") and its solicitors, Barriston LLP
AND TO:	Any and all designees of the above
RE:	Option Agreement dated _____, 20____, (the "Option Agreement) and the Transfer and Grant of Easement in substantially the form attached **[as Schedule "C" to the Option Agreement or hereto]** (the "Easement Agreement")

This will confirm that:

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

Dated _____, 20__.

WITNESS:	**OWNER:**
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_1_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_2_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	
	l/s
Name: «Real_Estate_Representative»	Name: **«Owner_3_name_for_letters»**
Address: 1800 Main Street East Milton, ON L9T 7S3	

WITNESS:

The spouse of the Owner hereby consents to this Acknowledgement and Direction

SPOUSE OF OWNER:

l/s

Name: Real Estate Representative
Address: 1800 Main Street East
Milton, ON L9T 7S3

Name: **Property Owner Spouse Name**

«OWNER_1_NAME_FOR_LETTERS»

Per: _____

Name:

Title:

We/I have authority to bind the Corporation

COMPENSATION AND INCENTIVE AGREEMENT - EASEMENT

THIS COMPENSATION AND INCENTIVE AGREEMENT made as of the _____day of _____ , 20___ (the "**Agreement Date**").

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

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

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

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

OF THE SECOND PART

- and -

SPOUSE NAME

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

OF THE THIRD PART

RECITALS:

A. The Owner is the owner of the lands and premises described in Schedule "A" attached hereto (the "**Lands**").

B. Hydro One desires to purchase a right of way and easement, in, on, over, under, across and through that portion of the Lands, as more particularly described in an Option Agreement between the parties hereto and having a date the same as this Compensation and Incentive Agreement (the "**Option Agreement**") (the "**Easement Lands**"), upon the terms and conditions set out in the Option Agreement (the "**Easement**").

C. Hydro One has offered to pay the Option Payment to the Owner upon execution of the Option Agreement and upon closing to purchase the Easement from the Owner for the Purchase Price.

D. Hydro One has offered, on the terms and conditions set out herein, to compensate the Owner for injurious affection damages, if applicable (the "**IA Compensation**") in respect of that portion of the Lands which are not part of the Easement Lands. Such injurious affection damages are calculated as shown on the calculation sheet attached hereto as Schedule "B" (the "**Calculation Sheet**").

E. To achieve a timely resolution of its land acquisition arrangements, Hydro One has also offered to pay certain incentives to the Owner on the terms and conditions set out in this Compensation and Incentive Agreement and as shown on the Calculation Sheet.

F. Any capitalized terms not defined in this Compensation and Incentive Agreement shall have the meaning ascribed to them in the Option Agreement.

NOW THEREFORE, the parties agree as follows:

1. VALUATION

(a) Hydro One has retained an external, independent AACI designated appraiser to determine the fair market value of the Easement Lands and any applicable amount of IA Compensation, if any, as of October 1st, 2021 and to prepare a report in respect thereof (the "**HONI Appraisal**"). The Owner acknowledges receiving a copy of the HONI Appraisal, and agrees to accept the amounts set out in the HONI Appraisal as a fair evaluation of the market value of the Owner's fee simple interest in the Easement Lands as of the date of the HONI Appraisal.

(b) In recognition of a dynamic real estate market and that the effective date of HONI's appraised values in the HONI Appraisal are only relevant for a limited period of time, Hydro One shall provide a market value top-up where the passage of time between the effective date of the HONI Appraisal and the date Hydro One receives project approval pursuant to section 92 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B. (the "Section 92 Approval") warrants such top-up (the "Top-Up").

Provided that the Owner and Hydro One have entered into an Option Agreement prior to Hydro One receiving the Section 92 Approval, the Owner shall be entitled to the Top-Up, if applicable. The amount of the Top-Up is the difference between the HONI Appraisal, and the market value as of the date of the Section 92 Approval (if such market value is greater than the amount in the HONI Appraisal), adjusted for time only (change in market conditions) and based on an independent land rate study considering this singular factor. The land rate study will be prepared by an independent third party appraiser with an Accredited Appraiser Canadian Institute designation from the Appraisal Institute of Canada.

The Top-Up amounts will be paid by Hydro One to the Owner by adding the applicable amounts to the Purchase Price, Premium Above Fair Market Value, and the IA Compensation, if applicable.

(c) The actual area of the Easement Lands will be confirmed by a survey to be prepared by Hydro One and in the event the surveyed area of the Easement Lands is greater than as provided for in the Calculation Sheet, the Purchase Price, Premium Above Fair Market Value, and the IA compensation, if applicable will be adjusted accordingly.

2. INCENTIVE PAYMENTS

(a) Upon execution of the Option Agreement and this Compensation and Incentive Agreement by all parties thereto, Hydro One shall pay to or to the order of the Owner the Option Payment in the amount of **XXXXX ($XXXXX)** as set out on the Calculation Sheet.

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

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

(d) On the Closing Date, Hydro One shall make a further incentive payment to or to the order of the Owner in the amount of **XXXXX ($XX)**, (the "**Woodlot Compensation**") as set out on the Calculation Sheet.

3. WAIVER

The Owner waives the right to be reimbursed by Hydro One for the reasonable costs the Owner incurs for a third party independent appraisal report and/or legal review of the HONI Appraisal, the Option Agreement and this Compensation and Incentive Agreement, up to the amount of

Seven Thousand Five Hundred Dollars ($7,500.00) and hereby accepts the Acceptance of the Hydro One Offer as defined in 2(b) above.

4. IA COMPENSATION

Hydro One agrees to pay to or to the order of the Owner on the Closing Date the IA Compensation, if applicable, in the amount of **XXXXX ($XX)** as set out on the Calculation Sheet.

5. CONVEYANCING

Hydro One agrees to reimburse the Owner for reasonably incurred legal fees, if any, associated with the review of applicable conveyancing documents.

6. TENANTS

The Owner agrees to indemnify and save harmless Hydro One from all actions, suits, costs, losses, charges, demands, claims and expenses for and in respect of any claims any person having a possessory interest in the Easement Lands.

7. NOTICES

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

HYDRO ONE:

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

185 Clegg Road
Markham, Ontario L3G 1B7

Attention:
Fax: (905) 946-6242

with a copy to its solicitors,

Barriston LLP
90 Mulcaster Street
Barrie, ON L4M 4Y5

Attention: Jim McIntosh
Fax: 705-721-4025

OWNER:

«Owner_1_name_for_letters» &
«Owner_2_name_for_letters» &
«Owner_3_name_for_letters»
«STREET_NUM» «STREET_NAME1»
«MUNICIPALITY», «PROVINCE»
«POSTAL_CODE»

«SAP_Phone_Number»
«SAP_email_address»

with a copy to their solicitors,

Solicitors Name
Solicitors Address 1
Solicitors Address 2
Solicitors Address 3

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

8. ASSIGNMENT OF AGREEMENT BY OWNER

The Owner shall not assign all or any part of its interest in this Compensation and Incentive Agreement or any of the rights, privileges and benefits accruing to the Owner hereunder without the consent of the Hydro One, which consent may not be unreasonably withheld or delayed.

Upon and to the extent of such assignment, this Compensation and Incentive Agreement shall thenceforth be construed as if originally made with such assignee or assignees instead of the Owner and the Owner shall, to the extent of such assignment, thereupon be relieved of all liabilities and obligations whatsoever arising out of this Compensation and Incentive Agreement.

The Owner and, if applicable, the Spouse, each covenant and agree that if they transfer, assign, charge, lease or otherwise dispose of all or any part of their interest in the Lands (collectively, a "**Transfer**") they will obtain an agreement from such Transferee assuming and agreeing to be bound by all of the terms of this Compensation and Incentive Agreement as if the Transferee had been an original signatory to this Compensation and Incentive Agreement.

9. NOTICE OF AGREEMENT

Hydro One may, in its sole discretion and at its sole expense register this Compensation and Incentive Agreement or notice thereof on title to the Lands.

10. NO MERGER

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

11. ENTIRE AGREEMENT

The parties hereto acknowledge that there are no covenants, representations, warranties, agreements or conditions, express or implied, collateral or otherwise, forming part of or in any way affecting or relating to this Compensation and Incentive Agreement save as expressly set out in this Compensation and Incentive Agreement and that this Compensation and Incentive Agreement and all Schedules hereto constitute the entire agreement between the parties and may not be modified except as expressly agreed between the parties in writing.

12. SEVERABILITY

Any provision or provisions of this Compensation and Incentive Agreement is declared illegal or unenforceable, it or they shall be considered separate and severable from this Compensation and Incentive Agreement and the remaining provisions shall remain in force and be binding upon the parties hereto as though the said provision or provisions had never been included.

13. GOVERNING LAW

This Compensation and Incentive Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario.

14. SPOUSAL CONSENT

The Owner represents that, except to the extent such consent has been obtained, spousal consent to this transaction is not necessary under the provision of the *Family Law Act*, R.S.O. 1990, c. F.3.

15. SUCCESSORS AND ASSIGNS

This Compensation and Incentive Agreement shall enure to the benefit of and be binding upon the parties hereto and their respective heirs, attorneys, guardians, estate trustees, executors, trustees, successors and permitted assigns.

16. EXECUTION AND DELIVERY

This Compensation and Incentive Agreement may be executed in any number of counterparts, each of which is deemed to be an original and all of which taken together constitutes one agreement. To evidence the fact that it has executed this Compensation and Incentive Agreement, a party may send a copy of its executed counterpart to all other parties by a delivery method set out in Section 7 herein (the "**Transmission**") and the signature transmitted by such Transmission is deemed to be its original signature for all purposes.

17. FURTHER ASSURANCES

The parties hereto agree to do, make and execute, if necessary, at no further cost or condition to the other except payment of reasonable out-of-pocket costs, such other instruments, plans, documents, acts, matters and things and take such further action as may reasonably be required

by the other party in order to effectively carry out the true intent of this Compensation and Incentive Agreement.

18. AGE

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

IN WITNESS WHEREOF the parties hereto have duly executed this Compensation and Incentive Agreement as of the Agreement Date.

WITNESS:

Name: «Real_Estate_Representative»

Address: 1800 Main Street East
Milton, ON L9T 7S3

OWNER:

l/s

Name: **«Owner_1_name_for_letters»**

l/s

Name: «Real_Estate_Representative»

Address: 1800 Main Street East
Milton, ON L9T 7S3

Name: **«Owner_2_name_for_letters»**

l/s

Name: «Real_Estate_Representative»

Address: 1800 Main Street East
Milton, ON L9T 7S3

Name: **«Owner_3_name_for_letters»**

WITNESS:

Name: «Real_Estate_Representative»

Address: 1800 Main Street East
Milton, ON L9T 7S3

The spouse of the Owner hereby consents to this Compensation and Incentive Agreement

SPOUSE OF OWNER:

l/s

Name: **Property Owner Spouse Name**

HYDRO ONE NETWORKS INC.

Per: _____

Name:

Title:

I have authority to bind the Corporation

HYDRO ONE
HST 870865821RT0001

SCHEDULE "A"

LANDS

«LEGAL_DESCRIPTION»

SCHEDULE “B”

CALCULATION SHEET

THIS AGREEMENT made in duplicate the _____ day of_____ 202X.

Between:

[INSERT SUBJECT PROPERTY LEGAL OWNER]

(hereinafter referred to as the "Grantor")

OF THE FIRST PART

--- and ---

HYDRO ONE NETWORKS INC.

(hereinafter referred to "HONI")

OF THE SECOND PART

WHEREAS the Grantor is the owner in fee simple and in possession of certain lands legally described as [INSERT SUBJECT PROPERTY LEGAL DESCRIPTION] being PIN: [INSERT SUBJCT PROPERTY PIN], collectively referred to as the "Lands".

WHEREAS HONI desires the right to enter onto and use a portion of the Lands in connection with the [INSERT PROJECT REQUIRING THE TEMPORARY SITE] (the "Project").

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the fee of XXXXX Dollars ($XXXX) plus harmonized sales tax ("HST") per month (the "Monthly Rent") to be paid by HONI to the Grantor, and the mutual covenants herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. The Grantor hereby grants, conveys and transfers to HONI in, over, along and upon that part of the Lands highlighted in red as shown in Schedule "A" attached hereto (the "Material Laydown Area"), the rights and privileges as follows:

(a) for the servants, agents, contractors and workmen of HONI at all times with all necessary vehicles and equipment to pass and repass over the Lands for the purpose of access to the Material Laydown Area;
(b) to store, use and maintain upon the Material Laydown Area, construction equipment and machinery as may be necessary for HONI's purposes;
(c) to place upon the Material Laydown Area, temporary trailers as may be necessary for HONI's purposes of a construction field office for the purposes of the Project; and
(d) to cut and remove all trees, brush and other obstructions made necessary by the exercise of the rights granted hereunder

2. The term of this Agreement and the permission granted herein shall be a term of XX (XX) months commencing on [INSERT DATE OF COMMENCEMENT] and ending [INSERT DATE OF EXPIRY] (the "Term"). HONI may, in its sole option, and upon 30 days' notice to the Grantor, extend the Term on a month to month basis for up to an additional XX (XX) months, under the same provisions and conditions contained in this Agreement, including the Monthly Rent.

3. Upon the expiry of the Term or any extension thereof, HONI shall remove and repair any physical damage to the Material Laydown Area and/or Lands resulting from HONI's use of the Material Laydown Area and the permission granted herein; and, shall restore the Material Laydown Area to its original condition so far as reasonably practicable.

4. The total amount of the Monthly Rent shall be paid in full by HONI at the commencement of the Term. For clarity, HONI shall pay the total amount of XXXX Dollars ($XXX) plus HST at the commencement of the Term.

5. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Material Laydown Area shall be at the sole risk of HONI and the Grantor shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the extent to which such loss, damage or injury is caused by the negligence or willful misconduct of the Grantor.

6. HONI agrees that it shall indemnify and save harmless the Grantor from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Material Storage Yard Area or of its activities on or in connection with the Material Storage Yard Area arising out of the permission granted herein except to the extent any of such Costs arise out of or are contributed to by the negligence or willful misconduct by the Grantor.

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

TO HONI:

Hydro One Networks Inc.
Real Estate Services
1800 Main Street East
Milton, Ontario L9T 753

Attention:
Tel:

TO GRANTOR:

XXXXXXX
XXXXXXX
XXXXXXX

Attention:
Tel:

8. Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5^{th}) business day following the date on which it was sent. Any notice sent by telegram, electronic facsimile or other similar means of prepaid recorded communication shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. "Business Day" shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

9. Any amendments, modifications or supplements to this Agreement or any part thereof shall not be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Agreement.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the day and year first above written.

[INSERT SUBJECT PROPERTY LEGAL OWNER]

_____
Grantor's HST Registration Number

_____
Name:
Title:

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

_____
Name:
Title:

I have authority to bind the Corporation

Page 3 of 4

Material Laydown Area

SCHEDULE “A”

*Sketch for reference only, not to scale.

Page 4 of 4

Damage Claim

THIS MEMORANDUM OF AGREEMENT dated the ____ day of _____, 20____

Between:

[INSERT NAME OF OWNER]

herein called the "**Claimant**"

- and-

Hydro One Networks Inc.

herein called the "**Hydro One**"

Witnesseth:

The Claimant agrees to accept: XXXXXXX ($XXX.XX) in full payment and satisfaction of all claims or demands for damages of whatsoever kind, nature or extent which may have been done to date by Hydro One during the construction, completion, operation or maintenance of the works of Hydro One constructed on [INSERT LEGAL DESCRIPTION] which property the Claimant is the legal owner and which damages may be approximately summarized and itemized as:

[INSERT DESCRIPTION OF DAMAGE]

Area

TOTAL $

.

Subject to Approval by Hydro One Networks Inc.

Witness

_____

Signature

_____

Signature

SYSTEM IMPACT ASSESSMENT

Please refer to **Attachment 1** of this Schedule for the Final SIA prepared by the IESO (SIA reference # CAA 2026-EX1314).

The Final SIA concludes that the Project is expected to have no material adverse impact on the reliability of the integrated power system and recommends that a Notification of Conditional Approval for Connection be issued.

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Expedited System Impact Assessment Report

Final Report - Public

CAA ID: 2026-EX1314
Project: Partial Relocation of 115 kV circuit D6
Connection Applicant: Hydro One Networks Inc.

April 24, 2026

ieso
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Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimer

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of conditional approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Conditional approval of the project is based on information provided to the IESO by the connection applicant and Hydro One at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by Hydro One at the request of the IESO. Furthermore, the conditional approval is subject to further consideration due to changes to this information, or to additional information that may become available after the conditional approval has been granted.

If the connection applicant has engaged a consultant to perform connection assessment studies, the connection applicant acknowledges that the IESO will be relying on such studies in conducting its assessment and that the IESO assumes no responsibility for the accuracy or completeness of such studies including, without limitation, any changes to IESO base case models made by the consultant. The IESO reserves the right to repeat any or all connection studies performed by the consultant if necessary to meet IESO requirements.

Conditional approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed project to the IESO-controlled grid. However, the conditional approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. This report does not in any way constitute an endorsement of the proposed connection for the purposes of obtaining a contract with the IESO for the procurement of supply, generation, demand response, demand management or ancillary services.

The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used. The IESO provides no comment, representation or opinion, express or implied, with respect to who should bear the cost of IESO requirements for connection in this report and disclaims any liability in connection therewith.

Project Description

Hydro One Networks Inc. (HONI, the "connection applicant" and "transmitter") is planning the following changes to the IESO-Controlled Grid (the "project"):

- The existing HONI 115 kV circuit D6 will be partially relocated between Structure #236 and Structure #437. This will reduce the length of the line section between Chalk River CTS (Q19) and Petawawa JCT (Q84) from 38.9 km to 30.7 km and therefore will reduce the overall D6 circuit length from 90.8 km to 82.7 km.
- The new relocated section (i.e. Chalk River CTS (Q19) - Petawawa JCT (Q84)) conductor will be 411.4 kcmil ACSR with 15/7 stranding (except for Segment 1 with 477.0 kcmil ACSR, 26/7 stranding). This will increase the section's continuous winter/summer rating to 646/524 Amps from the existing 384/284 Amps.
- The disconnect switch 19D684-1 JCT (Structure #250) will be removed

The proposed in-service date for the transmission line relocation is December 2027.

Notification of Conditional Approval

This assessment concludes that the proposed connection of the project is expected to have no material adverse impact on the reliability of the integrated power system, provided that all requirements in this report are implemented. Therefore, the assessment supports the release of the Notification of Conditional Approval for connection of the project.

IESO Requirements for Connection

General Requirements:

The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code (TSC) and reliability standards. Some of the general requirements that are applicable to this project are presented in detail in Appendix A: General Requirements of this report.

Appendix A: General Requirements

The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code and reliability standards. This section highlights some of the general requirements that are applicable to the project.

1. The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code and reliability standards. This section highlights some of the general requirements that are applicable to the project.
2. The connection applicant must notify the IESO at connection.assessments@ieso.ca as soon as they become aware of any changes to the project scope or data used in this assessment. The IESO will determine whether these changes require a re-assessment.
3. The connection applicant shall ensure that the project's equipment meet the voltage requirements specified in section 2.4.2 and section 2.4.3 of the Ontario Resource and Transmission Assessment Criteria (ORTAC).
4. According to Section 6.1.2 of the TSC, the connection applicant must ensure the project's transmission connection equipment is designed to withstand the fault levels in the area. According to Section 6.4.4 of the TSC, if any future system changes result in an increased fault level higher than the project's equipment capability, the connection applicant is required to replace that equipment with higher rated equipment capable of withstanding the increased fault level, up to the maximum fault level specified in Appendix 2 of the TSC. It is the connection applicant's responsibility to verify that all equipment and circuit breakers within the project are appropriately sized for the local fault levels.
5. The connection applicant must initiate the IESO's Market Registration process at least four months prior to the commencement of any project related outages. Once the IESO's Market Registration process has been successfully completed, the IESO will provide the connection applicant with a Registration Approval Notification (RAN) document, confirming that the project is fully authorized to connect to the IESO-controlled grid. For more details about this process, the connection applicant is encouraged to contact IESO's Market Registration at market.registration@ieso.ca
6. As per Market Manual 1.4: Connection Assessment and Approval, the connection applicant will be required to provide a status report of its proposed project with respect to its progress upon request of the IESO using the project status report form on the IESO website. Failure to comply with project status requirements listed in Market Manual 1.4: Connection Assessment and Approval will result in the project being withdrawn.

