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BY EMAIL AND RESS

December 2, 2025

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-2025-0290 – Hydro One Networks Inc. Leave to Construct and Expropriation Application – Welland-Thorold Project – Updated Application and Evidence

On November 17th 2025, Hydro One Networks Inc. ("Hydro One") sought relief from the Ontario Energy Board's ("OEB") for an Order or Orders with respect to the construction of transmission facilities in the Niagara area ("WTPL Project" or "the Project").

Hydro One is providing an update to the prefiled evidence to reflect that the Independent Electricity System Operator ("IESO") System Impact Assessment ("SIA") and the Customer Impact Assessment ("CIA") for the Project are now final. The conclusions of both the final SIA and CIA remain unchanged from the draft reports. The SIA continues to contain confidential information that has been removed in accordance with the justifications provided for in Hydro One's November 17, 2025 application.

Hydro One has updated the following schedules to reflect that the CIA and SIA are now final and jointly referred to as the Updates.

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A-01-01	Page 3
B-01-01	Page 2&5
B-02-01	Page 2
B-03-01	Page 1
B-07-01	Page 1
B-09-01	Page 1
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F-01-01	Page 1 and Attachment 1
G-01-01	Page 1 and Attachment 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

c/ Gord Nettleton
Monica Caceres

EXHIBIT LIST

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	1	3		List of Acronyms and Abbreviations
B				
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	2	1	2	General Area Map Inclusive of Future SS For Reference
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	2	1	4	Schematic Diagram of Crowland TS
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	3	1		Evidence In Support of Need
	3	1	1	IESO Supplemental Evidence to Support the Need for the Project
	4	1		Project Categorization and Classification
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	6	1		Quantitative and Qualitative Benefits of the Project
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	10	1		Revenue Requirement Information and Deferral Account Requests

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APPLICATION TABLE OF CONCORDANCE

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Exhibit	Content	FR Section	Hydro One S.92 Application Section
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LIST OF ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	**Acronym or Abbreviation Expansion**
A	Amperes
AC/DC	Alternating Current / Direct Current
ACSR	Aluminium-Conductor Steel-Reinforced cable
ACSS	Aluminum- Conductor Steel-Supported
AACE	Association for the Advancement of Cost Engineering
ACSR/TW	Aluminium-Conductor Steel-Reinforced, trapezoidal shaped cable
AFUDC	Allowance for Funds Used During Construction
ATP	Affiliate Transmission Projects
C	Celsius
CIA	Customer Impact Assessment
Class EA	Class Environmental Assessment
CSA	Canadian Standards Association
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
EA	Environmental Assessment
EPC	Engineering, Procurement and Construction
ESR	Environmental Study Report
ECI	Early Contractor Involvement
ECI-EPC	Refers to an ECI delivery model that engages the services of an external OE and the services of EPC contractors.
Hydro One *(HONI)*	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
ISD	Investment Summary Document
ISOC	Integrated System Operating Center
IEP	Integrated Energy Plan
JRAP	Joint Rate Application

Acronym or Abbreviation	**Acronym or Abbreviation Expansion**
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
m	Meter
MECP	Ministry of the Environment, Conservation and Parks
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
ORTAC	Ontario Resource and Transmission Assessment Criteria
ROW	Right-of-Way
RPP	Regulated Price Plan
SCADA	Supervisory Control and Data Acquisition system
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
TSP	Transmission System Plan
UTR	Uniform Transmission Rates
WTPL	Welland-Thorold Power Line

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. ("**Hydro One**") pursuant to s. 92 of the *Ontario Energy Board Act, 1998* (the "**Act**") for an Order or Orders granting leave to construct transmission line facilities ("**Welland Thorold Power Line Project" or "WTPL" or "Project"**) in the Niagara area.

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.

AND IN THE MATTER OF an Application by Hydro One pursuant to s. 99(1) of the Act for authority to expropriate certain land interests.

APPLICATION

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 Ontario Energy Board ("OEB") pursuant to s. 92 of the Act for an Order or Orders granting leave to construct a new 230kV double-circuit transmission line between Abitibi Consolidated Junction and Crowland TS in the

3. Niagara area. The approximate length of the transmission line facilities is 18.5 km. In addition to the line work, station expansion work will be required on property owned by Hydro One at Crowland TS on Hydro One-owned lands. Protection, control and telecommunications modifications will be also completed at three remote stations[1] to accommodate the new 230 kV line and Crowland TS. Additionally, and as a separate project, a new sectionalizing station, Crowland SS, will be constructed to allow proper protection and load capacity in accordance with recent requirements defined in the Independent Electricity System Operator ("**IESO**") Final System Impact Assessment ("**SIA**"). While considered as a functionally distinct project that is needed only after completion of the Welland Thorold Power Line, information about the Crowland SS has been included in this application for purposes of assisting the OEB in its determination of the relief sought in this Application.