Disclaimer of Confidentiality

Appendices B to C, inclusive, contain confidential information of the IESO, the connection applicant, the transmitter and, potentially, other third parties, including information that, if disclosed, could reasonably be expected to pose a potential security threat to the *integrated power system*, the *IESO-administered markets*, or those of neighbouring jurisdictions.

Appendices B to C are intended only to be disclosed to and may only be used on a confidential basis by the connection applicant and transmitter. The connection applicant and transmitter may not, except as permitted by Section 5.3 of Chapter 3 of the Market Rules, disclose or use such information, other than for the purpose of carrying out its responsibilities as described in Section 6 of Chapter 4 of the Market Rules, the Transmission System Code and Market Manual 1.4.

Appendix B: Project Data (Confidential)

Appendix C: Technical Assessments (Confidential)

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/IESO

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CUSTOMER IMPACT ASSESSMENT

Please refer to **Attachment 1** of this Schedule for the Final CIA prepared by Hydro One.

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Customer Impact Assessment

Partial Transmission Line Relocation: 115 kV D6, Between Chalk River JCT and Petawawa JCT

CAA ID: 2026-13

Revision: Final

Date: 08-May-2026

Issued By: Transmission System Planning
Hydro One Networks Inc.

Prepared by:

Arjun Singh
Sorabh Devgun

Assistant Network Management Officer
Assistant Network Management Officer
Transmission System Planning

Reviewed by:

Quyen Diep
Ajay Garg

Senior Network Management Engineer
Senior Manager
Transmission System Planning

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Disclaimer

This Customer Impact Assessment ("**CIA**") is being performed in accordance with Hydro One Networks Inc.'s ("**Hydro One**") Customer Impact Assessment Procedure (Section 2.4) in Hydro One's Ontario Energy Board (OEB) approved Transmission Connection Procedures) and Section 6.41 of the OEB's Transmission System Code ("**Code**"). Hydro One performs a CIA where Hydro One has determined prior to conducting the CIA that one or more existing Hydro One transmission customers may be impacted by a proposed new or modified connection ("**Proposed Project**"). The CIA is intended to highlight impacts of the Proposed Project, if any, on existing Hydro One transmission customers early in the project development process and also provide an opportunity for existing Hydro One transmission customers that may be impacted by the Proposed Project to bring forward any concerns that they may have.

Please note that:

- the fault levels computed by Hydro One as part of this CIA are meant to assess current conditions and are not to be used by any person to size equipment or make other design decisions; and
- the estimate of the outage requirements identified in this CIA are subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements.

Hydro One may revise the result(s) of this CIA and issue CIA revision(s):

(i) where there are subsequent changes to the Proposed Project, the required transmission system modifications or the implementation plan that changes the impact of the Proposed Project on one or more existing connected transmission customers; and

(ii) to accommodate the IESO's requirements in respect of the Proposed Project identified in either the System Impact Assessment (SIA) or any revision(s) of the SIA for the Proposed Project.

Hydro One shall not be liable to anyone (including, without limitation, any existing transmission customer that Hydro One determined may be impacted by the Proposed Project) under any circumstances whatsoever for any: (i) direct damages resulting from or in any way related to the reliance on, acceptance or use of the CIA (and where applicable, any CIA revision(s)), in whole or in part, unless such liability arises under section 6.4 of the Code or the terms of a contract made between Hydro One and that person or entity with respect to the Proposed Project; and/or (ii) indirect or consequential damages, loss of profit or revenues, business interruption losses, loss of contract or loss of goodwill, special damages, punitive or exemplary damages, whether any of the said liability, loss or damages arises in contract, tort or otherwise.

Project Information

Project Name:	Partial Transmission Line Relocation: 115 kV D6, Between Chalk River JCT and Petawawa JCT				
CIA No:	2026-13	Revision:	Final	Date:	May, 8th, 2026
IESO CAA ID:	2026- EX1314				

Description of the Proposed Project

This project involves the partial relocation of the 115 kV Transmission circuit D6 between Chalk River Junction and Petawawa Junction initiated as part of the broader D6 Transmission Line Refurbishment program launched in June 2019. The project will relocate this section of the line outside Canadian Forces Base Petawawa territory along a new, shorter alignment of approximately 21 km that is compatible with Canadian Forces Base Petawawa operational requirements.

The proposed in-service date of the Proposed Project is Q4 2027.

The IESO has carried out a System Impact Assessment 2026- EX1314 for the Proposed Project dated April 22nd, 2026 ("SIA") and concluded that there is no adverse impact on the reliability of the integrated power system because of the Proposed Project provided that requirements identified in the SIA are met, including, without limitation.

Transmission circuit D6 is to be relocated between structure #236 and structure #437. The Chalk River (Q19) X Petawawa JCT (Q84) section of line will be reduced from 38.9 km to 30.7 km.

Please note that the single line diagram in Appendix-2 is confidential information and is provided in the confidential section of the SIA report.

Existing Connected Transmission Customers

Hydro One determined prior to conducting this CIA that the following existing Hydro One transmission customers may be impacted by the Proposed Project (collectively, the "**Existing Customers**"):

Customer Name
Atomic Energy of Canada Limited
Hydro One Distribution Inc.

Project Impact

The Proposed Project involves:

Relocation of 115kV D6 line between Chalk River JCT (Q19) and Petawawa JCT (Q84) (earlier 38.9km and new ~30.7 km after relocation). There is no material change in voltages, power flows, or short circuit levels because of the Proposed Project. The values of the short circuit levels for the connection points of the Existing Customers are provided in Appendix 1.

No neighboring-customer reliability degradation is anticipated. No significant reliability issue is expected to arise from the proposed D6 relocation Project.

Outages will be managed with the input of the Existing Customers to minimize impact.

Conclusion

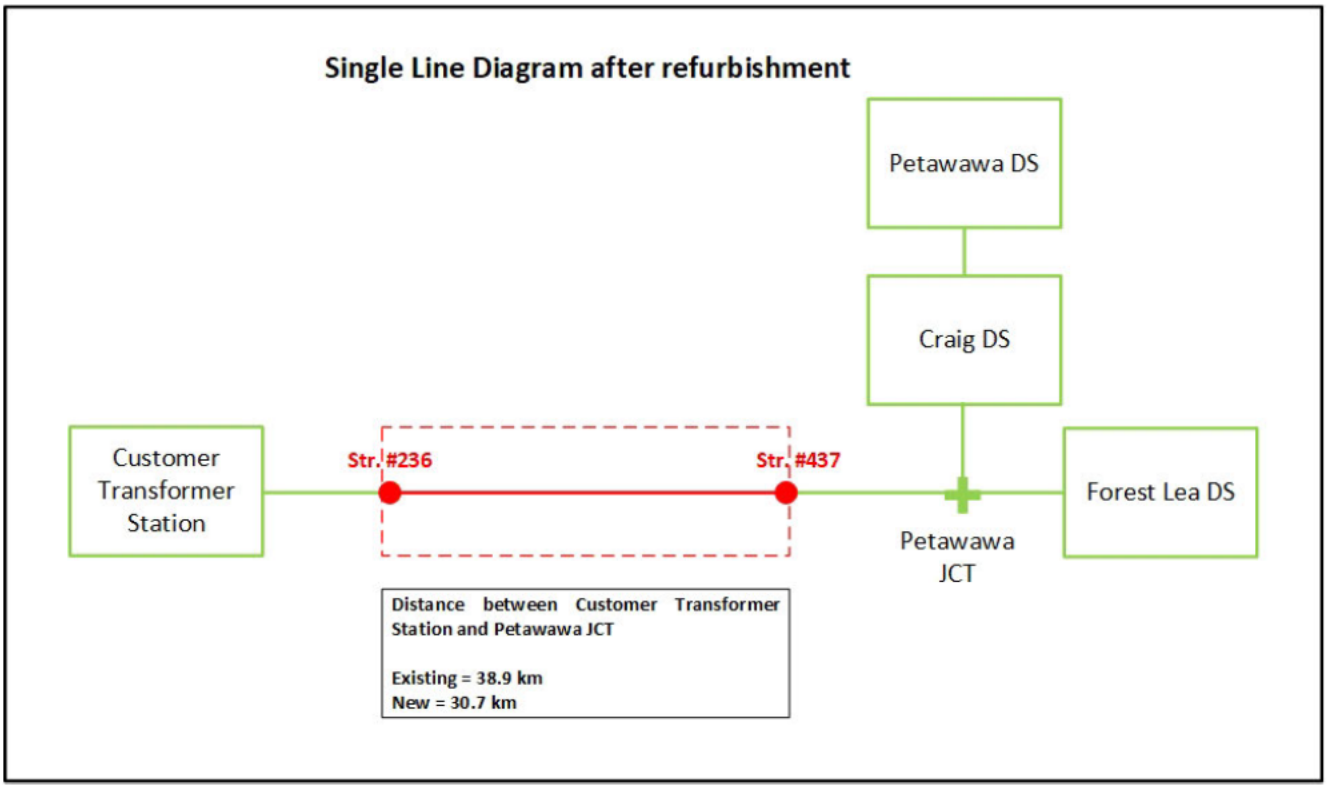
There is no material impact expected on the connection of the Existing Customers to the transmission system due to the Proposed Project. In addition, the Proposed Project, as per the SIA, will not have any adverse impact on the IESO-controlled grid when all the recommendations in the SIA, if any, are implemented.

Appendix 1 - Short Circuit Levels After D6 Project completion

Station	kV	3ϕSym (kA)	3ϕASym (kA)	1ϕSym (kA)	1ϕASym (kA)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Note that the SC levels are calculated assuming this project is in-serviced.

Appendix 2 – Diagrams (as applicable)



REGIONAL AND BULK PLANNING

The most recent regional and bulk planning reports in support of this Project are provided in Attachments 1 and 2 to this Exhibit, as noted below:

Attachment 1: Renfrew Region Integrated Regional Resource Plan ("IRRP") - December 2022.

Attachment 2: Renfrew Regional Infrastructure Plan ("RIP") - July 2023.

As it pertains to the D6 circuit, the December 2022 IRRP focused on the area's capacity issues and monitoring actions and did not include any new analysis specific to the refurbishment scope of the D6 circuit. The July 2023 RIP identified the need for refurbishment of the 115 kV D6 transmission line based on Hydro One's asset condition assessment and is required to address the deteriorated state of the line. The conclusions of these reports are consistent with the IESO's evidence in support of need, as provided at **Exhibit B, Tab 3, Schedule 1, Attachment 1**.

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Renfrew Region Integrated Regional Resource Plan

December 22, 2022

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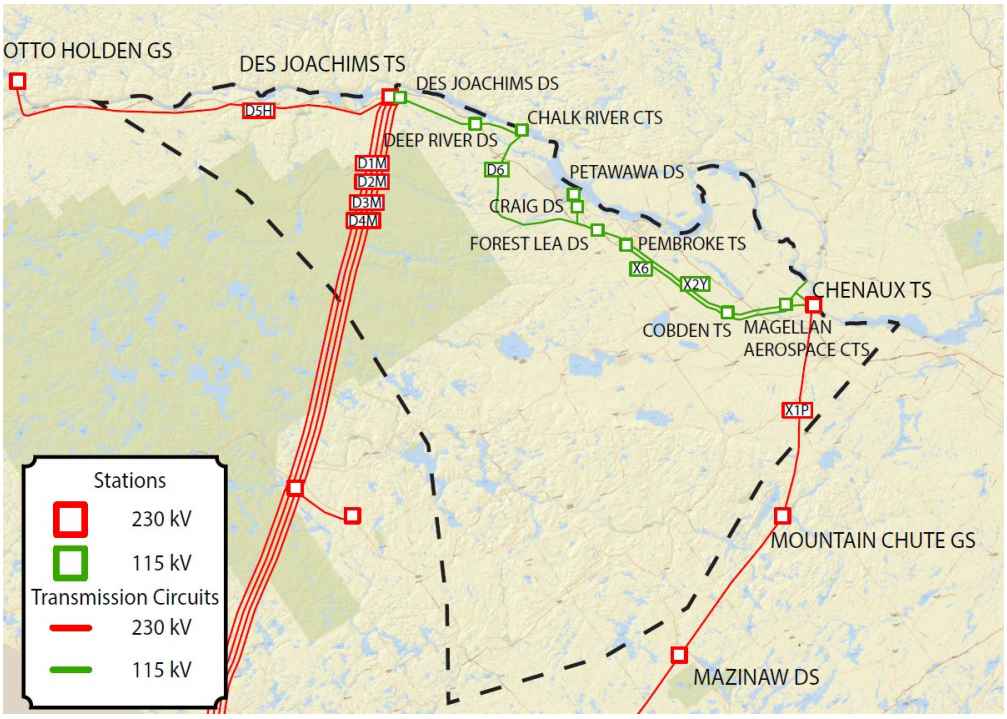
List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
DG	Distributed Generation
DS	Distribution Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
MVA	Megavolt ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station

1. Introduction

This Integrated Regional Resource Plan (IRRP) for the Renfrew region addresses the regional electricity needs over the study period, i.e., from 2021 to 2042. The Renfrew region is located in Eastern Ontario with the majority of the population residing along the Ottawa river. It is bounded by two hydro generating stations, Des Joachims in the west and Chenaux in the east. The Renfrew region, shown in Figure 1, includes five Indigenous and Metis communities and 18 municipalities with a total population of approximately 100,000 people.

Figure 1 | Renfrew Region Map



The purpose of this IRRP is to document the findings and actions required to address the transmission system issues in the region. The IRRP is one part of the overall planning process and this report is the final product of this stage. The regional electricity planning process was formalized by the Ontario Energy Board (OEB) in 2013, and it requires transmitters, distributers, and the Independent Electricity System Operator (IESO) to carry out regional planning activities for the 21 electricity planning regions across Ontario at least once every five years. This is the first time that issues have been identified in Renfrew that require further regional coordination and, as a result, this is the first IRRP for the Renfrew region.

The region has historically had low growth, however, the electricity demand is slowly reaching the capacity of the transmission system. Specifically, there have been station capacity issues identified in the Pembroke, Petawawa, and Laurentian Valley areas. The scope of this IRRP is centered around addressing these issues and the Technical Working Group has taken this opportunity to engage on a broader scale with municipalities, large electricity customers, and other relevant stakeholders in order to understand some of the electricity trends that are affecting the region.

Through public webinars, stakeholder feedback, and individual engagements a number of trends impacting the region's future electricity demand have been identified. Several communities are seeing larger migrations from urban centers and are preparing for residential developments. The majority of existing residential areas do not have air conditioners and also utilize gas heating both of which when installed and converted will contribute to peak energy consumption in the summer and winter, respectively. Lastly, the impact of electrification, which is being felt across the province, could further constrain the transmission system that has historically seen flat growth.

This IRRP report summarizes upcoming power system capacity, reliability, and end-of-life asset replacement issues and recommends specific investments to address the most imminent issues. This IRRP also recommends near-term activities to manage longer-term requirements. The next planning cycle is scheduled to be initiated in 2026. Annual monitoring of potential issues will provide additional input on when the next regional planning cycle should be initiated.

The report is organized as follows:

- A summary of the recommended plan for the Renfrew region is provided in Section 2;
- The process and methodology used to develop the plan is discussed in Section 3;
- A background of the Renfrew region is presented in Section 4;
- The development and methodology of creating the 20-year long-term forecast is presented in Section 5;
- The electricity issues for the Renfrew region are presented in Section 6;
- Options, alternatives, and recommendations to address the issues are presented in Section 7;
- A summary of engagement activities to date, and moving forward, is provided in Section 8;
- The conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Renfrew region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC).

This IRRP identifies three planning horizons: near-term (year 1 to 5), medium-term (year 6 to 10), and long-term (year 11 to 20) from the base year (2020). These planning horizons reflect the inverse relationship between the length of time and demand certainty (in that the longer the outlook, the less certain it is), lead time for electricity resource development, and planning commitment required. This IRRP identifies and recommends specific projects for implementation in the near-term. This is necessary to ensure that they are in-service in time to address the area's more urgent needs, respecting the lead-time for development of the recommended projects or actions.

This IRRP also identifies possible long-term electricity needs, some of which may advance to the near- or medium-term for a high growth scenario. However, as these needs are forecast to arise in the future, it is not necessary, nor would it be prudent given forecast uncertainty and the potential for technological change, to commit specific projects at this time. Instead, near-term actions are identified to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle so that their results can inform further discussion at that time or so the Technical Working Group can respond in a timely manner, if a high growth scenario were to materialize.

2.1 Near- to Medium- Term Plan

Recommended Actions

1. **Build new station at Pembroke, finalize scope during Regional Infrastructure Plan (RIP) period**

The existing Pembroke Transformer Station (TS) supplies the City of Pembroke. Two Local Distribution Companies (LDC) supply customers from Pembroke TS, Hydro One Distribution and Ottawa River Power Corporation (ORPC), as an embedded customer to Hydro One Distribution. The station has an existing 1 MW station capacity issue that is forecast to increase to 14 MW, in the summer, over the study period. A new station, targeting an in-service date of 2027 has been identified as the preferred option to address the need. Both a High Voltage Distribution Station (HVDS) and a standard dual-element spot network (DESN) transformer station were considered as options.

Both would meet the long-term forecast and each have their benefits and risks. A standard DESN station is preferred from a reliability perspective and would better prepare the area to accommodate long-term needs, but comes at an increased cost. The Technical Working Group recommends that further analysis be conducted during the RIP stage of regional planning to refine costs and benefits and confirm the additional cost of a DESN station is warranted.

2. **Perform a 2 MW load transfer from Forest Lea Distribution Station (DS) to Craig DS**

Forest Lea DS is located in Laurentian Valley and currently has a 1 MW station capacity issue. There is an existing tie-point on the distribution system between Forest Lea DS and Craig DS that can be used for load transfer. The Technical Working Group recommends this tie-point be utilized to transfer 2 MW of load from Forest Lea DS to Craig DS. This action is estimated to take 1-2 years to complete, targeting an in-service date of 2025. Further, if additional capacity is needed in the future the Technical Working Group recommends installing transformer fan cooling and Supervisory Control and Data Acquisition (SCADA) monitoring at Forest Lea DS to increase the station limit by an additional 4 MW.

3. **Build a new HVDS at Petawawa DS**

Petawawa DS supplies both the town of Petawawa and a large institutional customer, with the large customer representing the majority of the load supplied from the station. Due to upcoming development on the customer's site and forecast growth for the town of Petawawa, the station capacity is forecasted to be exceeded in 2029. Further, through the engagement process a growth scenario was developed to reflect significant load increase due to fuel switching in the long-term. The Technical Working Group recommends to build a new HVDS near Petawawa to meet the forecast demand growth. The expected in service year for the new station is 2027.

2.2 Long- Term Plan

Recommended Actions

1. **Monitor the load on the Des Joachims sub-system**

Through discussions with the stakeholders in the region, the Technical Working Group developed two growth scenarios, primarily driven by two separate large scale projects. If both projects materialize the Des Joachims sub-system will require upgrades. If only one project materializes, a capacitor installed at the end of the line will improve the limit of the system sufficiently to meet the forecast demand. Due to the uncertainty and long-term nature of the projects, the Technical Working Group recommends continuing to monitor the load growth on the sub-system and install a capacitor in the Petawawa region to increase the load meeting capability of the sub-system when deemed necessary.

3. Development of the Plan

In Ontario, planning to meet an area's electricity needs at a regional level is completed through the regional planning process, which assesses regional needs over the near-, medium-, and long-term, and develops a plan to ensure cost-effective, reliable electricity supply. A regional plan considers the existing transmission electricity infrastructure, local supply resources, forecast growth and area reliability; evaluates options for addressing needs; and recommends actions to be undertaken.

The process consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified issues and the scope of any recommended planning activities;
3. An IRRP, led by the IESO, which identifies recommendations to meet issues requiring coordinated planning; and
4. A Regional Infrastructure Plan, led by the transmitter, which provides further details on recommended wires solutions

More information on the regional planning process and he IESO's approach to regional planning can be found in Appendix B – Development of the Plan.

In addition to regional planning process, there are bulk planning and distribution planning processes. Distribution system planning is for system at 44 kV and lower, while bulk and regional planning are for higher voltages. Furthermore, regional planning focuses more on a particular, local part of the grid, while bulk planning reviews electricity transfers across the province. There are inherent overlaps in all three levels of electricity infrastructure planning.

The IESO has recently completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review along with the final report is posted on the IESO's website.

3.1 Renfrew IRRP Development

Development of the Renfrew IRRP was initiated in 2021 with the release of the Needs Assessment report. This product was prepared by Hydro One (Transmission) with participation from the IESO, Hydro One (Distribution), and ORPC. Screening for issues was carried out to identify issues that may require coordinated regional planning. The subsequent Scoping Assessment Outcome Report, which was prepared by the IESO, recommended that an IRRP should be developed to address previously identified and new needs in this region due to the potential for coordinated solutions. In 2021, the Technical Working Group was formed to develop a finalized Terms of Reference for this IRRP, gather data, identify near- to long-term needs in the region, and recommend actions to address them.

4. Background and Region Overview

4.1 Region Overview

The Renfrew region is home to Indigenous communities including: Algonquins of Pikwakanagan, Algonquins of Ontario (AOO Consultation Office), Huron Wendat, MNO Ottawa Region Métis Council, and MNO High Land Waters Métis Council. A full list of Indigenous communities that were invited to participate in the regional planning engagements can be found in Section 8.5. The region is also comprised of the following communities: Township of Admaston/Bromley, Township of Bonnechere Valley, Township of Brudenell, Lyndoch, and Raglan, Township of Greater Madawaska, Township of Head, Clara, and Maria, Township of Horton, Township of Killaloe, Hagarty, and Richards, Township of Laurentian Valley, Township of Madawaska Valley, Township of McNab/Braeside, Township of North Algona Wilberforce, Township of Whitewater Region, Town of Arnprior, Town of Deep River, Town of Laurentian Hills, Town of Petawawa, Town of Renfrew, and the City of Pembroke.

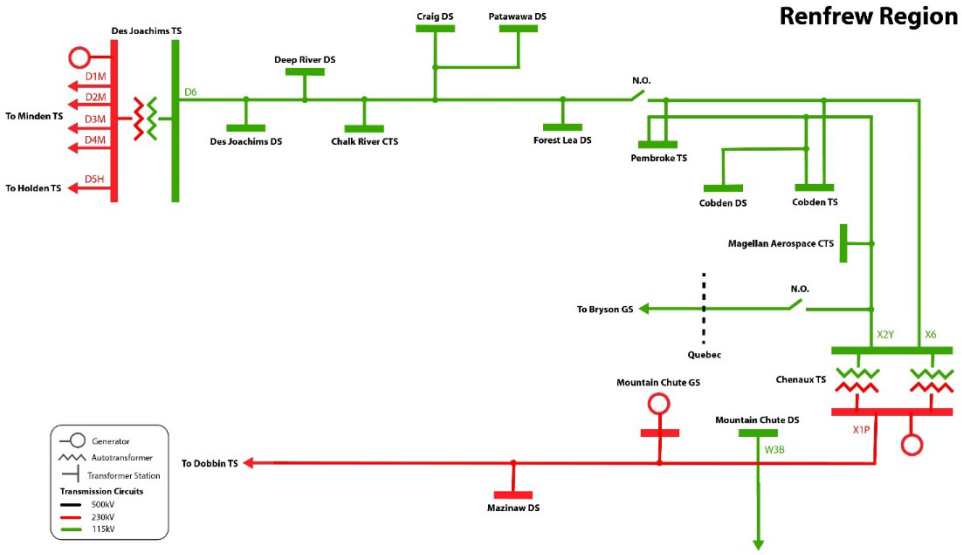
Hydro One Distribution is the main LDC for the region with Ottawa River Power Corp. embedded at Pembroke TS. ORPC is responsible for managing the distribution system for the central Pembroke area. The Hydro One portion of the station is predominantly industrial based. The ORPC portion of the load is largely residential loads. Pembroke is also unique in the fact that it has a tie to the Brookfield generator in Quebec and has been importing energy from the generator since 1893. The generator was established in Pembroke at the same time as the lumber mill and allowed for the first street lighting in Canada. The ownership and management of the generator has changed hands many times but it remains a core characteristic of the city's electrical supply.

Petawawa is the next largest municipality in the region and is served by Craig TS, Craig DS, and Petawawa DS. An industrial customer makes up a significant portion of the Petawawa DS load. The region is also home to two transmission connected customers in Chalk River Nuclear Laboratories and Magellan Aerospace. The majority of the remaining Renfrew region is made up of townships with predominantly residential loading.

4.2 Electrical System

Two hydro electric generation stations supply either end of the transmission system. Power is stepped down from 230 kV to 115 kV at Des Jaochims TS and Chenaux TS. The Des Joachims sub-system consists of 115 kV transmission circuit D6 while the Chenaux sub-system is supplied by the X2Y and X6 transmission circuits. A normally open point is found between Pembroke TS and Forest Lea DS which separates the two sytems under normal operations but can be closed in order to supply the 115 kV system during planned and unplanned outages from either Des Joachims TS or Chenaux TS. The region has two transmission connected customers: Chalk River Nuclear Laboratories and Magellan Aerospace. Figure 2 shows the electric system for Renfrew.

Figure 2 | Single Line Diagram of Renfrew Electric System



4.3 Previous Planning Activities

The most recent cycle of regional planning for the Renfrew region began with a Needs Assessment, carried out by Hydro One, that was published in May of 2021. The Needs Assessment developed a 10 year forecast and identified several needs in the region. Two end-of-life asset issues were addressed: refurbishment of Chenaux T3/T4 Auto transformers and 115 kV switchyard, and the refurbishment of the D6 line from Des Joachims TS to Petawawa DS. Finally, the Needs Assessment identified the station capacity need at Pembroke TS and recommended that the next stage of regional planning, the Scoping Assessment, should determine whether further regional planning coordination is required.

The Scoping Assessment began immediately following the Needs Assessment and was published in August of 2021. This step in the process is lead by the IESO and includes one public webinar to present the Technical Working Group's recommendation on the next steps. Through deliberation it was decided that further coordination and assessing the possibility of non-wires alternatives (NWA) to address the capacity issue at Pembroke TS was necessary which moved the Renfrew region to the IRRP stage.

4.4 Scope of Work

There are several key steps to an IRRP that are taken in order for the Technical Working Group to be able to come to a consensus on what the ultimate recommendations will be for each issue. First is the development of a planning forecast. The Technical Working Group is tasked with analyzing historical demand and then projecting anticipated demand over a 20-year period while taking into account the effect of generation, conservation and demand management, and extreme weather. The IRRP for the Renfrew region produced non-coincident planning forecasts which serve as an aid in identifying transmission system issues.

The Needs Assessment identified a station capacity issues at Pembroke TS but following the completion of the planning forecast several other issues were found. The scope of this IRRP includes station capacity issues at Pembroke TS, Forest Lea DS, Petawawa DS, and examines the Load Meeting Capability (LMC) of both the Des Joachims and Chenaux sides of the transmission system. Details regarding each of these issue is outlined in the Section 6 – Transmission System Issues.

The next steps are then to identify suitable solutions for each of the issues which are covered in the options analysis in Section 7. The IRRP considers wires, non-wires alternatives, including energy efficiency solutions, and accesses each based on cost, feasibility, and timing. Stakeholders are consulted throughout the planning process in the form of individual engagements as well as three public webinars. Finally, recommendations are provided which outline the best course of action as agreed upon by all members of the Technical Working Group.

5. Electricity Demand Forecast

Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in a region. In order for the Technical Working Group to plan for the future transmission system issues of a region, a 20- year planning demand forecast is developed. This section outlines the demand forecast methodology, discusses historical electricity demand trends, development of the planning demand forecasts as well as the expected contributions of conservation and demand management (CDM) and distributed generation (DG) towards reducing the peak demand in the region. By taking all of these factors into consideration the planning demand forecast is developed and is used to plan the transmission grid such that the grid can operate reliably and economically in the long-term. In addition to this, the final sections will examine higher growth scenarios and their impact on the region's transmission system.

5.1 Demand Forecast Methodology

The goal of creating a 20-year forecast is to understand how electricity demand will change in the region, on a station by station basis, in order to understand which parts of the electricity system will require further planning decisions. The planning forecast serves as a reference with the understanding that true, actualized demand may be higher or lower. In order to develop the planning forecast it is important to consider how to treat past electricity demand. Naturally demand fluctuates hour by hour, day by day, and seasonally so the basis of the forecast is annual peak demand. The reference forecast is based on the annual peak as this is the highest demand that the electricity system is expected to experience in the year and must be able to handle in accordance with planning criteria.

The planning forecast is divided into three time horizons: near-, medium-, and long-term. The near-term (one to five years) has the highest degree of certainty and any issues are typically met using regional transmission or distribution solutions. The medium- (five to ten years) and long-term (ten to twenty years) issues will also examine non-wires alternatives such as generation and CDM solutions. In addition to this, a summer and a winter forecast can be developed to account for regions that experience peaking in both seasons. For the Renfrew region both a summer and winter non-coincident forecast were produced.

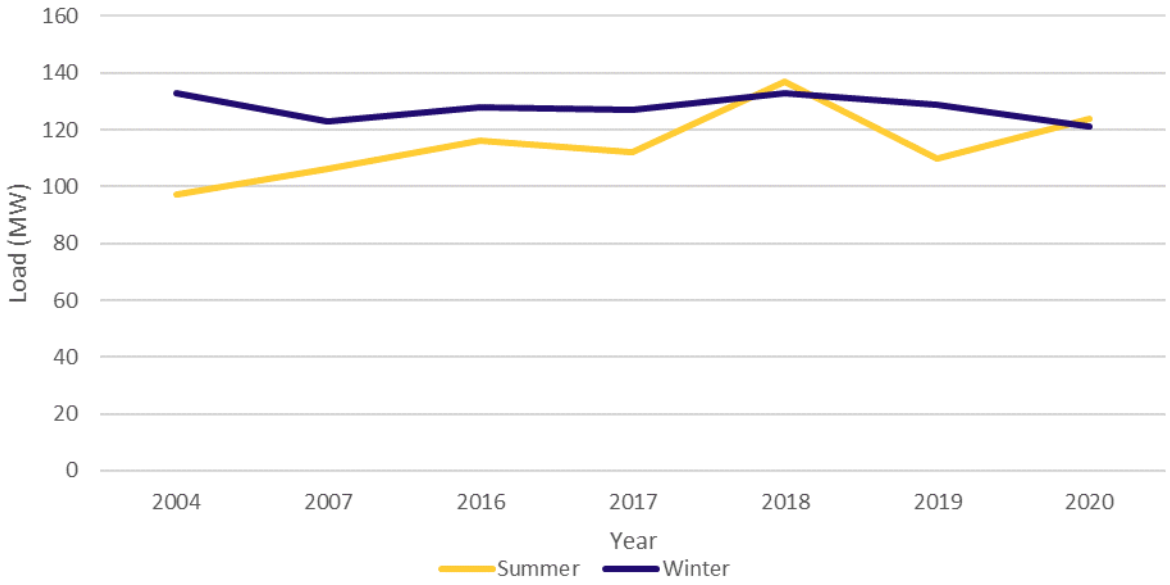
The process of developing the planning forecast starts with the development of the starting points. These consider several factors including historical load, weather, and generation at each of the stations. Using these starting points, distributors develop a 20-year gross demand forecast by accounting for known customer connections, predicted growth in population, and other electricity considerations that planners are privy to. Then, the forecast accounts for the effects of CDM and DG by subtracting them from the demand to produce a Reference Forecast. This is then adjusted for extreme weather which is represented by the hottest year in thirty years, as this will likely be seen over the course of the planning horizon.

Additional details on the demand outlook assumptions can be found in Appendix A.1 - Methodology and Assumptions for Demand Forecast as well as Appendix A.5 for the forecasts themselves. The demand outlook was used to assess any growth-related transmission system issues in the region.

5.2 Historical Electricity Demand

The Renfrew region has historically been a winter peaking region but has seen two of the past five years reach a higher demand in the summer. Going further back to the mid-2000s Figure 3 shows that as a whole the region has seen little growth in peak coincident demand in general. In fact, it appears as though winter demand has slightly decreased while summer demand has been consistently increasing. The region is predominantly made up of residential loads while the larger municipalities such as Pembroke and Petawawa have larger industrial customers.

Figure 3 | Renfrew Historical Coincident Demand



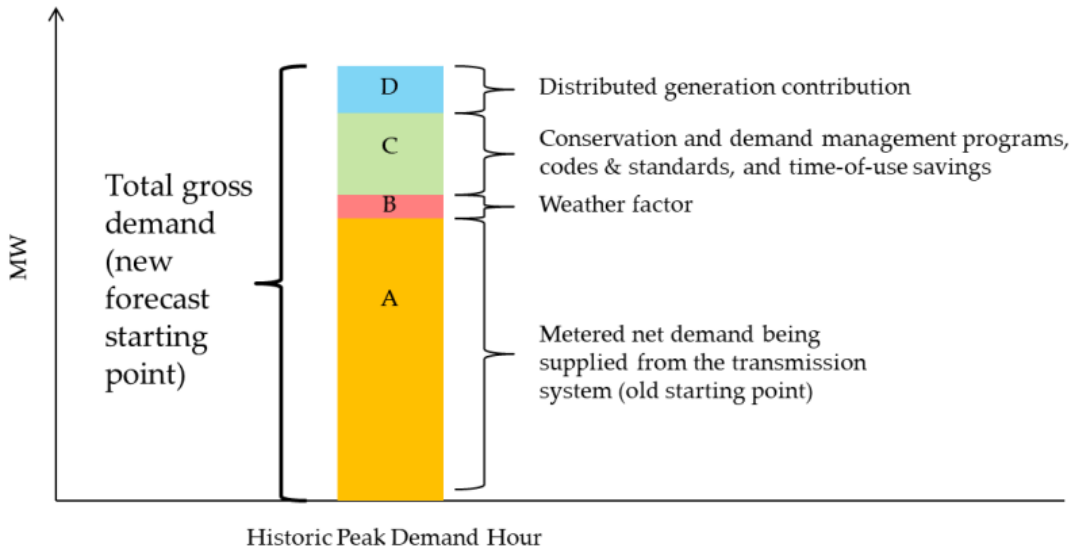
Based on the historical trend it is might be thought that the next twenty years will continue to see little to no growth. However, it is precisely the summer forecast's gradual increase that is telling of trends that could have a significant effect. The ratings of the power system electrical equipment are lower in the summer than in the winter because the natural ambient air cooling is not present and higher temperatures tend to further constrain the equipment's electrical capabilities. The Technical Working Group learned that a vast majority of the residential customer do not have air conditioners. AC units are one of the most impactful contributors to peak loads as they are typically used on the hottest days while the system is seeing its largest demand. Further, residential customers are also mainly using gas heating which means fuel-switching could also increase the winter demand over the next twenty years.

5.3 Gross Demand Forecast Starting Point

The purpose of the starting point is to allow LDCs to forecast their growth from a common place. Gross is used as it is a better approximation of true demand. The starting points are developed by first examining the past five years of historical hourly peak data for each station. For the Renfrew region the base year chosen was 2020 as the IRRP was started in 2021. The hourly demand data for each of the five years is adjusted for normal and extreme weather which is done by taking a weighted average of the 30 years of daily max temperature for the region. The daily peaks for temperature are found for all five years and graphed against daily peak consumption. Certain portions of the data are filtered out to ensure proper correlation is established between temperature and load including outliers, holidays, and weekends. A linear regression is performed to establish a line of best fit and the 90th percentile represents extreme temperature while to 50th percentile is normal temperature.

Typically, the effects of DG and CDM are taken into account as well in order to produce the gross starting point. In the case of Renfrew this was done by identifying the DG in the area and applying a contribution factor which varies by technology type, season of use, and region. The effects of CDM are typically analysed by reviewing the historical demand management programs, codes & standards, and time-of-use savings data available. Figure 4 shows the makeup of the starting point. As mentioned, LDCs then forecast the gross demand for each station based on their own methodologies.

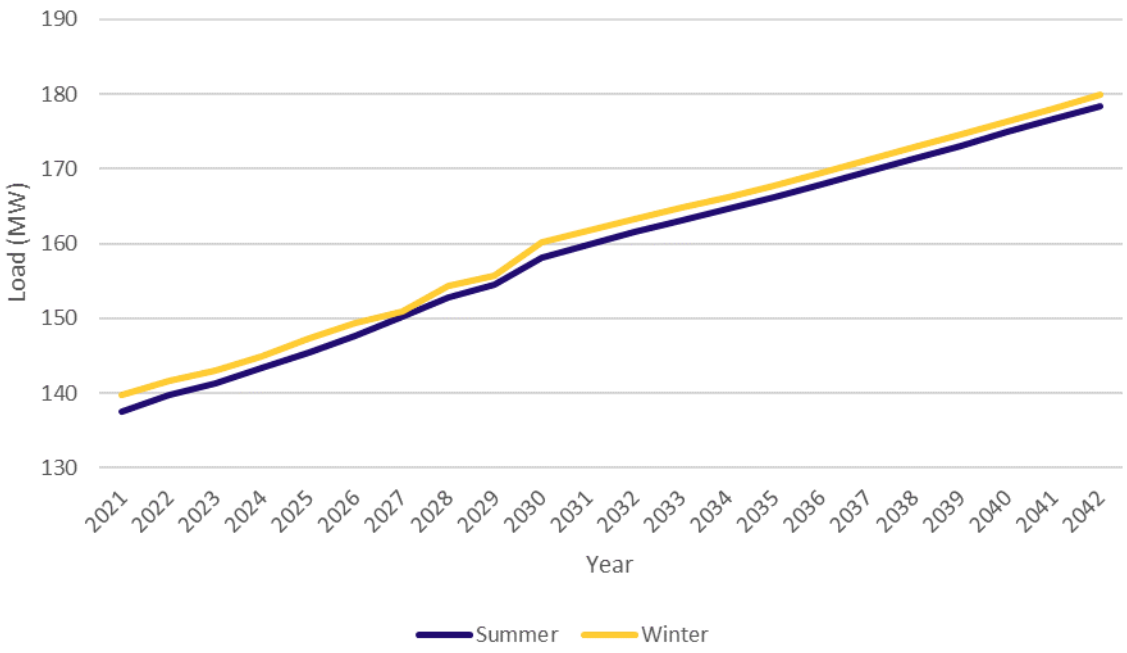
Figure 4 | Load Unbundling to Establish a Gross Demand Starting Point for Forecasting



5.4 Gross Demand Forecast

The gross demand forecast for the 20 year planning period is developed by each LDC. In the case of Renfrew, Hydro One Distribution developed the forecast for all stations with the exception of Pembroke TS which was jointly developed with the embedded LDC ORPC. The LDCs have better insights into the load growth supplied by the distribution stations through their customer connections, management of the station assets, and engagements with electricity customers. The purpose of the gross demand forecast is to serve as a reference which means only load growth that is committed or has a strong chance of materializing is to be considered. Figure 5 shows the summer and winter gross demand forecasts.

Figure 5 | Renfrew Region Non-Coincident Gross Median Demand



5.5 Contribution of Conservation on Forecast

CDM helps in meeting Ontario's electricity needs by reducing demand. This is achieved through a mix of codes and equipment standards amendments as well as CDM program-related activities.

Demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings and through regulation of minimum efficiency standards for equipment used by specified categories of consumers. Program-related activities include the Save on Energy programs being implemented as part of the 2021-2024 CDM framework.

For the Renfrew region, the total forecast conservation savings at the time of summer peak are shown in Table 1 for a selection of the forecast years. These savings are subtracted from the gross median demand forecast as described in Section 5.4. Additional information is provided on Appendix B.

Table 1 | MW Savings from Conservation and Demand Management

Year	2022	2024	2026	2028	2030	2032	2034	2036	2038	2040	2042
Summer Savings (MW)	2	4	6	8	10	12	13	14	14	14	14

5.6 Contribution of Distributed Generation on Forecast

In addition to conservation resources, DG in the Renfrew region is also forecasted to offset peak demand requirements. The resources that were included in the DG forecast reflect resources that have contracts with the IESO as a result of previous procurement programs, such as the FIT and microFIT programs. In the Renfrew region, the contracted DG resources are all solar projects.