4. Assuming the requested section 92 relief is granted, Hydro One is also seeking relief pursuant to section 99(1) of the Act for authority to expropriate certain interests in the lands as more particularly described and shown in the plans and descriptions attached in **Exhibit E, Tab 1, Schedule 1**. The expropriation relief sought in this Application is limited to a finite number of properties where Hydro One has identified issues that effectively prevent Hydro One from engaging in any discussions with the landowners as the landowners cannot be located, or title information has not provided Hydro One with accurate landowner contact information. The expropriation relief sought, if granted, will afford Hydro One additional time to address any land registration issues resulting in these circumstances, thereby mitigating risks of potential delays to the construction and in-service timing of the Project. Hydro One intends to continue its efforts in negotiating voluntary land acquisition agreements with all other landowners directly affected by the construction and operation of the Project.

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[1] Allanburg TS, Beck TS, and Port Colbourne TS

B. NATURE OF THE PROJECT

5. The Project is designed to provide up to 180 MW of incremental transmission capacity required to meet incremental forecast load demand and improve reliability in the area consistent with the recommendations made by the IESO in their report entitled the *Niagara Integrated Regional Resource Plan* (“**IRRP”**). A copy of the IRRP is found as **Attachment 2** in **Exhibit H, Tab 1, Schedule 1.** The need for the Project has been reaffirmed by the IESO in subsequent planning reports, including the Regional Infrastructure Plan which is provided as **Attachment 1** in **Exhibit H, Tab 1, Schedule 1.** The Project has therefore been identified as a non-discretionary development project in **Exhibit B, Tab 4, Schedule 1**.

6. Hydro One is committed to working with Indigenous governments and communities in a spirit of cooperation and shared responsibility. The company acknowledges that Indigenous governments and communities have unique historic and cultural relationships with their land and a unique knowledge of the natural environment. Forging meaningful relationships with Indigenous governments and communities based upon trust, confidence, and accountability is vital to advancing reconciliation and achieving Hydro One’s corporate objectives.

7. Hydro One has been engaging with Indigenous governments and communities since early in the development process and will continue that engagement and involvement in project decisions throughout the life cycle of the Project. Additionally, Hydro One has, and will continue to throughout the life cycle of the Project, engage in economic participation negotiations with impacted Indigenous communities including employment, training, contracting and equity participation in the Project.

8. Hydro One expects that after completion of the WTPL Project, ownership of the applied for transmission line facilities will be transferred and owned by a limited partnership consisting of two First Nations. As of the time of this Application, the limited partnership has not yet been formed. As negotiations are ongoing, Hydro One

is not currently able to provide commercial details. However, those details will be provided to the OEB once the limited partnership is formed and through subsequent transmission license and asset transfer applications made to the OEB.

9. Hydro One has proposed that all transmission line costs associated with the Project be accounted for in the OEB-approved ATP regulatory account and included in rate base only after the OEB reviews and approves the clearance of this deferral account. For reference purposes, further information on the ATP regulatory account is provided at **Exhibit B, Tab 10, Schedule 1**. Hydro One is not anticipating the limited partnership to impact the Project cost estimates provided at **Exhibit B, Tab 7, Schedule 1**.

10. The 230kV conductor selected by Hydro One to construct the new transmission line has been 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 at **Exhibit B, Tab 5, Schedule 1**.

C. PROJECT LAND REQUIREMENTS

11. An overview map of this area is provided in **Exhibit B, Tab 2, Schedule 1, Attachment 1** and schematic diagrams of the proposed Project can be found at **Exhibit B, Tab 2, Schedule 1, Attachments 3 to 5**.

12. New permanent land rights will be required to complete the Project. Temporary rights for construction purposes will also be required at specific locations along the corridor. Further information regarding the real estate needs to complete this project is provided in **Exhibit E, Tab 1, Schedule 1**.

13. The Project is subject to the applicable Class EA process in accordance with the *Ontario Environmental Assessment Act.* A draft Environmental Study Report was issued on July 11, 2025 followed by a 30-day comment period. Hydro One anticipates

14. filing the Final ESR and Statement of Completion with the Ministry of Environment, Conservations and Parks ("MECP") shortly.