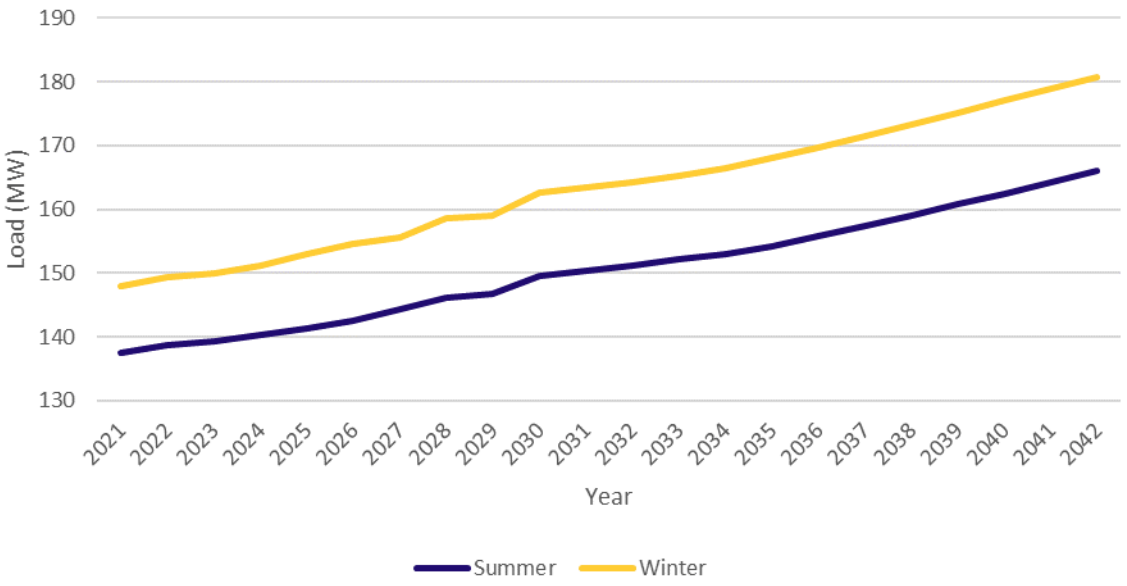
The effective capacity, i.e., the MW output at the time of regional peak, was determined at a resource level, and the data was aggregated at a station level in order to put together a forecast specifying the estimated peak demand reduction due to DG output. From 2021 to 2042, the expected annual peak demand contribution of contracted DG in the Renfrew region is 1.7 MW. The DGs included in the Renfrew IRRP are connected from the following stations:

- Deep River
- Des Joachims
- Cobden
- Pembroke

5.7 Planning Demand Forecast

In order to determine whether transmissions system issues exist it is important to consider the net demand for each station. The net demand represents the peak load level that the transmission system actually experiences and needs to serve. The final net demand forecast, adjusted for extreme weather, for the Renfrew region can be seen in Figure 6. The growth seen here is consistent with the electricity trends that have been noted throughout the report. The planning forecast for each of the stations in the region can be found in Appendix A.5. The planning forecast is used to determine where the issues in a region are and the Technical Working Group ensured the accuracy of the forecast by meeting with stakeholders in those areas to inquire about specific electricity plans.

Figure 6 | Renfrew Region Non-Coincident Extreme Weather Planning Demand Forecast



5.8 Sensitivity Scenario: Higher Growth Forecast

The concept of sensitivity is an important consideration for the planning process. It refers to the idea of stressing a system or examining alternative scenarios. The previous sections have dealt with a reference scenario which is akin to a middle-of-the-road path. It has a higher degree of certainty and by nature discounts extreme growth or extreme decline. Growth scenarios are examined when there is a trend or large project not considered in the reference forecast. Two such scenarios were identified during the planning process. Through discussions with stakeholders it was discovered that two prominent electricity customers in the Renfrew region have tentative plans to increase their load consumption on the order of 20 MW each. The customers are on the Des Joachims sub-system so this IRRP examined one growth scenario where a single increase takes place as well as a scenario where both increases take place. These scenarios occur in the long-term and due to their uncertainty will not have formal recommendations, however, the IRRP will provide insight into how the transmission system can be modified to accommodate this potential growth.

5.9 Hourly Forecast Profiles

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for certain station with identified needs were developed to characterize their needs with finer granularity. The profiles were based on historical load data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. These profiles were used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of generation and distributed energy resource options.

Additional load profile details including hourly heat maps for each need can be found in Appendix D. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Real-time loading is subject to various factors like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are only used to select suitable technology types and roughly estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of implementation of the plan.

6. Transmission System Issues

Based on the demand outlook, system capability, application of provincial planning criteria, and the transmitter's identified end-of-life asset replacement issues, the Renfrew IRRP Technical Working Group determined transmission system issues in the near-, medium-, and long-term. This section describes the capacity issues in the Renfrew region. No end-of-life or reliability issues were identified as part of this IRRP cycle but the methodology is still described below.

6.1 Transmission System Issues Methodology

Based on the application of ORTAC and NERC TPL 001-4 Standard, the Technical Working Group identified transmission system issues related to local or regional reliability requirements for the following categories:

- **Station Capacity Issues** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.
- **Supply Capacity Issues** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the LMC of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL 001-4. LMC studies are conducted using power system simulations analysis.
- **End-of-life Asset Replacement Issues** are identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset, and its condition. Replacement issues identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement issues identified in the medium- to long-term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term issues should reflect the potential for the need date to change as condition information is routinely updated.

- **Load Security and Restoration Issues** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC. No load security and restoration issues were identified as part of this IRRP.

6.2 Near- to Medium-Term Needs

6.2.1 Station Capacity Issues

Station Capacity Issues have been identified for Pembroke TS, Forest Lea DS, and Petawawa DS.

6.2.1.1 Pembroke TS Capacity Issue

Pembroke TS is owned by Hydro One Transmission and managed by Hydro One Distribution while Ottawa Power River Corp is an embedded customer and LDC. Pembroke TS has three distribution feeders that supply both LDC loads. Hydro One supplies Pembroke DS and Greenwood DS as well as other larger commercial and industrial customers while ORPC utilizes two of the distribution feeders to supply seven of their own distribution stations throughout the core of the city. The distribution feeders that supply the core part of the city are also tied with the Brookfield generator from Pontiac Hydro, the details of the relationship with the generator can be found in section 4.1.

The planning forecast confirms and refines the capacity issue at Pembroke TS. Based on the load growth from the demand forecast the issue will grow to approximately 14 MW in the summer and 12 MW in the winter. The summer loading is more constraining as the equipment ratings in the summer are lower. The Technical Working Group met with key industrial customers to inquire about future plans and confirmed the accuracy of the planning demand forecast.

Figure 7 | Summer Non-Coincident Demand Forecast for Pembroke TS

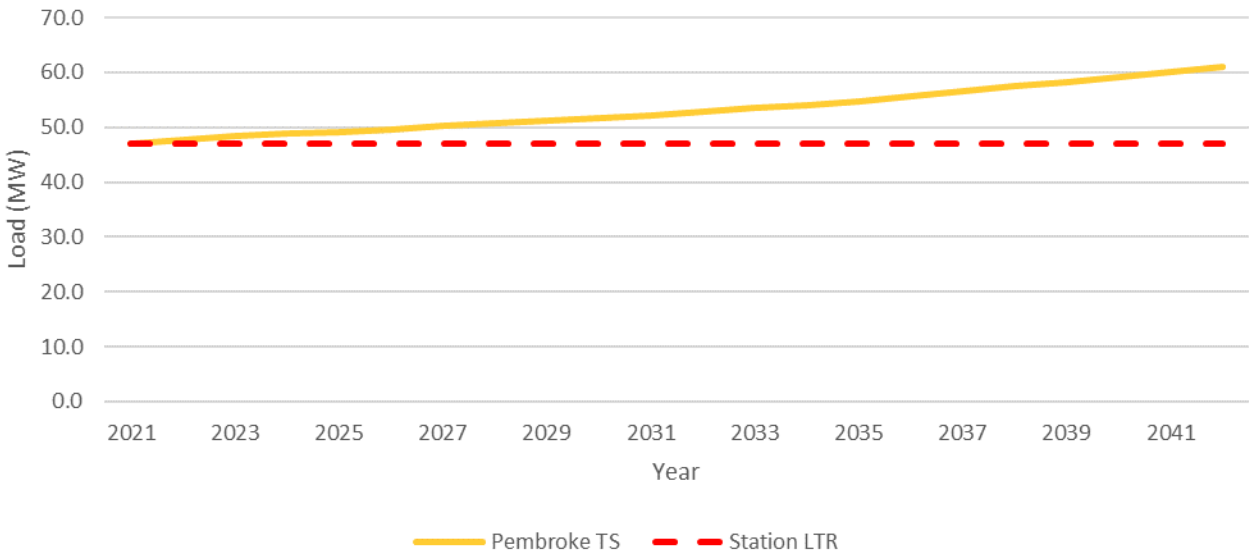
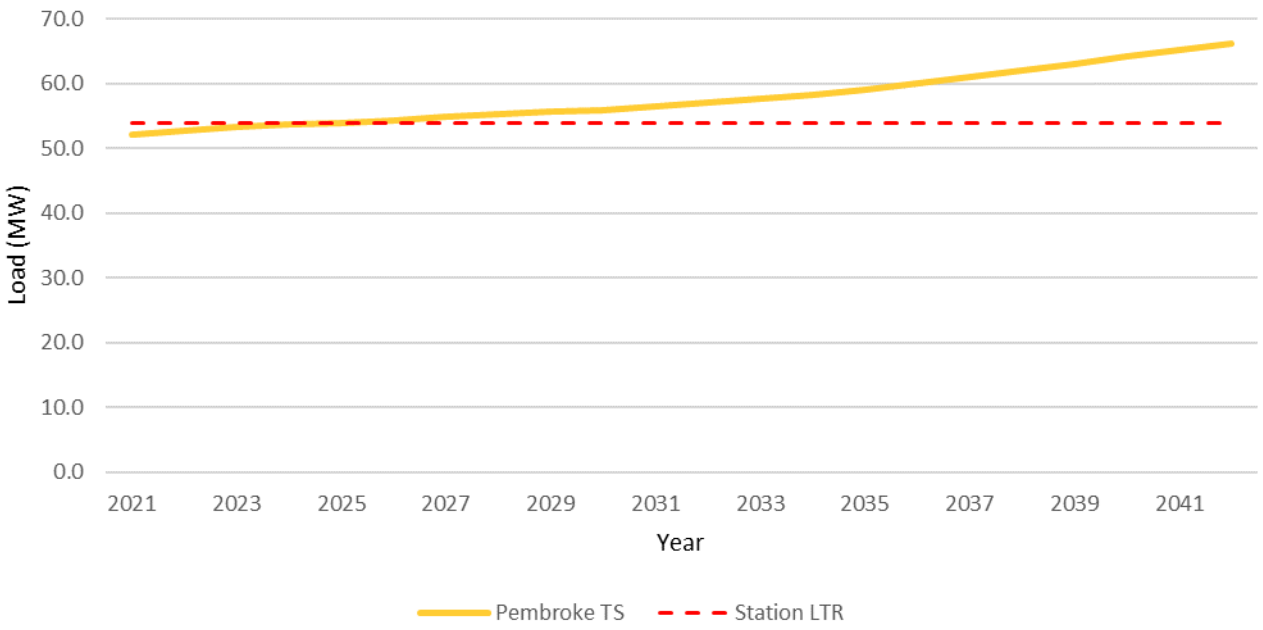


Figure 8 | Winter Non-Coincident Demand Forecast for Pembroke TS



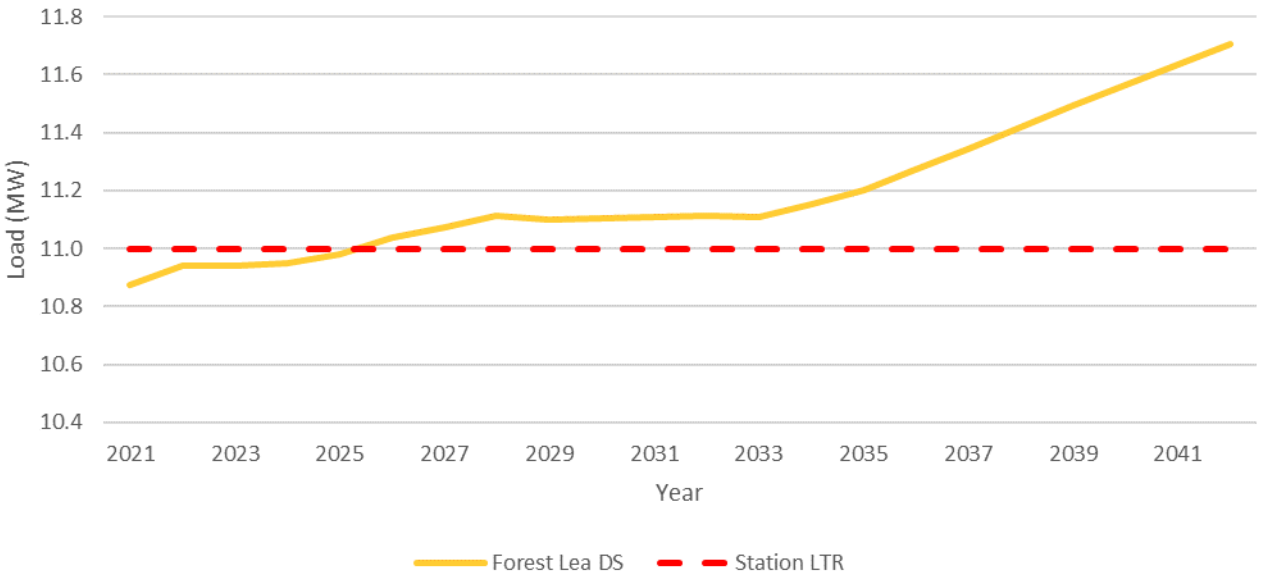
6.2.1.2 Forest Lea DS Capacity Issue

Forest Lea DS is located in Laurentian Valley Hills, just outside the city of Pembroke. It is near the end of the circuit D6, close to Petawawa DS and Craig DS. The station is owned by Hydro One Distribution and has two 7.5 MVA, 115 kV to 13.4 kV, stepdown transformers that were installed in 1974. They are in good working condition and have not been targeted for replacement or refurbishment in a capital program as of the publishing of this report. The station's peak demand currently exceeds its LTR in the summer by approximately half a megawatt and will increase to nearly a full megawatt by 2042 as seen in Figure 10. In the winter, the station is expected to reach its LTR by 2025 and exceed that rating by just over half a megawatt by 2042 as seen in Figure 9.

Figure 9 | Summer Non-Coincident Demand Forecast for Forest Lea DS



Figure 10 | Winter Non-Coincident Demand Forecast for Forest Lea DS



6.2.1.3 Petawawa DS Capacity Issue

Petawawa DS is supplied by circuit D6 and is located at the end of the circuit alongside Craig DS. The station is owned by Hydro One Distribution and has two 7.5 MVA, 115 kV to 13.4 kV, stepdown transformers that were installed in 1976. They are in good working condition and have not been targeted for replacement or refurbishment in a capital program as of the publishing of this report. The station's load is predominantly made up of one large industrial customer with the rest being the town of Petawawa. Two outreach meetings were held with the customer to finalize the planning forecast and the outcomes of the discussions made it clear that there is both medium- and long-term plans for further electricity consumption. The final forecast can be seen in Figure 11 which includes the medium-term expansion project. The station is anticipated to reach its limit by 2030 in the summer and based on the latest forecast will be within its winter rating. Further, the engagement also revealed a very sizeable heating load at the industrial customer which will need to be converted as part of the Canadian Net-Zero Emissions Accountability Act. This development is one of the basis for the growth scenarios developed as part of this regional plan and further details can be found in Section 6.3. It is considered a growth scenario as opposed to part of the planning forecast due to the uncertainty of the size and exact timing of the project.

Figure 11 | Summer Non-Coincident Demand Forecast for Petawawa DS

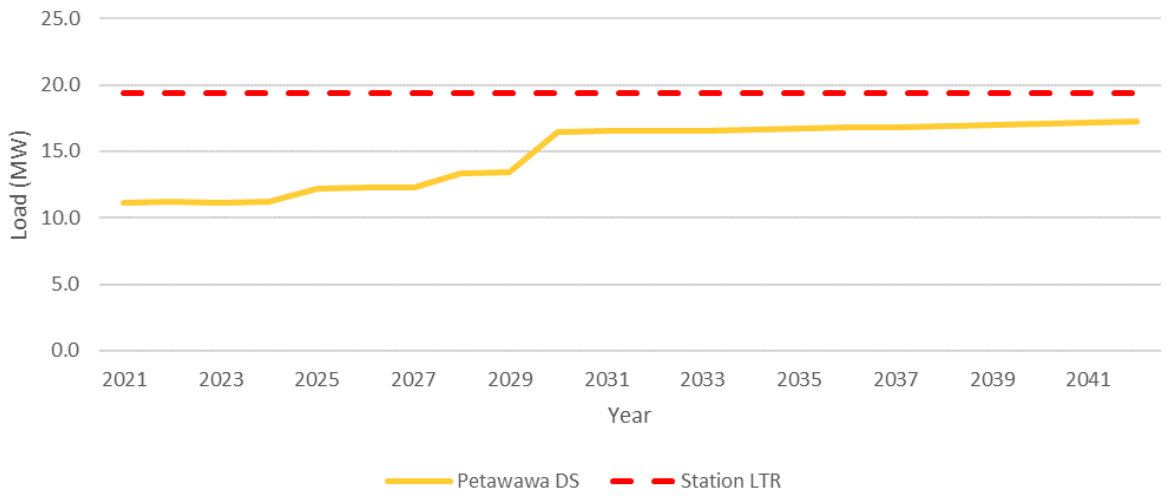
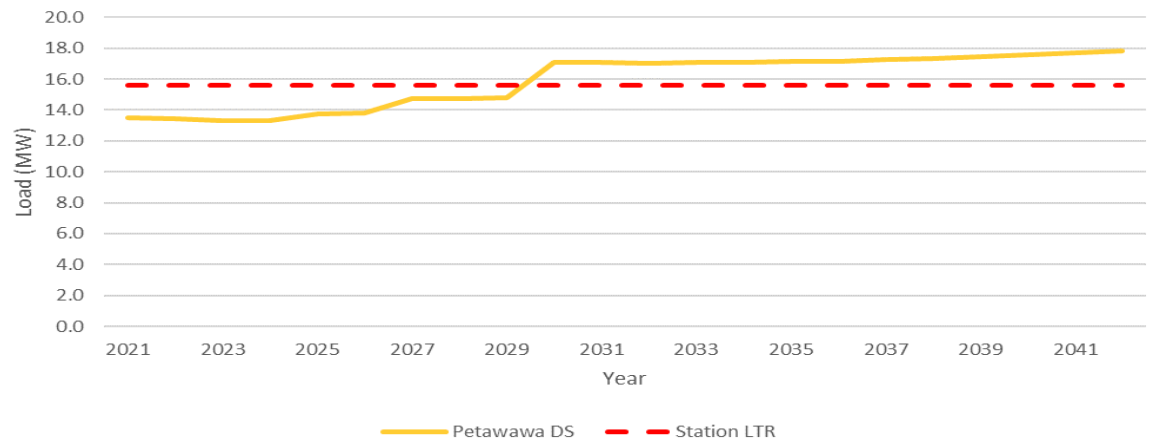


Figure 12 | Winter Non-Coincident Demand Forecast for Petawawa DS



6.3 Long-Term Needs

6.3.1 Supply Capacity Issues

6.3.1.1 Des Joachims Sub-System Capacity Issue

The Renfrew electricity system is comprised of two sub-systems, the Des Joachims and Chenaux sub-systems. The Des Joachims sub-system refers to the transmission line D6 and the generating station in the Western part of the Renfrew Region called Des Joachims TS while the Chenaux sub-system refers to the transmission lines X2Y and X6 and associated stations. As part of the planning process the LMCs are determined for the relevant parts of the transmission system. It was found that there are no long-term issues under the planning forecast for the Chenaux sub-system. Growth scenarios were developed for the Des Joachims sub-system and long-term issues were identified. With one element out and a contingency to a generator at Des Joachims TS, under peak coincident demand and low generation conditions, there is a voltage change violation at end-of-line stations such as Petawawa DS, Forest Lea DS, and Craig DS on the Des Joachims sub-system. That LMC is approximately 80 MW as seen in Figure 13.