15. The proposed in-service date for the Project is August 2029, assuming a construction commencement date of June 2026 and an OEB approval of this Application by May 2026. A project schedule is provided at **Exhibit B, Tab 11, Schedule 1**.

16. The IESO has provided Hydro One with the Final SIA. The Final SIA indicates 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. The IESO's Final SIA is provided as **Exhibit F, Tab 1, Schedule 1, Attachment 1.**

17. Hydro One has completed a Final Customer Impact Assessment ("**CIA**") in accordance with Hydro One's connection procedures. A copy of the Final CIA is provided as **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.

18. As of the date of this application, the forecast total capital cost of the Project is $311 million. Details pertaining to these costs are provided at **Exhibit B, Tab 7, Schedule 1**.

19. Based on the forecast costs and load growth, the expected rate impact arising from this work (using 2025 OEB-approved uniform transmission rates as filed in **Exhibit B, Tab 9, Schedule 1)** is a $0.11/month increase on a typical residential customer's bill under the Regulated Price Plan ("**RPP**").

20. This Application is also seeking approval of the forms of the agreement offered or to be offered to affected landowners, pursuant to s. 97 of the Act. The majority of these agreements are in the same form as previously approved in prior Hydro One's leave

21. to construct proceedings. The forms of the applied-for agreements are found as attachments to **Exhibit E, Tab 1, Schedule 1**.

22. 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 OEB's final decision on this Application.

D. DESCRIPTION OF LAND INTERESTS TO BE EXPROPRIATED

23. As mentioned above, the expropriation relief sought in this Application is limited to a finite number of properties where Hydro One has identified title issues with lands necessary for the Project. Hydro One has attempted and not been able to locate or contact any of the listed individuals **Exhibit E, Tab 1, Schedule 1, Attachment 11**. Some of the listed individuals are deceased or have not responded to Hydro One's outreach such that Hydro One has been unable to negotiate or secure voluntary agreements with the individuals identified in **Exhibit E, Tab 1, Schedule 1, Attachment 11**. Therefore, Hydro One is requesting expropriation of certain interests in the lands, as detailed and illustrated in the plans and descriptions provided in **Exhibit E, Tab 1, Schedule 1**.

24. This list at **Exhibit E, Tab 1, Schedule 1, Attachment 11** is not inclusive of all permanent or temporary easement interests Hydro One requires to access, construct, operate and maintain the Project, as some land rights continue to be negotiated and secured on a voluntary basis. Should there be a need to secure expropriation authority in the future to secure those additional land rights, Hydro One intends to make a separate application

25. A description of the lands and the specific interests in lands in which Hydro One is seeking authority to expropriate is attached as **Exhibit E, Tab 1, Schedule 1, Attachment 11**. Hydro One has conducted a search of title to identify the current registered property owners, those who hold registrable interests in the lands, and

those with any interest in the lands directly affected by the request to expropriate. The names of these individuals are listed by property in the attachment.

26. Attached hereto as **Exhibit E, Tab 1, Schedule 12** are copies of the reference plans, suitable for registration, showing the lands over which authority to expropriate the interests set out in **Exhibit E, Tab 1, Schedule 11** is being requested and the registered owners thereof.

E. PUBLIC INTEREST

27. Based on the foregoing, and the information provided in the pre-filed evidence, Hydro One submits that the relief sought in this application is in the public interest. The Project meets the need of the transmission system and improves quality of service and reliability and reduces the price paid by ratepayers.

28. Construction and operation of these facilities is needed to maintain the safe and reliable transmission of electricity using the IESO-controlled grid. The expropriation authorization sought herein is intended as a practical and efficient way to address initial challenges associated with the land assembly process for new electricity transmission developments. Following any grant of leave to construct made pursuant to section 92, Hydro One submits that granting expropriation authorization, as proposed, will reasonably reduce the risk of delays and facilitate Project construction proceeding in a timely manner. These outcomes are in public interest.

29. Additionally, approval of the Application will provide meaningful opportunity for Indigenous participation. On June 12, 2025, the Government of Ontario released Energy for Generations, an Integrated Energy Plan (“IEP”) which provides a 25-year roadmap for powering Ontario’s growth and economic development in accordance with the province’s Affordable Energy Future Vision. The IEP highlighted the importance of creating opportunities for meaningful Indigenous participation in energy projects. This Project will do just that, it is more than infrastructure it is a collaboration that supports Indigenous-led economic development. As previously stated, Hydro

One expects that after completion of the WTPL Project, ownership of the applied for transmission line facilities will be transferred and owned by a limited partnership consisting of two First Nations. It is in the public interest to support Indigenous partnerships, as stated in the government's IEP.