Figure 13 | Des Joachims Side Summer Coincident Load Forecast



7. Options and Recommendations

This section describes the options considered and recommendations to address the issues in the Renfrew Region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new infrastructure to increase the LMC of the area. These are commonly referred to as "wires" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing LMC. These are commonly referred to as "non-wires" options and can include things like local utility scale generation, distributed energy resources, demand response, or energy efficiency.

Section 7.1 begins with a more in-depth overview of all option types considered in IRRPs. The IESO utilized a screening approach to assess which needs would be best suited to a detailed assessment for non-wires options, this is first described in Section 7.2. Section 7.3 covers the options and recommendations for meeting the near- to medium-term issues, and is followed by Section 7.4 which discusses the options and recommendations for the long-term. The summary and next-steps is found in in Section 7.5.

7.1 Options Considered in IRRPs

Wires options are developed by designing transmission reinforcements or control actions that are appropriate for the specific limiting phenomenon (voltage, thermal, stability, etc.) of each need. These options are developed through discussions with the Technical Working Group. These wire options consider the capital cost of the line and stations plus the energy cost associated with the unserved energy profile.

The high-level cost estimates for wires options are provided by the transmitter, Hydro One. The RIP, following the IRRP, will perform additional detailed analysis and refine these cost estimates before implementation work begins. The IESO will continue to participate in the Technical Working Group during the RIP and revisit these recommendations if costs estimates differ significantly.

To select a non-wire options an hourly load profile is first created as described in Section 5.9. The most suitable technology type and capacity is chosen by examining the "unserved energy" profile which is the hourly demand above the existing LMC. The profile indicates the duration, frequency, magnitude, and total energy associated with each need.

Cost estimates for generation and other non-wires alternatives are based on benchmark capital and operating cost characteristics for each resource type and size. The use of new natural gas-fired generation is considered in the economic analysis for illustrative purposes to represent the lowest cost of generation. The use of energy storage such as a lithium nickel manganese cobalt oxide (NMC) batteries is also considered as it becomes competitive due to declining technology costs and the expectation of increasing carbon prices in line with federal policy. Conservation demand management (CDM) are also non-wires alternatives that can be considered based on regional availability.

For all of the above options, the system capacity value if applicable is "credited" back to arrive at the net cost to meet local reliability needs. This is done to ensure a level playing field comparison between resources that provide capacity and wires options that address the local need but do not provide system capacity benefits.

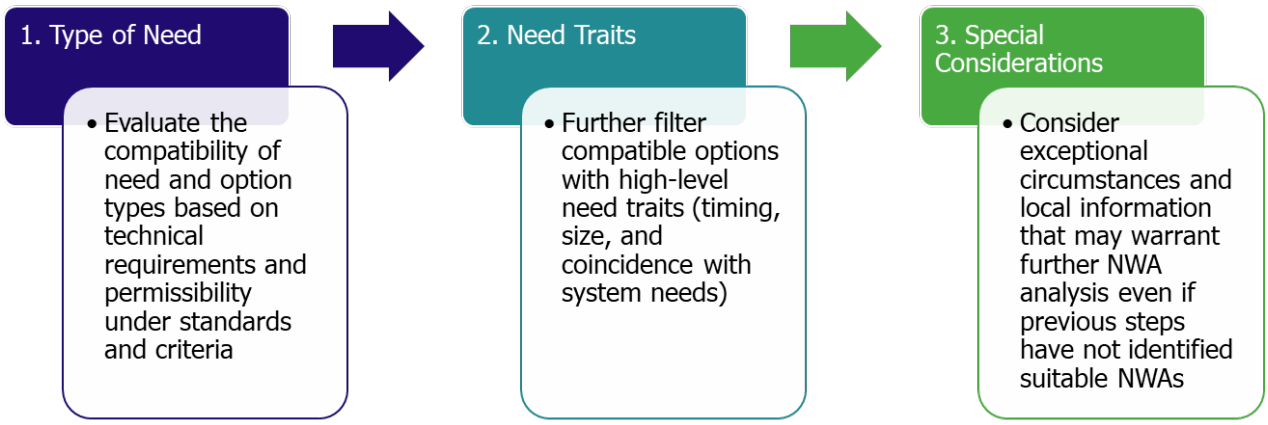
Both the upfront capital and operating cost of the wires options, generation, and distributed energy resources are compiled to generate levelized annual capacity costs ($/kW-yr) over the lifespan of the asset in question (for Renfrew a 45-year lifespan is assumed for the station infrastructure) for each option. The net present value (NPV) of these levelized costs are the primarily basis through which options are compared below. Unless stated otherwise, the costs are net present values and in 2021 CAD dollars. The list of assumptions made in the economic analysis can be found in Appendix C.

7.2 Screening Options

As explained in Section 7.1, different options can be developed to meet local needs during an IRRP based on the needs requirement. Options are then evaluated to recommend the most cost-effective and technically feasible solution. This process is complemented by considerations for stakeholder preferences and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed NWA analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 14.

Figure 14 | IRRP Screening Mechanism



Note that the screening mechanism only acts as a guideline; many other considerations for its application in the Renfrew IRRP are described in the following sections.

7.2.1 Non-Wires Options for the Capacity Needs

In general, non-wires options can resolve supply and station capacity needs by reducing net load in the affected area. For station capacity needs specifically, these options must be connected downstream of the limiting step-down transformer.

7.2.1.1 Pembroke TS

As described previously in Section 6.2.1.1, there are forecast station capacity needs at Pembroke TS. Since the capacity need at Pembroke TS is existing today, and grows to 14 MW and 12 MW in the summer and winter, respectively, a DR solution was screened out as prior years' auction indicates there isn't sufficient DR potential in the east zone for 16 MW for both summer and winter seasons.

7.2.1.2 Petawawa DS

As described in Section 6.2.1.2, there is a forecast station capacity need at Petawawa DS. Due to consideration of the growth scenario, a DR solution was screened out. Further, in 2042 there will be a station capacity need at Petawawa DS 47% of the time in July, which is not a good candidate for DR. Lastly, CDM was screened out as the station supplies one large industrial customer which greatly reduces the available programs and initiatives.

7.2.1.3 Forest Lea DS

For Forest Lea DS, all options except transmission-connected generation were developed in further detail.

7.2.1.4 Des Joachims Sub-System Supply

Due to the nature of supply capacity needs, most non-wires options can be potential solutions – either alone or as a part of an integrated package of recommendations. However, for the Des Joachims sub-system, the need was only forecast to emerge under the growth scenario. To focus non-wires alternative analysis on the needs emerging under the reference forecast, only wires options were evaluated.

7.2.1.5 Summary of Screening Outcomes

Table 2 | Results of Renfrew IRRP Screening

Need Type	Impacted Element	Options Screened In	Options Screened Out
Station capacity	Pembroke TS	Wires, DG, CDM	Transmission-connected generation, DR
Station capacity	Petawawa DS	Wires, DG	Transmission-connected generation, DR, CDM
Station capacity	Forest Lea DS	Wires, DR, DG, CDM	Transmission-connected generation
Supply capacity	Des Joachims Sub-system	Wires	Transmission-connected generation, DR, DG, CDM

7.3 Options for Meeting Near- to Medium-Term Issues

7.3.1 Options for Meeting Pembroke TS Station Capacity Need

Pembroke TS supplies both Hydro One Distribution and ORPC load. The embedded ORPC load is supplied from two of the existing feeders. These feeders provide both a normal and back up supply to seven ORPC owned distribution stations throughout the core of the city. The feeders mentioned distribute power at a voltage of 44 kV which is stepped down at the DS. The station LTR is currently exceeded by 1 MW and this is forecast to increase to 14 MW, in the summer, over the course of the 20 year forecast.

7.3.1.1 Transmission Options

Two feasible wires options were considered:

- Building a new HVDS, or
- Building a new DESN station, or "TS".

These options differ both in the capacity they are capable of offering and the secondary, or distribution voltage, available.

The HVDS would be built by converting the existing Pembroke DS to an HVDS. It would be connected to only one of the two transmission circuits that currently supply Pembroke TS, X2Y or X6. An HVDS would provide 18 MW of capacity at a cost $13M (NPV), which includes $11M (NPV) for building the station and at a least an additional $2M (NPV) for distribution costs. Due to configuration of the existing system, the HVDS would be used to supply existing load, freeing up space for new load on Pembroke TS. The new HVDS would supply existing ORPC load which would split the ORPC distribution system into two distinct sub-systems: the existing system and a new radial system. The existing system utilizes the two feeders from Pembroke TS with ties between them to improve reliability and flexibility during planned outages and contingencies. Further, ORPC and Hydro One Distribution utilize different voltages which will require further analysis and cost in order to implement the HVDS solution.

Maintaining two separate systems with different levels of reliability could prove to be an operational challenge and any growth beyond the forecast would likely necessitate the expansion of this new less reliable radial 12 kV system in the future, once the capacity is exceeded. As the HVDS would only have one upstream transmission supply, this also represents a decrease in reliability over the LDC's existing supply arrangement at Pembroke TS. From a capacity standpoint, this option leaves 2 MW of remaining capacity at the new HVDS and 2 MW of remaining capacity at Pembroke TS at the end of the 20 year forecast period, which would not be sufficient to accommodate a high growth scenario.

The other option is to build a new DESN station, or TS, near the existing Pembroke TS, connected to both the X2Y and X6 circuits. It would cost approximately $28M (NPV) to build the station. Transferring existing load to the new station is estimated to have negligible cost, as no new feeders would need to be constructed. While the new supply station would be rated for 47 MW, the station will only be able to supply up to 36 MW of load due to upstream transmission constraints on 115 kV circuits. By transferring 6 MW of Greenwood DS load and 12 MW of Hydro One Distribution load to the new TS, ORPC will be able to supply their 20 year forecasted growth using their existing distribution system. This leaves 18 MW of capacity at the new TS and 4 MW of capacity at the existing TS. Compared to the HVDS option, the TS option provides higher levels of reliability, consistent with what the LDCs currently experience and provide today, as it is a dual supply station, maintains ORPC's current distribution configuration which provides back-up supply, and provides 22 MW of spare capacity for the future versus 4 MW. These additional benefits would come at an incremental cost of $15M (NPV) compared to the HVDS option.

7.3.1.2 Non-wires Options

The non-wires alternative options considered for Pembroke TS were distributed generation and additional energy efficiency. For the distributed generation option gas generation and storage were evaluated. Solar and wind were not considered due to a lack of alignment between their typical production profiles and the hourly need requirement. The gas generation option was based on costs for a 16 MW reciprocating engine located in eastern Ontario. A 93% effective capacity for system benefit was assumed in the analysis.

This option was estimated to cost of $47M (NPV). The storage option required 16 MW of capacity and 10.3 hours of storage. This option was estimated to cost $96M (NPV). The development of cost for the storage option assumed a 10 MW capacity battery with 10 hr reservoir would be installed in 2026, with an additional 6 MW installed in 2035.

Lastly, analysis of the potential for additional energy efficiency, on top of the already committed CDM programs, reveals there is the potential for approximately 6 MW of additional savings over the 20 year forecast at a cost of $31M (NPV) by 2038. This option would be insufficient to meet the need requirement of 10 MW by 2038.

7.3.1.3 Recommendations

Building a new TS in the Pembroke area will maintain current levels of reliability, will allow ORPC to continue growing their system under the current methodologies and level of distribution reliability, and allows for a substantial amount of new capacity for flexibility in meeting long-term demand compared to the HVDS option. However, this comes at an increased upfront cost for the capacity. While the technical challenges and reliability limitations associated with the HVDS are considerable, the Technical Working Group has decided the difference in cost warrants a more detailed study of the costs of the proposed HVDS connection and distribution impacts in the RIP to confirm the additional cost associated with the TS solution is warranted. The targeted in-service date for a new station in Pembroke is 2027.

7.3.2 Options for Meeting Petawawa DS Station Capacity Need

Petawawa DS supplies the town of Petawawa and a large institutional customer. The majority of the load, an upwards of 80%, is consumed by the customer. Engagements with the customer have revealed that there are developments planned for expanding several buildings on their campus which led the Technical Working Group the revise the draft forecast. The forecast now estimates the station will be overloaded in the near-term by approximately 2-3 MW.

7.3.2.1 Transmission Options

There were several wires options identified to provide the additional capacity. First, the transformers at the station could be upgraded to a larger size which would add only 3 MW of incremental capacity to the station rating. This comes at a cost of approximately $5M (NPV). Alternatively, a new HVDS could be built at a cost of approximately $10M (NPV) and would add an additional 18 MW of incremental capacity. The working group also examined the feasibility of conducting a load transfer to Craig TS but, as that station does not have a significant amount of spare capacity, it was deemed that load transfer is not suitable in this case.

The upgrade of the transformers would meet the forecast demand but offer no spare capacity. A new HVDS, however, is $5M more expensive but provides significantly more capacity and allows for flexibility to meet the challenge presented in the growth scenarios.

7.3.2.1 Non-wires Options

From a non-wires alternative perspective, a number of options were considered but only a generation option was developed as it fit the nature of the need profile. The generation option evaluated was a simple cycle gas turbine (SCGT) facility for the 2 MW need. This comes at a cost of $11M in net-present value. Wind and solar resource options were not evaluated as the load requirement does not match their production profiles. Based on comparison of the costed gas generation option to the lower cost wires options, a storage solution was not evaluated as it would be higher cost than the gas option.

7.3.2.3 Recommendations

Building a new HVDS for the Petawawa DS station capacity need is recommended. The targeted in-service date for the new HVDS is 2027. This solution will provide ample capacity to meet the immediate planned growth in demand from the institutional customer as well as provide flexibility in the future as the customer converts their gas heating load. This is the most cost effective solution that ensures capacity for the long-term growth of Petawawa.

While comparable on a cost basis, the options of incremental energy efficiency and replacement of existing station transformers would provide insufficient margin of available capacity in the area to manage the high growth scenarios at Petawawa DS, resulting in the electricity system potentially limiting the ability of customers to electrify in a manner consistent with their plans or policies.

7.3.3 Options for Meeting Forest Lea DS Station Capacity Need

Forest Lea DS has a station limit of 8.6 MW in the summer and is currently over that limit but will only exceed it by 1 MW in the 20 year forecast.

7.3.3.1 Transmission Options

A number of wires solutions were considered, including distribution load transfers to nearby stations, improving the ratings of the existing station transformers and building a new HVDS. First, the possibility of transferring load to a nearby station was explored for both existing ties with Pembroke DS and Craig DS. A 1 MW load transfer to Craig DS can be done with minimal work resulting in a capital cost of only $50k (which is equal to $55k (NPV)). A transfer to Pembroke DS, although technically feasible, would currently result in a further overload of the upstream Pembroke TS. Depending on the solution executed for the Pembroke station capacity issue it could be possible to offload Forest Lea DS but for these reasons transferring load to Craig DS is favourable.

There are two options for upgrading the capacity of Forest Lea station: upgrading the transformers or installing fan cooling and a SCADA monitoring system to the existing transformers. The former option adds 10 MW of capacity for a capital cost of $4.5M ($4.4M NPV) while the latter provides 4 MW at a capital cost of $0.6M ($0.6M NPV).

Building a new HVDS for the Forest Lea area is also possible and would add 18 MW of load at a capital cost of $12M ($11.7 M NPV). However, this option provide capacity that far exceeds what would be required, even under consideration of a high growth scenario.

7.3.3.2 Non-wires Options

For the need at Forest Lea DS, demand response, distributed generation (storage), and incremental energy efficiency were evaluated. The demand response option is based on prior capacity auction potential of an additional 1 MW in the area to meet the need and the 2018-2021 costs from capacity auctions. The effective capacity for demand response is 69% and is based on the summer effective capacity in the 2022 APO. This option comes at a cost of $1M (NPV). The storage option examined is a 1 MW battery with a 4-hour battery life and a cost based on National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB). This resource option is estimated to cost $1.6M (NPV). Lastly, analysis of the potential for additional system cost effective energy efficiency, on top of the already committed CDM programs, reveals there is approximately 1 MW of achievable potential over the 20 year forecast at a cost of $6.1M (NPV) by 2038. However, due to the small amount of load supplied by Forest Lea DS there is a higher degree of uncertainty associated with realizing these additional savings given the top-down estimate approach and there is no margin of potential additional savings when compared to the identified need.

7.3.3.2 Recommendations

Since the need at Forest Lea DS is existing and is only expected to grow to just over 1 MW in the long-term it is recommended that the 2 MW load transfer to Craig TS be executed. The targeted date for this load transfer is 2026.

In the event of further load growth beyond the reference forecast, it is recommended that the upgrade to fan cooling at the station and the installation of SCADA monitoring be implemented to allow for an additional 4 MW limit increase.

7.4 Options for Meeting Long-Term Issues

7.4.1 Options for Meeting the Des Joachims Sub-System Capacity Issue

During the course of the engagement stage of the IRRP two growth scenarios were identified for the Des Joachims Sub-system. Each scenario signifies approximately 20 MW of additional growth in the form of a large scale energy project. If one of these events were to take place it would bring the sub-system to its LMC. At this level of loading, and other assumptions, there would be voltage issues at the end of the line at stations like Forest Lea DS and Petawawa DS. The LMC can be improved to 90 MW by installing shunt capacitors at the end of the transmission line (D6). By examining the two growth scenarios outlines, growth scenario 1 being an additional 20 MW and growth scenario 2 being an additional 40 MW, the current LMC will be violated by both scenarios while the improved LMC can handle growth scenario 1 but not growth scenario 2.

7.4.1.1 Transmission Options

Installing capacitor banks at one of these stations would improve the LMC by approximately 10 MW. This means that for the more aggressive load growth scenario the Des Joachims sub-system would be 10 MW over what the system can adequately supply. In this scenario a future cycle of regional planning would need to examine options including a new transmission line.

7.4.1.2 Recommendations

As both growth scenarios are in the mid- to long-term and have a fair amount of uncertainty it is recommended that the Planning Technical Working Group continues to monitor the state of the projects and triggers the capacitor upgrade if a need were to arise ahead of the next planning cycle.

7.5 Summary of Actions and Next Steps

Table 3 | Summary of Actions and Next Steps

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
Pembroke Station Capacity	Hydro One Transmission	Build a new station; conduct further analysis during the RIP period to finalize decision between new TS or HVDS	2027
Forest Lea Station Capacity	Hydro One Distribution	Transfer 2 MW of load from Forest Lea DS to Craig DS using existing tie	2025-2026
Petawawa Station Capacity	Hydro One Distribution	Build a new HVDS transformer station at Petawawa	2027
Des-Joachims Sub-System System Supply	IESO	Monitor load growth in the area and wait to trigger investment	N/A

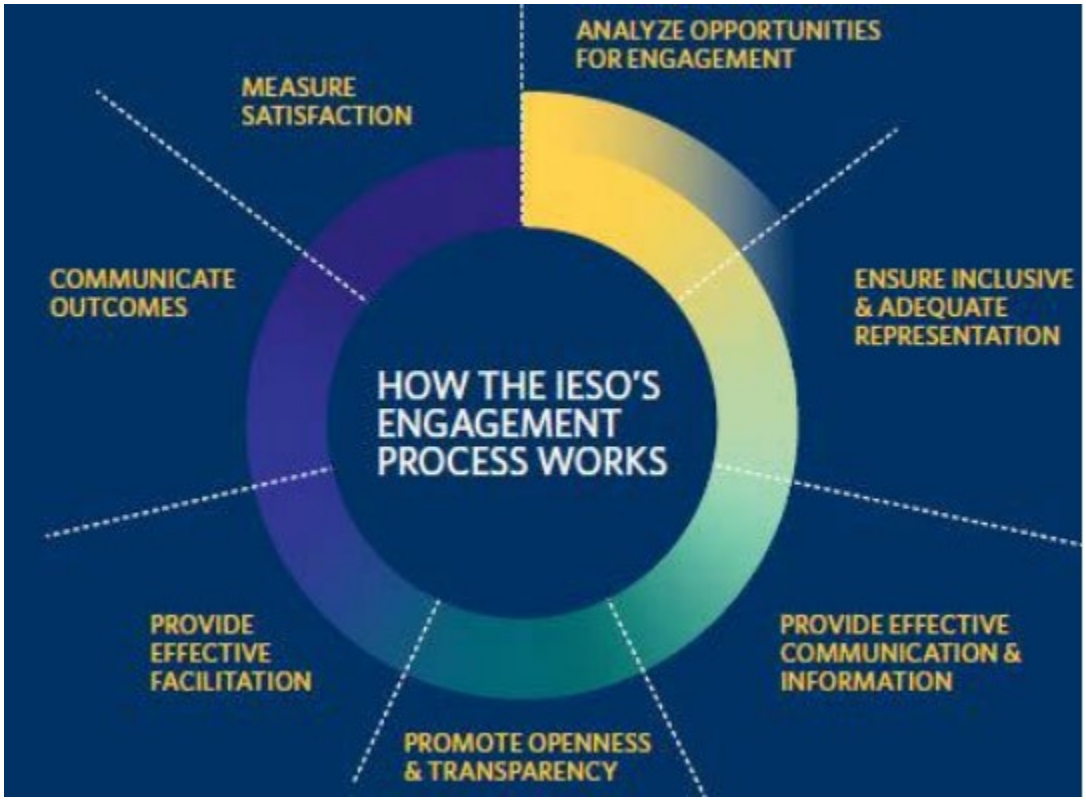
8. Engagement

The engagement process is critical to the development of the IRRP. Identifying, interacting, and collaborating with stakeholders in the region allows for the collection of knowledge and input which directly shapes how the plan is developed. Engagement is conducted in various forms and the details of the process as well as the feedback heard for the Renfrew region is described in this section.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP[1]. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 15 | IESO's Engagement Principles



[1] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

8.2 Developing an Engagement Plan for Renfrew

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region. As part of the engagement process, it is important to seek out information and input on the region's electricity needs and growth plans. This helps to ensure that the IRRP captures the most accurate and up-to-date information.

Creating the engagement plan for this IRRP involved:

- Discussions to help inform the engagement approach for the planning cycle;
- Communications and other engagement tactics to enable a broad participation, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities who may have a direct impact on this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to feedback throughout the engagement process;
- Regular communication with interested communities, rights-holders and stakeholders by e-mail or through the IESO weekly Bulletin;
- Public Webinars;
- Targeted one-on-one outreach with specific stakeholders and communities to ensure that their identified needs are addressed.

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this new round of planning and establish new relationships with communities and stakeholders in the region where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report for the Renfrew Region. An invitation was sent to targeted municipalities, Indigenous communities and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the draft Renfrew Scoping Assessment Outcome before it was finalized. A public webinar was held in July 2021 to provide an overview of the regional electricity planning process and seek input on the high level needs identified and proposed approach. The final Scoping Assessment was posted later in August 2021 which identified the need for a coordinated regional planning approach to develop the first IRRP for the Renfrew Region.

Following the finalization of the Scoping Assessment, the launch of a broader engagement initiative followed with an invitation to subscribers of the Renfrew Region to ensure that all interested parities were made aware of this opportunity for input.

Three public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses and other stakeholders and written feedback was collected over a 21-day comment period following each webinar.

The three stages of engagement invited input on:

1. The draft engagement plan, electricity demand forecast and early identified needs to set the foundation of this planning work.
2. The defined electricity needs for the region and high level screening of potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

The first Webinar centered around presenting the draft demand forecast as well as preliminary issues identified in the region. Input was requested on major electricity demand projects that may not have been captured in the forecast as well as any ideas about the development of the engagement plan. The second Webinar presented a completed forecast, list of issues, as well as a slate of wires and non-wires alternatives options for each issue. At this point the public was asked to provide input on the options to help shape the recommendations. The final Webinar presented the recommendations found in Section 7 and feedback on the final outcome was requested.

One-on-one outreach to communities, and stakeholders, including the largest electricity customers, located where stations that were over or close to their Long-Term Rating was influential in informing updates to the long-term forecast and ultimately to the report recommendations. Discussions addressed long-term energy plans as electricity customers' expansion and/or decommissioning plans.

Comments received during this engagement were primarily focused on ensuring that the growth plans of communities and large electricity users have been considered and accounted for in the IRRP work as well as the type of solutions addressing those needs. Feedback received during the written comment periods for these webinars helped to guide further discussion throughout the development of this IRRP as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to Renfrew Region subscribers, municipalities and communities as well as to the members of the East Ontario Regional Electricity Network.

Based on the discussions through the Renfrew IRRP engagement initiative, a key priority is to ensure that the IRRP and recommended actions align with the accelerated demand for housing in the region as well as can prepare to accommodate potential large scale increase in electricity needs by two large customers in the area. These insights have been valuable to the IESO in understanding how the region is growing to ensure an accurate electricity demand forecast, determination of needs and recommendation of solutions to ensure the adequacy and reliability of supply over the long-term.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Renfrew Region IRRP engagement webpage.

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on local planning and development activities related to electricity to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings with the upper- and lower-tier municipalities in the region were held to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; and, other opportunities for broader community engagement. These meetings helped to inform the municipal/community electricity needs and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

Through these discussions valuable feedback was received around anticipated growth in specific municipalities in the region. New insights on notable residential growth, in particular in exurban areas, was identified through discussions with the Town of Petawawa, City of Pembroke, Town of Laurentian Valley, and the Town of Deep River, which is reflected in the demand forecast and associated IRRP recommendations.

8.5 Engaging with Indigenous Communities

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning across Ontario. To raise awareness about the regional planning cycle in Renfrew, the IESO invited Indigenous communities located in or near the Renfrew region to participate in webinars that were held on July 21, 2021, February 9, 2022 and November 1, 2022. These communities included: Alderville, Algonquins of Ontario (AOO Consultation Office), Algonquins of Pikwakanagan, Curve Lake, Hiawatha, Mississaugas of Scugog Island, the Metis Nation of Ontario Ottawa Region Metis Council, and the Metis Nation of Ontario High Land Waters Metis Council. The Huron-Wendat Nation, now located in Wendake, Quebec, was also invited due to their historical presence in southern Ontario and their interest in archaeological resources. The IESO also invited the Haudenosaunee Chiefs Confederacy Council to the July and November 2022 webinars upon being informed of their interest in Renfrew.

Indigenous Participation and Engagement in Transmission Development

By conducting regional planning, the IESO determines the most reliable and cost-effective option after it has engaged with stakeholders and Indigenous communities, and publishes those recommendations in the applicable regional or bulk planning report. Where the IESO determines that the lead time required to implement those solutions require immediate action, the IESO may provide those recommendations ahead of the publication of a planning report, such as through a hand-off letter to the lead local transmitter in the region, for example.

As part of the overall transmission development process, a proponent applies for applicable regulatory approvals, including an Environmental Assessment that is overseen by the Ministry of Environment, Conservation and Parks (MECP). This process includes, where applicable, consultation regarding Aboriginal and treaty rights, with any approval including steps to avoid or mitigate impacts

to said rights. MECP oversees the consultation process generally but may delegate the procedural aspects of consultation to the proponent. Following development work, the proponent will then need to apply to the OEB for approval through a Leave to Construct hearing, and only if approval is granted, can it proceed with the project. In consultation with MECP, project proponents are encouraged to engage with Indigenous communities on ways to enable participation in these projects.

9. Conclusion

The Renfrew IRRP identifies electricity needs in the region over the 20-year period from 2022 to 2042, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. The IESO will continue to participate in the Technical Working Group during the next phase of regional planning, the RIP, to provide input and ensure a coordinated approach.

In the near term, the IRRP recommends a load transfer from Forest Lea DS to Craig DS on the order of 2 MW. Further, it is recommended to build a new HVDS near Petawawa DS to help meet both the near term expected expansion work as well support future anticipated larger scale fuel-switching initiatives. Lastly, it is recommended that further analysis is conducted during the RIP period to choose between building a new HVDS or new TS in the city of Pembroke in order to select the most prudent investment. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

In the long term, the IRRP recommends that the Technical Working Group continues to monitor the development of the two large scale energy projects that have been identified in the region. The size and timing of the projects will determine when and where further action will need to be taken. Installing a capacitor will likely be sufficient to accommodate one of the two scenarios but both will require a more robust solution which will be developed by the Technical Working Group.

The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.

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Connecting Today.
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Renfrew

REGIONAL INFRASTRUCTURE PLAN

July 13, 2023

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Distribution)
Ottawa River Power Corporation (ORPC)

Disclaimer

This Regional Infrastructure Plan (RIP) Report for Renfrew region was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Technical Working Group (TWG).

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Technical Working Group.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Regional Infrastructure Plan Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Regional Infrastructure Plan Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE TECHNICAL WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE RENFREW REGION.

The participants of the Renfrew Regional Infrastructure Plan ("RIP") Technical Working Group ("TWG") included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Ottawa River Power Corporation (ORPC)

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process. Hydro One, as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region and publishes a RIP report. The second cycle of the Regional Planning process for the Renfrew region was initiated with Needs Assessment (NA) and the report was published in May 2021 by Hydro One. This was followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) which were published in August 2021 and December 2022, respectively, by the Independent Electricity System Operator (IESO).

The Renfrew RIP provides a consolidated summary of needs and recommended plans for the region over a study period of 2022-2042 based on available information. In this regional planning cycle, plans are recommended for the near to medium-term needs. The needs for the longer term were assessed but due to uncertainties in the load growth, long-term needs will be monitored and further reviewed in next regional planning cycle.

I. Following Major projects were completed during the last ten years:

- Chenaux TS: 230/115 kV, T3 & T4 Autotransformers replaced with new 75/100/125 MVA units along with regulators TR3 and TR4, 115kV oil circuit breakers 4X6 and 4X2Y, completed in 2021.

II. Following Major projects are underway:

- 115kV D6 Circuit: Complete line refurbishment of 76.8 km Line section between Des Joachims TS and Petawawa/Craig DS, planned in-service date in 2025.

III. New needs identified during the second cycle regional planning:

a. Asset Renewal for Major HV Transmission Equipment

- No new major HV Transmission Asset renewal identified.

b. Station Capacity

- Pembroke TS: Currently exceeding summer station LTR.
- Forest Lea DS: Currently exceeding summer station LTR.
- Petawawa DS: Update on need as identified in IRRP.

c. Transmission Line Capacity

- No new Transmission Line capacity identified.

d. System Reliability, Operation and Load restoration

- No System Reliability, Operation and Load restoration issues identified.

e. Long term needs

- Des Joachims sub-system supply capacity: Monitor load growth in the area.

The major infrastructure investments in this second cycle recommended by the TWG in the Renfrew Region over the near, medium and long-term period are given in Table 1 below, along with their planned in-service date and estimate for planning purposes.

Table 1. Renfrew Region - Recommended Plans over the 2022-2042 Study Period

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Station capacity needs				
Pembroke TS	Hydro One Dx and ORPC to continue to explore both the new TS and HVDS options and determine most feasible solution	Hydro One Tx	2028	14-30
Forest Lea DS	Transfer 2 MW load to Craig TS	Hydro One Dx	2026	0.05
Petawawa DS	No longer needed as Load Forecast is revised.	Hydro One Dx	-	-
Long-term Supply capacity needs				
Des Joachims sub-system	Monitor load growth in the area and wait for confirmation of investments.	IESO	-	-

Note:
a) The planned in-service dates are tentative and subject to change.
b) Costs are based on planning estimates may exclude the cost for distribution infrastructure (if required)

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE RENFREW REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Technical Working Group ("TWG") in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The TWG included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Ottawa River Power Corporation (ORPC)

The Renfrew region is located in Eastern Ontario with the majority of load along the Ottawa river. For electrical planning purposes this region includes eighteen municipalities including the towns of Arnprior, Deep River, Laurentian Hills, Petawawa and Renfrew. As well as the townships of Admaston/Bromley, Bonnechere Valley, Brudenell, Lyndoch and Raglan, Greater Madawaska, Head, Clara and Maria, Horton, Killaloe, Hagarty and Richards, Laurentian Valley, Madawaska Valley, McNab/Braeside, North Algona Wilberforce and Whitewater Region; as well as the City of Pembroke. Figure 1-1 represents the Renfrew Region Map.

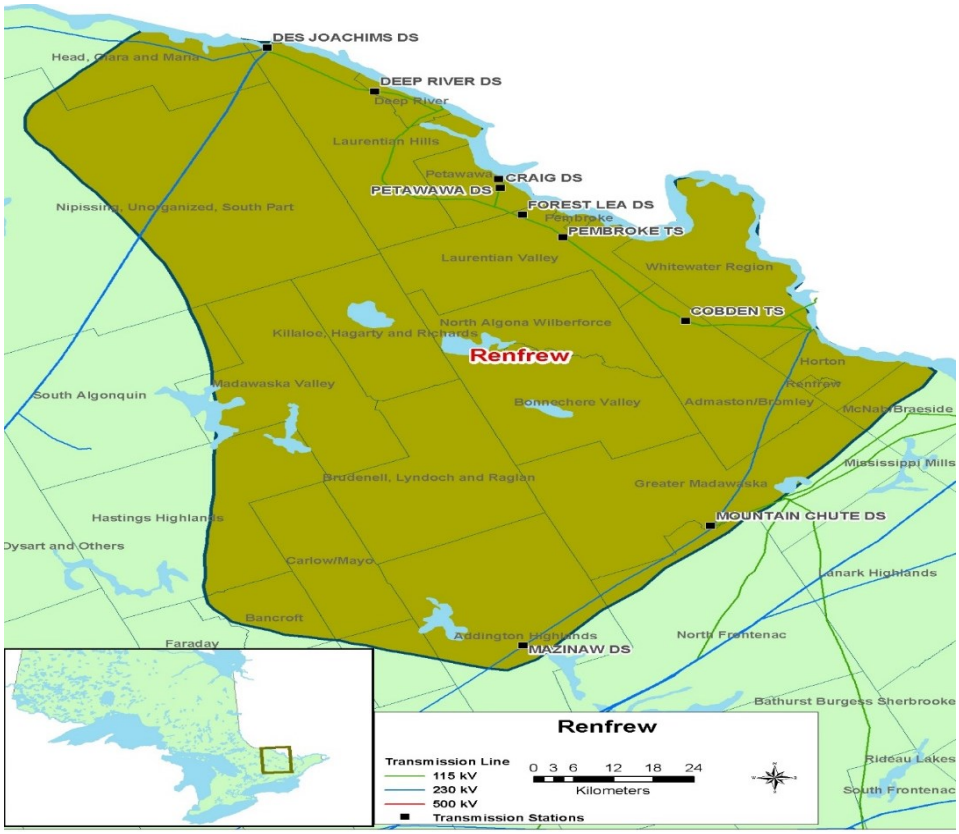


Figure 1-1 Renfrew Region Map

1.1 Objectives and Scope

This RIP report examines the needs in the Renfrew Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs for the region;
- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan).
- Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, asset renewal for major high voltage transmission equipment, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near, and medium-term needs identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the study period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the Renfrew IRRP or identified by the TWG.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the results of the adequacy assessment of the transmission facilities in the region over the study period and identifies the needs.
- Section 7 discusses the needs, provides alternatives to address each need, and recommends a preferred solutions; and,
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: The Needs Assessment ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Technical Working Group (TWG) assess, and document which of the needs that,

a. can be addressed directly between the customer and transmitter along with a recommended plan, and;
b. require further regional coordination and identification of LDCs to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the TWG as to whether further regional coordination is necessary to address some or all the regional needs. If no, further regional coordination is required, recommendation to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The Region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs,

a. are local in nature,
b. require limited investments in wires (transmission or distribution) solutions, and;
c. do not require upstream transmission investments.

In situations where identified needs require further coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the TWG, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and decides on the most appropriate regional planning approach. The approach is either a RIP,

which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region were identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders and establishes a Local Advisory Committee (LAC) in the region or sub-region.
The RIP phase is the final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the regional planning process taking effect.
- The NA, SA, IRRP and LP phases of regional planning.
- Conducting wires planning as part of the RIP for the region or sub-region.
- Planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2 -1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

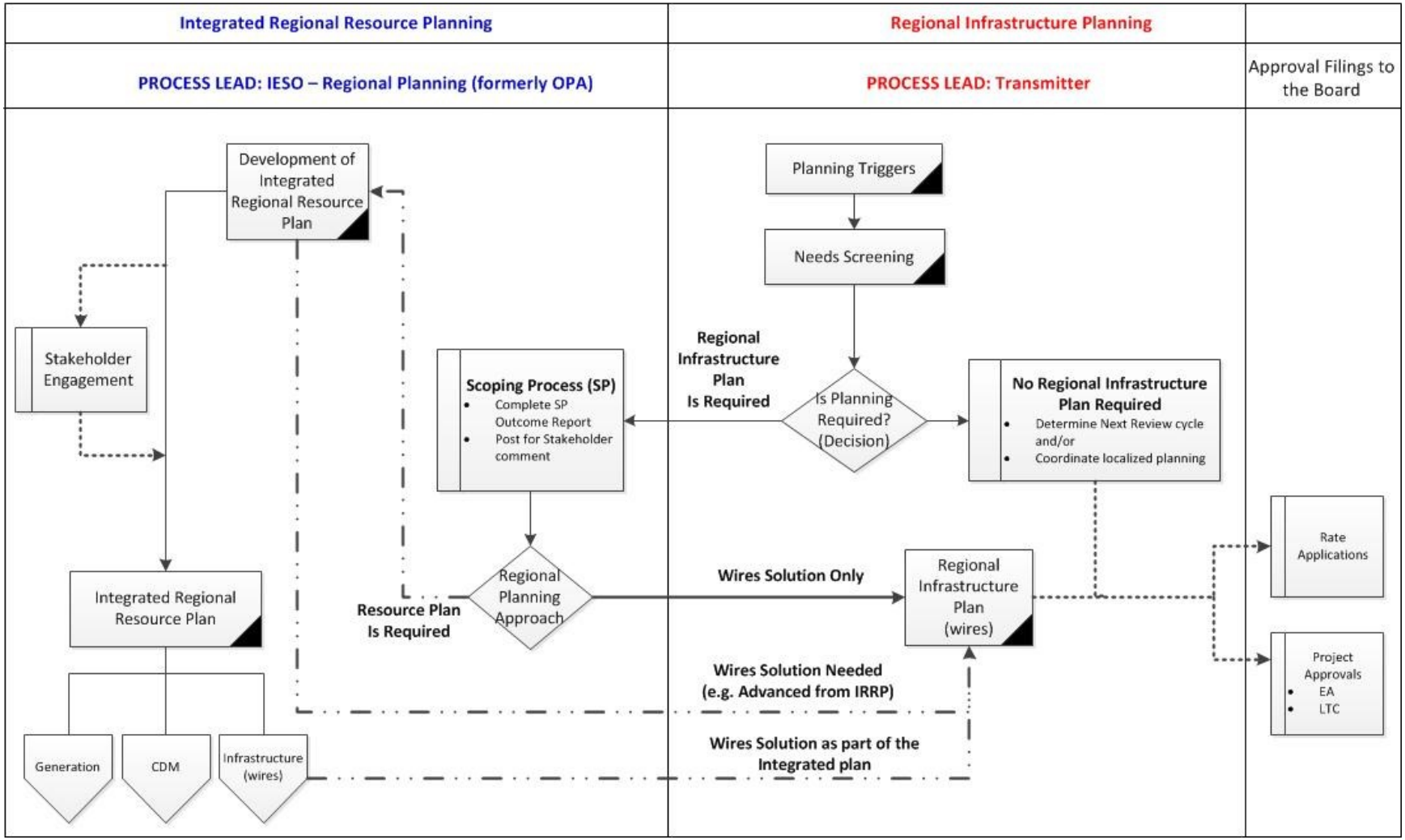


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four-step process (see **Error! Reference source not found.**) as follows:

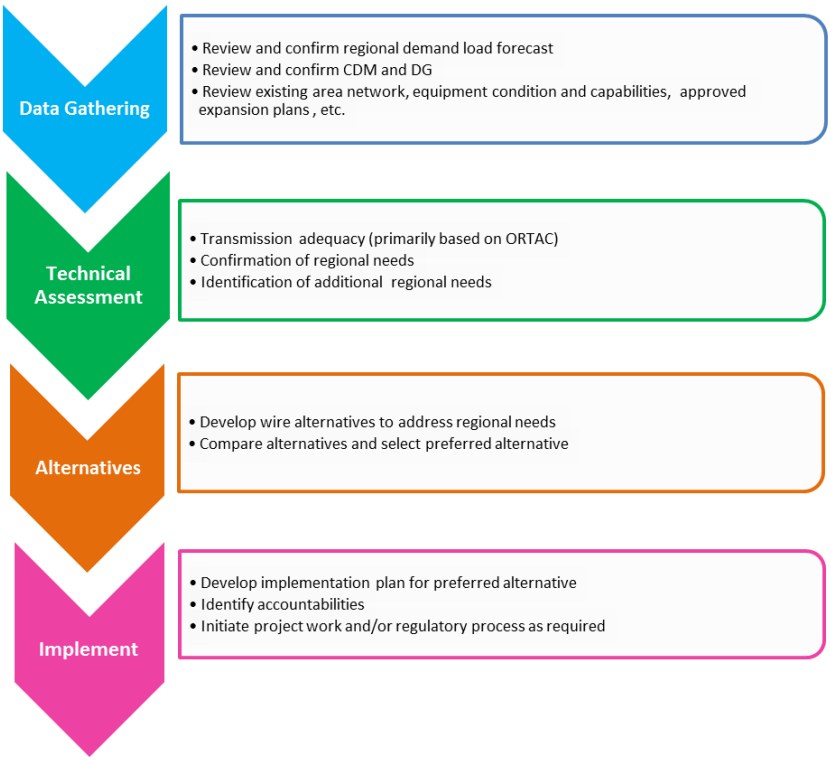


Figure 2-2 RIP Methodology

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) to reconfirm or update the information as required. The data collected includes:

    - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was adopted for this RIP, with the exception of Petawawa DS.
    - Review and confirm electrification, other growth scenarios, etc. which effects the projects recommended in in previous stages.
    - Existing area network and capabilities including any bulk system power flow assumptions.
    - Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and medium-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiate project work or obtain permissions from Regulatory Commission if any.

3. REGIONAL CHARACTERISTICS

THE RENFREW REGION IS LOCATED IN EASTERN ONTARIO WITH THE MAJORITY OF LOAD ALONG THE OTTAWA RIVER. THE ELECTRICITY SUPPLY TO THE REGION IS PROVIDED THROUGH ONE 230KV CIRCUIT X1P AND THREE 115 KV RADIAL CIRCUITS: D6, X6 AND X2Y. THE 115KV CIRCUITS ARE SUPPLIED BY 230/115 KV AUTOTRANSFORMERS AT CHENAUX TRANSFORMER STATION (TS) FROM THE EAST AND DES JOACHIMS TS FROM THE WEST. A NORMALLY OPENED 115KV SWITCH AT PEMBROKE TS ISOLATES THE EAST AND THE WEST SIDES OF THE REGION.

The Renfrew region is bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the South. The distribution system in this region consists of voltage levels 44 kV and 12.5 kV. The main generation facilities in the Renfrew region are Chenaux Generation Station (GS) of 143.7 MW, Mountain Chute GS of 170.2 MW and Des Joachims GS of 432.5 MW

Hydro One Networks Inc. (Distribution) is the main LDC in the area. Other LDCs supplied from electrical facilities in the Renfrew region include Ottawa River Power Corporation and Renfrew Hydro Inc., both are embedded into Hydro One's distribution system. Renfrew Hydro Inc. customers are being fed from Stewartville TS which is part of the Greater Ottawa Regional Planning. As such, Renfrew Hydro Inc. has not been included as part of this NA.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3-1.

- Chenaux TS is a major 230kV station in the region. The station has 143.7MW of hydraulic generation connected to the 230kV bus. The station connects to the bulk system via a single 230kV circuit X1P. Two autotransformers step down the voltage to 115kV to supply two radial circuits X6 and X2Y
- The 115kV circuits X6 and X2Y from Chenaux TS supply four stations: Pembroke TS, Cobden TS, Cobden DS and Customer Transformer Station (CTS-1).
- Des Joachim TS is the other major 230kV transformer station in the Region. There are 432.5MW of hydraulic generation connecting to the 230kV bus. The station interconnects to the Bulk Electric System (BES) via five 230kV circuits which are not in the scope of this regional assessment. Two autotransformers (one operates as standby) step down the voltage to 115kV to supply one radial circuit D6.
- The 115kV circuit D6 from Des Joachim TS 115kV bus supplies six stations: Des Joachims Distribution Station (DS), Deep River DS, Craig DS, Forest Lea DS, Petawawa DS, and Customer Transformer Station (CTS-2)
- Bryson GS from Hydro Quebec can be radially connected to Renfrew region via X2Y, when required.
- The 230kV single circuit X1P from Dobbin TS to Chenaux TS connects two stations in Renfrew region: Mountain Chute GS (with hydraulic generation of 170.2MW) and Mazinaw DS.

- Mountain Chute DS, a 115kV station adjacent to Mountain Chute GS, is supplied by a circuit W3B from outside of the studied region.

The circuits and stations of the area are summarized in the Table 2-1 below:

Table 1-1: Transformer Station and Circuits in the Renfrew region

115kV circuits	230kV circuits	Transformer Stations	Generation Stations
D6, X6 and X2Y	X1P	Des Joachims TS*, Des Joachims DS, CTS-1, Deep River DS, Chalk Craig DS, Petawawa DS, Forest Lea DS, Pembroke TS, Cobden TS, Cobden DS, CTS-2, Chenaux TS*, Mountain Chute DS and Mazinaw DS.	Mountain Chute GS (170.2MW) Des Joachims GS (432.5MW) Chenaux GS (143.7MW)

*Stations with Autotransformers installed

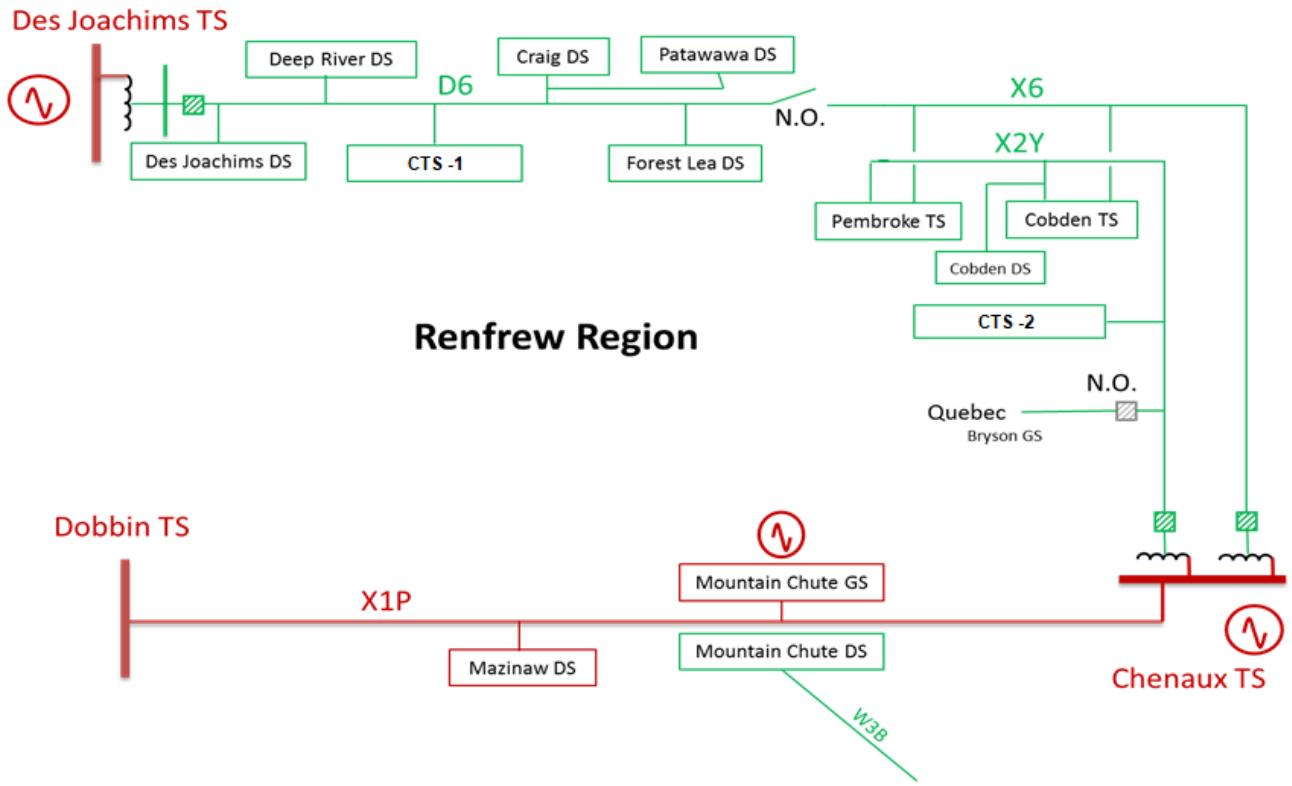


Figure 3-1 Renfrew Region Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR UNDERWAY

OVER THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE CURRENTLY UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE RENFREW REGION.

A list of all the projects that are completed in past ten years or are currently underway is provided and are briefly discussed in the sub-sections. As a part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the Renfrew region to improve the supply capability and reliability.

Hydro One, being the only Transmission Asset Owner(TAO) in the region, has undertaken the execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. Following Major projects were completed during the last ten years:

1. Chenaux TS Autotransformer Replacement (2021): The 230/115 kV T3/T4 Autotransformers were replaced by new 75/100/125 MVA units along with associated facilities.

II. Following Major projects are underway:

1. 115kV D6 Line refurbishment (2025): This project is currently underway and includes complete refurbishment of 76.8km line between Des Joachims TS and Petawawa/Craig DS due to its condition assessment.

Note: The planned in-service year for the above projects is tentative and is subject to change.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The TWG adopted the IRRP load forecasts for this RIP as no material change was identified, with the exception of Petawawa DS. At Petawawa DS, the load increased abnormally in June 2020 due to generator refurbishment work at a customer facility connected to Petawawa DS which resulted in adding about 3.1 MW to station peak. The load returned to its normal value after the work was completed in July 2020. The updated load forecast for Petawawa DS considers the updated actual peak load recorded in 2021.

The TWG participants, including representatives from LDC's, IESO and Hydro One provided information and input for the IRRP Load forecast. The municipalities were contacted as part of IRRP stakeholder engagement process to get their insight on the future load growth and was considered during IRRP load forecast development. During the study period, the load in the Renfrew region is expected to grow at an average annual rate of approximately 1.5% in summer from 2022 to 2042. The assessment is based on both summer and winter peak loads.

Figure-5-1 & 5-2 shows the Renfrew region extreme summer & winter weather non-coincident load forecast from 2022 to 2042. The load forecast from the Renfrew region IRRP was adopted as agreed to by the TWG, except for Petawawa DS. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.

Non-coincident forecast for the individual stations in the region is available in Appendix E and is used to determine any need for station capacity relief in the region.

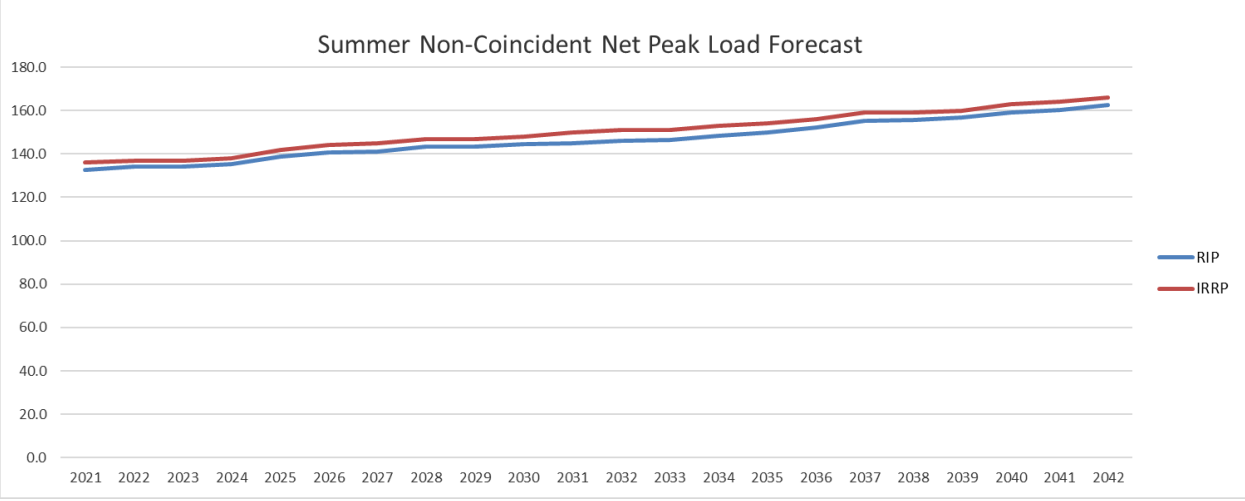


Figure 5-1 Renfrew Region Non–Coincident Net Summer Peak Load Forecast

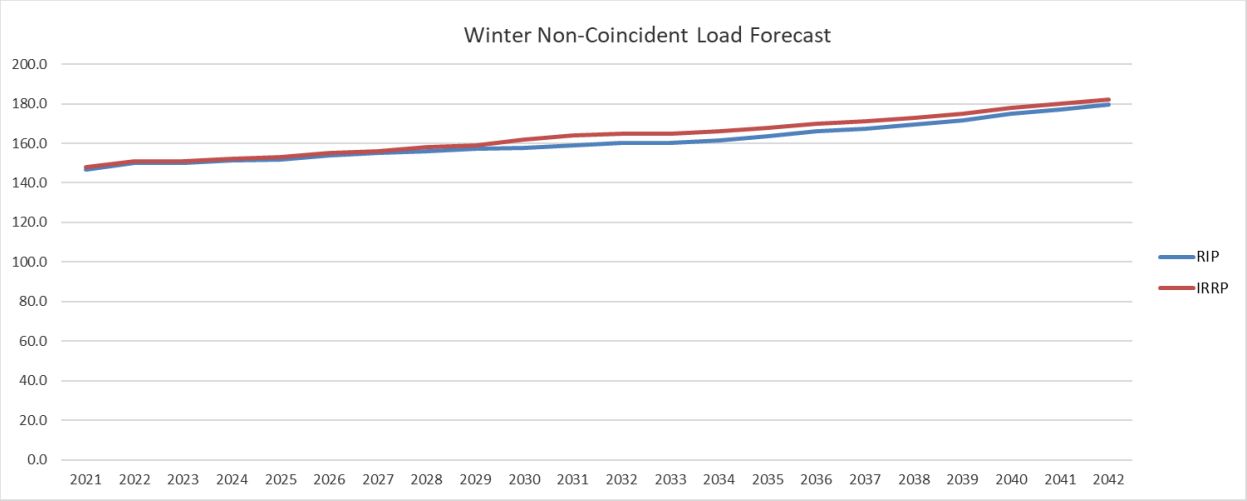


Figure 5-2 Renfrew Region Non–Coincident Net Winter Peak Load Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2022-2042.
- LDCs reconfirmed load forecasts up to 2042 in the area are the same as the IRRP(except for Petawawa DS).
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is summer peaking, so this assessment is based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) based on 35°C ambient temperature.
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE RENFREW REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

In current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- Renfrew region Second cycle Needs Assessment Report, Completed in May 2021 by Hydro One
- Renfrew region Second cycle Scoping Assessment Report, Completed in August 2021 by the IESO
- Renfrew region Second cycle Integrated Regional Resource Plan Report, Completed in December 2022 by the IESO

The NA and IRRP reports identified several regional needs based on the forecasted load demand over the near, mid and long-term period. A detailed description and status of plans to meet these needs is given in Section 7.

This section provides a review of the adequacy of the transmission lines and stations in the Renfrew Region. The adequacy is assessed using the load forecasts provided in Appendices D. The assessment assumes all projects currently underway (described in section 4) are in-service.

Sections 6.1- 6.5 present the results of the adequacy assessment and Table 6-1 lists the region's near, mid, and long-term needs identified in both the IRRP and RIP phases.

6.1 Station Capacity Needs

Over the study period 2022-2042 RIP reviewed the capacity of all the 230kV and 115kV Transformer Stations within the Renfrew region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 6-1 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 6-1 Renfrew Region – Station capacity needs

Sr.no.	Station Name	Station LTR (MW) (Summer/Winter)	2022 Loading (MW) (Summer/Winter)	Need Date
1	Pembroke TS	47/57 MW	48/53 MW	Current
2	Forest Lea DS	8.6/11.6 MW	9/11 MW	Current
3	Petawawa DS	16.3/20.2 MW	10/10 MW	*

* Identified during IRRP phase but was eliminated in RIP following the load forecast update for Petawawa DS.

The options and preferred solutions to address these needs are discussed further in Section 7 of the report.

6.2 Transmission Line Capacity Needs

Over the study period 2022-2042 RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Renfrew region. It was determined that all Transmission Lines are within the thermal limits of the circuits and within the voltage range as per ORTAC over the study period adequate over the study period for the loss of a single 230/115 kV circuit in the Region.

6.3 Asset Renewal for Major HV Transmission Equipment

Hydro One is the only Transmission Asset Owner (TAO) in the Renfrew region. Hydro One facilities in the region that will require replacement over the near-medium -term period as listed in Table 6-2 below.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers.
- 230 and 115kV breakers where:
  - replacement of six breakers or more than 50% of station breakers, the lesser of the two
- 230 and 115kV transmission lines requiring refurbishment where:
  - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230 and 115kV underground cable requiring replacement where:
  - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

Table 6-2 Renfrew Region - Planned Replacement Work

Station/Circuit	Need Description	Planned ISD
D6	Complete 76.8kM line refurbishment between Des Joachims TS and Petawawa/Craig DS	2025

*The planned in-service dates are tentative and subject to change.

6.4 Load Security and Load Restoration

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

This RIP further confirms there are no identified load security and restoration violations within the study period. The technical working group does not recommend any further action.

6.5 Long Term Needs

During IRRP phase, a long-term supply capacity issue has been identified under high growth scenarios in the Des Joachims sub-system. The Des Joachims sub-system refers to transmission line D6 connected to the Des Joachims TS in the west of Renfrew region.
The options and preferred solution to address this need is discussed further in Section 7 of the report.

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility.

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE PREFERRED WIRES SOLUTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE RENFREW REGION.

The electrical infrastructure needs for the Renfrew Region are summarized in Table 7-1. These needs include those previously identified in the NA and IRRP for the Renfrew region. All estimated costs included in the alternative analysis are considered as planning estimates and are used for comparative purposes only.

Table 7-1 Renfrew Region – Near, Medium- and Long-Term Needs

Station/Circuit Name	Description of Need	Need Date	RIP Report Section
Station Capacity Needs			
Pembroke TS	Station has exceeded its summer LTR	Current	7.1.1
Forest Lea DS	Station has exceeded its summer LTR	Current	7.1.2
Petawawa DS	Station was expected to exceed its summer LTR	*	7.1.3
Long Term Needs			
Des Joachims sub-system	Supply capacity issue in long-term under high growth scenario	2034	7.5.1

* Identified during IRRP phase but was eliminated in RIP following the load forecast update.

7.1 Station Capacity Needs

A station capacity assessment was performed over the study period 2022-2042 for the 230kV and 115kV transforming stations in the Renfrew region using either the summer or winter peak load forecasts that were provided by the study team. Based on the results, the following station capacity needs have been identified in the during the study period:

7.1.1 Pembroke TS – 115kV

Pembroke TS supplies Hydro One Dx while ORPC is an embedded LDC. It is a 115/44 kV Transmission Station (TS) with two 25/33/42 MVA (T1/T2) transformers supplied by circuits X2Y & X6 with a summer and winter LTR of 47 MW and 57 MW, respectively.

Pembroke TS has three distribution feeders which supplies Hydro One Distribution, with ORPC as an embedded LDC on two feeders. This station has exceeded its normal supply capacity in 2019 and TWG has agreed that a wires solution is required to address this need.

The following alternatives were considered to address the need:

Alternative 1 - Maintain Status Quo:
This solution is not recommended as it does not address the supply capacity need at the station and will prevent future load growth at this station.

Alternative 2 – Build a new HVDS:
A new HVDS would be built near Pembroke TS. An HVDS would provide 18 MW of capacity at an approximate cost of $14M, which includes $11M for building the station and at a least an additional $3M for distribution costs. The new HVDS would be connected to 115kV circuit X6 as during contingency it is less limiting than X2Y as the overall circuit have a higher thermal rating compared to X2Y. The Pembroke DS load, which is expected to be 6 MW, will be transferred to the new HVDS, therefore freeing up capacity for new load on Pembroke TS. The remaining capacity of new HVDS would also be able to supply an additional 12MW of new load at 12kV in the area. Although connecting a HVDS to one circuit is less reliable than a TS connected to both circuits as it does not provide full redundant supply, there is an existing transmission 115kV switch at Cobden TS that can be used to tie X2Y and X6 to restore the load on the new HVDS for in case of a fault East of Cobden TS. All of ORPC load is currently supplied by the existing two 44kV feeders from Pembroke TS. Due to the current distribution configuration of the ORPC system, future ORPC load from the new HVDS will require further modifications at ORPC's operating system within its service territory.

From a capacity standpoint, this option would be able to supply all the forecasted load in area for the long term.

Alternative 3 – Build a new Transmission Station (TS):
Build a new TS consisting of two 115/44 kV 25/33/42 MVA step-down transformers near the existing Pembroke TS, connected to both the X2Y and X6 circuits. This would cost approximately $30M. The new supply station will be able to supply 47 MW, which is more than sufficient for the 20-year load forecast, including Pembroke TS long term growth. Similar to the HVDS option, 115kV circuit X2Y is more limiting and during a contingency situation, the thermally limiting sections on X2Y will prevent the new TS from supplying the full 47 MW station capacity.

Recommendation:
Both alternatives 2 and 3 addresses the need for additional capacity at Pembroke TS during normal operations. However, building a new TS is significantly more expensive than building a new HVDS and will also require an additional cost for transmission line upgrades to utilize the full station capacity. Building a new HVDS which is a less costly alternative, has its own operational limitations and complications for ORPC. As the assessment of both alternatives are very complex, further discussion between Hydro One Tx and the impacted LDCs is required. Both Hydro One Dx and ORPC will continue to explore these two options to determine the most feasible solution to address the capacity need at Pembroke TS.

7.1.2 Forest Lea DS – 115kV

Forest Lea DS is located in Laurentian Valley Hills, outside the city of Pembroke. It is connected at the tail end of the circuit D6, after Petawawa DS and Craig DS. This station is owned and operated by Hydro One Dx. Forest Lea DS is a 115/13.4 kV Step down station and is radially supplied by circuit D6 it has two 7.5/11 MVA (T1/T2) transformers with a summer LTR of 8.6 MW and winter LTR of 11.1 MW.

This station has already exceeded its normal supply capacity but will only increase by slightly over the station LTR at the end of the study period. The TWG has agreed that a solution is required to address this need.
The following alternatives were considered to address the need:

Alternative 1 - Maintain Status Quo:
This solution is not recommended as it does not address the supply capacity need at the station and will prevent future load growth at this station.

Alternative 2 – Load Transfer:
Through existing Dx interties, there is a possibility of transferring load to the Pembroke DS and Craig DS. TWG confirmed that a 1 MW load transfer to Craig DS can be done with minimal work with a capital cost of only $50k. A transfer to Pembroke DS, is also technically feasible, but would result in a further overload of the upstream Pembroke TS and the outcome of the preferred solution for Pembroke TS station capacity issue could affect the load transfer. In light of all these reasons, load transfer at Craig DS is preferred.

Alternative 3 – Upgrading the supply capacity:
The capacity of Forest Lea station can be upgraded using two methods which are:
i) Upgrading the transformers to add 10 MW of capacity for a capital cost of $4.5M or,
ii) Installing fan cooling and SCADA monitoring system to the existing transformers to add 4 MW at a capital cost of $0.6M.

Alternative 4 – Building new HVDS:
It is also possible to build a new HVDS for the Forest Lea area which will add 18 MW of load at a capital cost of $12M. This option will provide a higher capacity, which is not required at this moment, even under consideration of a high growth scenario.

Recommendation:
The need of station capacity at Forest Lea DS is current, but the expected load growth is very low. The load at this station is only expected to grow to slightly over 1 MW in the long-term. Hence, load transfer to Craig TS is considered as the most appropriate as well as cost effective alternative. TWG recommends and agrees to transfer 2 MW load to Craig DS. The expected completion date for this load transfer is 2026.

7.1.3 Petawawa DS – 115kV

Petawawa DS supplies the town of Petawawa and a large customer. The majority of the load i.e., 80% of the total load, is consumed by this large customer. The station is radially supplied by D6 and is located at the end of the circuit, right after Craig DS. It has two 115/13.4 kV Step down 7.5/10/13 MVA (T1/T2) transformers with a summer LTR of about 16 MW and winter LTR of 20 MW.

As per the IRRP Load Forecast the station reaches its summer LTR in 2030 and hence recommended to build a new HVDS transformer station at Petawawa with in-service date of 2027. During the RIP phase it was observed that the load increased abnormally in June 2020 due to generator refurbishment work at the customer's facility in Petawawa DS and resulted in the net load increase by 3 MW at the station. This work was completed in July 2020. As the load displacement generation is permanently operating, the net load at the station returned to its normal value resulting in a net load of approximately 9.8 MW during the year 2021. Hence, the Load Forecast for

Petawawa DS was updated in the RIP, and the 2022 load was determined by considering the actual load in 2021. The updated load forecast yields a lower Net Load at the end of study period.

Recommendation:
Since the elevated load forecast was updated for actual value, the load at Petawawa DS remains below the summer/winter (16.3/20.2 MW) LTRs for the long-term forecast. However, during the IRRP phase the customers in this area have indicated some possible future expansion and heating load conversion under Canadian Net-Zero Emissions Accountability Act that was considered in a high load growth scenario. Hence, for now it is recommended to defer this need as no additional capacity is required at this station for the short to medium term, but the TWG will continue to monitor the future high load growth scenario and trigger regional planning earlier if and when demand arises at the station.

7.2 Transmission Line Capacity Needs

All line and equipment load shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2022-2042 for the 230kV and 115kV Transmission line circuits in the Renfrew region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, no new Transmission line capacity needs were identified in the region during the study period.

7.3 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for "right sizing" the equipment:

- Maintaining the status quo;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities;
- Eliminating equipment by transferring all the load to other existing facilities;
- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
- Replacing equipment with higher ratings and built to current standards.

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.
No new major HV Asset Renewal Needs were identified in the region during the study period.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2022-2042 to cater

this need**.** Based on the results, no new significant system reliability, operating and restoring issues have been identified for this Region.

7.5 Long Term Considerations

7.5.1 Des Joachims sub-system – Supply capacity issue

The Des Joachims sub-system refers to transmission line D6 connected to the Des Joachims TS in the west of Renfrew region and ends at Petawawa DS and Forest Lea DS in the east. During IRRP, two high growth scenarios (i.e., increase in load by 20MW & 40MW) were identified as a part of the engagement process for the Des Joachims sub-system. The LMC of Des Joachims sub-system is approximately 80MW and under high growth scenarios, with one element out and a contingency to a generator at Des Joachims TS, under peak coincident demand and low generation conditions, voltage change violations are identified at the stations connected to the end of D6 circuit.

Alternative 1 - Maintain Status Quo:
The need is identified in the medium to long-term, and both high load growth scenarios have fair amount of uncertainties. Monitor the current load growth in the area and maintain status quo until next regional planning cycle.

Alternative 2 – Capacitor banks:
Installing capacitor banks at either Craig DS, Petawawa DS or Forest Lea DS will improve the LMC by approximately 10 MW and can support the first high growth scenario i.e., a load growth of over 20 MW.

Alternative 2 – Transmission options:
For the more aggressive load growth scenario, i.e., load growth of over 40MW, the support provided by capacitor banks will not be enough and there will be a need to construct new transmission line in the area.

Recommendation:
The need is identified in the mid to long-term, and in light of uncertainties of the load growth in the sub-system. Hence, for now it is recommended that TWG will continue to monitor the future high load growth scenario and if required can proceed with the capacitor upgrade if and when need arises.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE RENFREW REGION.

The major infrastructure investments recommended by the Technical Working Group (TWG) in the near, medium and long-term are provided in Table 8-1 below, along with their planned in-service dates and estimates for planning purposes.

Table 8-1 Recommended Plans in Region over the 2022-2042 Study Period

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Station capacity needs				
Pembroke TS	Hydro One Dx and ORPC to continue to explore both the new TS and HVDS options and determine most feasible solution	Hydro One Tx	2028	14-30
Forest Lea DS	Transfer 2 MW load to Craig TS	Hydro One Dx	2026	0.05
Petawawa DS	No longer needed as Load Forecast is revised.	Hydro One Dx	-	-
Long-term Supply capacity needs				
Des Joachims sub-system	Monitor load growth in the area and wait for confirmation of investments.	IESO	-	-

Note:
a) The planned in-service dates are tentative and subject to change.
b) Costs are based on planning estimates may exclude the cost for distribution infrastructure (if required)

9. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. December 18, 2018)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. October 1, 2022)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[5] Independent Electricity System Operator, Renfrew region IRRP Cycle-2 (December, 2022)

[6] Independent Electricity System Operator, Renfrew region Scoping Assessment Cycle-2 (August, 2021)

[7] Hydro One Networks Inc., Renfrew region Needs Assessment Cycle-2 (May 2021)

APPENDIX A. RENFREW REGION - STATIONS

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1.	Cobden DS (T3)	115/12.5	X2Y
2.	Cobden TS (T1/T2)	115/44	X2Y/X6
3.	Craig DS (T1/T2)	115/12.5	D6
4.	Deep River DS (T1/T2/T3)	115/12.5	D6
5.	Des Joachims DS (T1)	115/12.5	D6
6.	Forest Lea DS (T1/T2)	115/12.5	D6
7.	Mazinaw DS (T1/T2)	230/12.5	X1P
9.	Pembroke TS (T1/T2)	115/44	X2Y/X6
10.	Petawawa DS (T1/T2)	115/12.5	D6

APPENDIX B. RENFREW REGION - TRANSMISSION LINES

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Des Joachims DS to Pembroke TS	D6	115
2	Chenaux TS to Pembroke TS	X6	115
3	Chenaux TS to Pembroke TS	X2Y	115
4	Dobbin TS to Chenaux TS	X1P	230

APPENDIX C. RENFREW REGION - DISTRIBUTORS

Sr. no.	Name of LDC
1	Hydro One Networks Inc.(Distribution)
2	Ottawa River Power Corporation (ORPC)

APPENDIX D. RENFREW REGION - MUNICIPALITIES

Sr. no.	Name of Municipality
1	Town of Arnprior
2	Town of Deep River
3	Town of Laurentian Hills
4	Town of Petawawa and Renfrew
5	Township of Admaston/Bromley
6	Township of Bonnechere Valley
7	Township of Brudenell
8	Township of Lyndoch and Raglan
9	Township of Greater Madawaska
10	Township of Head
11	Township of Clara and Maria Horton
12	Township of Killaloe
13	Township of Hagarty and Richards
14	Township of Laurentian Valley
15	Township of Madawaska Valley
16	Township of McNab/Braeside
17	Township of North Algona Wilberforce and Whitewater Region
18	City of Pembroke

APPENDIX E. RENFREW REGION - STATIONS LOAD FORECAST

Summer Net Non-Coincident Load Forecast

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
CTS-1	Tx	N/A	N/A	N/A	N/A	Load	7.0	7.0	7.0	7.1	7.1	7.1	7.1	7.2	7.2	7.2	7.2	7.2	7.3	7.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
						Net	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8	8
CTS-2	Tx	N/A	N/A	N/A	N/A	Load	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Cobden DS	Tx	T3	N/A	N/A	9.4	Load	7.1	7.2	7.3	7.3	7.4	7.4	7.5	7.6	7.6	7.7	7.7	7.8	7.8	7.8	7.9	8.9	8.9	8.9	8.9	8.9	8.9
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
						Net	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8
Cobden TS	Tx	T1/T2	N/A	M2 M6	47.8	Load	23.9	24.1	24.3	25.5	25.7	25.9	26.1	26.3	26.4	26.6	26.8	27.0	27.1	27.2	27.3	28.3	28.3	28.3	28.3	28.3	29.3
						DG	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
						CDM	0.4	0.6	0.8	1	1.2	1.4	1.6	1.8	1.9	2.1	2.3	2.5	2.6	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8
						Net	22	22	22	23	23	23	23	23	23	23	23	23	23	23	23	24	24	24	24	24	25
Craig DS	Tx	T1/T2	B1B2	N/A	19.9	Load	14.3	14.4	14.5	15.6	15.7	15.9	16.0	16.1	16.2	16.3	16.4	16.5	17.6	17.6	17.7	17.7	17.7	17.7	18.7	18.7	18.8
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.3	0.4	0.5	0.6	0.7	0.9	1	1.1	1.2	1.3	1.4	1.5	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.8
						Net	14	14	14	15	15	15	15	15	15	15	15	15	16	16	16	16	16	16	17	17	17
Deep River DS	Tx	T1/T2/T3	N/A	N/A	8.6	Load	8.2	8.3	8.3	8.4	9.5	9.5	10.6	10.7	10.7	10.8	10.8	10.9	10.9	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.7	0.7	0.8	0.8	0.9	0.9	1	1	1	1	1	1	1	1
						Net	8	8	8	8	9	9	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Des Joachims DS	Tx	T1	N/A	N/A	9.4	Load	2.0	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
						Net	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Forest Lea DS	Tx	T1/T2	BY	N/A	8.6	Load	9.1	9.2	9.3	9.4	9.4	9.5	9.6	9.7	9.7	9.8	9.9	9.9	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.1
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	1	1	1	1	1	1	1	1	1.1
						Net	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Mazinaw DS	Tx	T1	BY	N/A	6.9	Load	3.1	3.1	3.1	4.1	4.2	4.2	4.2	4.3	4.3	4.3	4.3	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
						Net	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Mountain Chute DS	Tx	T1	BY	N/A	8.6	Load	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pembroke TS	Tx	T1/T2	JQ	M1 M2 M3	47	Load	48.5	48.6	49.9	50.2	51.5	51.7	52.9	53.1	54.5	54.7	55.9	56.1	57.2	58.2	59.3	60.3	60.3	61.3	62.4	63.4	64.4
						DG	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
						CDM	0.3	0.4	0.7	1	1.3	1.5	1.7	1.9	2.3	2.5	2.7	2.9	3	3	3.1	3.1	3.1	3.1	3.2	3.2	3.2
						Net	48	48	49	49	50	50	51	51	52	52	53	53	54	55	56	57	57	58	59	60	61
Petawawa DS	Tx	T1/T2	BY	N/A	16.3	Load	10.5	10.9	11.3	11.6	11.9	12.3	12.6	12.9	13.2	13.6	13.9	14.2	14.4	14.8	15.1	15.3	15.6	15.8	16.2	16.3	16.6
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.5	0.7	0.9	1	1.1	1.3	1.4	1.5	1.6	1.7	1.8	1.9	1.9	2	2.1	2.1	2.1	2.1	2.2	2.1	2.1
						Net	10.0	10.2	10.4	10.6	10.8	11.0	11.2	11.4	11.6	11.9	12.1	12.3	12.5	12.8	13.0	13.2	13.5	13.7	14.0	14.2	14.5

Winter Net Non-Coincident Load Forecast

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
CTS-1	Tx	N/A	N/A	N/A	N/A	Load	9.0	9.0	9.0	9.1	9.1	9.1	9.2	9.2	9.3	9.3	9.3	9.3	9.3	9.3	10.3	10.2	10.2	10.2	10.2	10.2	10.2
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2
						Net	9	9	9	9	9	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10
CTS-2	Tx	N/A	N/A	N/A	N/A	Load	4.0	4.0	4.0	4.0	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Cobden DS	Tx	T3	N/A	N/A	12	Load	7.1	7.1	7.1	7.2	7.2	7.2	7.2	7.3	7.3	7.4	7.4	7.5	7.5	7.5	7.5	7.5	7.5	8.5	8.5	8.5	8.5
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
						Net	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8
Cobden TS	Tx	T1/T2	N/A	M2 M6	54.7	Load	25.4	25.6	25.7	25.8	25.9	26.0	26.1	26.3	26.5	26.6	27.8	27.9	28.0	28.1	28.1	28.1	29.1	29.1	29.1	29.1	30.2
						DG	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
						CDM	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.1	1.3	1.4	1.6	1.7	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2
						Net	25	25	25	25	25	25	25	25	25	25	26	26	26	26	26	26	27	27	27	27	28
Craig DS	Tx	T1/T2	B1B2	N/A	23.2	Load	12.1	12.2	12.2	12.3	13.3	13.4	13.4	13.5	13.6	13.7	13.7	13.8	13.9	14.9	14.9	14.9	14.9	14.9	14.9	15.9	16.0
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1
						Net	12	12	12	12	13	13	13	13	13	13	13	13	13	14	14	14	14	14	14	15	15
Deep River DS	Tx	T1/T2/T3	N/A	N/A	11.6	Load	10.1	10.2	10.2	10.3	11.3	11.4	12.4	12.5	12.5	12.6	12.6	12.7	12.7	12.7	12.8	12.8	12.8	12.8	12.8	12.8	12.8
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
						Net	10	10	10	10	11	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Des Joachims DS	Tx	T1	N/A	N/A	12	Load	**4.0**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.2**	**4.2**	**4.2**	**4.2**	**3.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
						Net	4	4	4	4	4	4	4	4	4	4	4	3	4	4	4	4	4	4	4	4	4
Forest Lea DS	Tx	T1/T2	BY	N/A	11.6	Load	**11.1**	**11.2**	**11.2**	**11.3**	**11.3**	**11.4**	**11.4**	**11.5**	**11.6**	**11.6**	**11.7**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**	**12.8**	**12.8**	**12.9**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
						Net	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	12	12	12
Mazinaw DS	Tx	T1	BY	N/A	9.3	Load	**4.0**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.2**	**4.2**	**4.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**5.3**	**5.3**	**5.3**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
						Net	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
Mountain Chute DS	Tx	T1	BY	N/A	11.6	Load	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pembroke TS	Tx	T1/T2	JQ	M1 M2 M3	57	Load	**53.1**	**53.2**	**54.5**	**54.8**	**55.0**	**56.2**	**56.3**	**57.6**	**57.9**	**59.1**	**59.3**	**60.5**	**60.6**	**61.6**	**62.5**	**63.6**	**64.6**	**65.6**	**66.5**	**67.5**	**68.5**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.5	0.8	1	1.2	1.3	1.6	1.9	2.1	2.3	2.5	2.6	2.6	2.5	2.6	2.6	2.6	2.5	2.5	2.5
						Net	53	53	54	54	54	55	55	56	56	57	57	58	58	59	60	61	62	63	64	65	66
Petawawa DS	Tx	T1/T2	BY	N/A	20.2	Load	**10.2**	**10.5**	**10.8**	**11.0**	**11.3**	**11.5**	**11.8**	**12.0**	**12.3**	**12.6**	**12.9**	**13.1**	**13.4**	**13.7**	**13.9**	**14.1**	**14.4**	**14.6**	**14.9**	**15.2**	**15.5**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.2	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1	1
						Net	10.0	10.2	10.4	10.6	10.8	11.0	11.2	11.4	11.6	11.9	12.1	12.3	12.5	12.8	13.0	13.2	13.5	13.7	14.0	14.2	14.5

APPENDIX F. LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
GS	Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DER	Distributed Energy Resource
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme
TWG	Technical Working Group