F. REQUESTED RELIEF

30. Hydro One requests:
    a) An Order or Orders made pursuant to section 92 of the Act granting leave to construct the Project; and
    b) An Order or Orders made pursuant to section 99 of the Act granting the necessary authority to expropriate the land interests more particularly described in Exhibit E, Tab 1, Schedule 1.
    c) Such other relief as Hydro One may request or as the Board may direct.

31. 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

G. NOTICE

32. 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
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b) **The Applicant's Counsel:**

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Partner
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c) The Applicant's Counsel:

Monica Caceres
Assistant General Counsel
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PROJECT OVERVIEW DOCUMENTS

Hydro One is seeking approval to construct transmission facilities to address the needs and recommendations defined by the IESO referenced in **Exhibit B, Tab 3, Schedule 1** and **Exhibit H, Tab 1, Schedule 1**. More specifically, the relief sought in this application will ensure sufficient capacity to supply the forecast load and improve reliability in the Niagara area.

The Project will construct approximately 18.5 km of new transmission line inclusive of 11.5 km of new 230 kV double circuit transmission line and 8 km of a new triple circuit transmission line (two 230 kV circuits, single 115 kV circuit) initiating from Abitibi Consolidated Junction to Crowland TS.

As developed through the Class EA process[1], the majority of the line work is located in existing transmission corridors. The transmission line will consist of both new and repurposed right-of-way ("ROW"). The new section of 230 kV ROW will originate from Abitibi Consolidated Junction to Allanburg TS while the repurposed section spans from Allanburg TS to Crowland TS.

The line component of the Project can be segmented into three sections:

New ROW from Abitibi Consolidated Junction to Allanburg TS

The new ROW will originate its tap off point from two existing 230 kV transmission circuits connecting Sir Adam Beck TS, Middleport TS, and Beach TS, with nomenclatures Q24HM and Q29HM. The route proceeds south approximately 3.5 km to Allanburg TS.

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[1] https://www.hydroone.com/about/corporate-information/major-projects/welland-to-thorold

Transmission Corridor Between Allanburg TS and Michigan Junction

Hydro One will repurpose a section of the existing 115 kV transmission corridor between Allanburg TS and Michigan Junction (circuits D3A/A3C) which is approximately 8 km in length. The existing 115 kV structures, conductor and associated components will be dismantled, removed, and replaced, and the corridor will be re-used, to accommodate the proposed 230 kV double-circuit and 115 kV single-circuit transmission line.

Michigan Junction to Crowland TS

Hydro One will repurpose a section of an idle 115 kV transmission line corridor between Michigan Junction and Crowland TS that is approximately 7 km in length. The existing 115 kV structures, conductor and associated components will be dismantled, removed, and replaced, and the corridor will be re-used, to accommodate the proposed 230 kV double-circuit transmission line.

The Project will also necessitate the completion of station work. To complete the Project, Hydro One will convert Crowland TS from a 115 kV supply to a 230 kV supply to connect to the new 230kV transmission line to alleviate loading on the existing 115 kV system. The conversion of Crowland TS will include the installation of two new 230/27.6 kV transformers with associated equipment, and installation of protection, control and telecom works. The Project will also require modifications to telecommunications facilities at Sir Adam Beck TS, Beach TS and Middleport TS. Modifications and additions to protection and control, SCADA, metering, and AC/DC station service at Crowland TS, are required to provide protection, control and status of the new 230 kV facilities.

As a requirement of the Final SIA provided at **Exhibit F, Tab 1, Schedule 1,** Hydro One has also been directed to build a new sectionalizing station, referred to as Crowland SS, between Beck TS, Beach TS and Middleport TS after the Project.

A map showing the geographic location of the facilities for the Project as well as schematic diagrams of the proposed facilities for the Project are provided in **Exhibit B, Tab 2, Schedule 1, Attachment 1** and **Exhibit B, Tab 2, Schedule 1, Attachments 3 and 4**, respectively. A map showing the potential geographic location of Crowland SS as well as schematic diagrams for Crowland SS are also provided for reference at **Exhibit B, Tab 2, Schedule 1, Attachments 2 and 5**, respectively.

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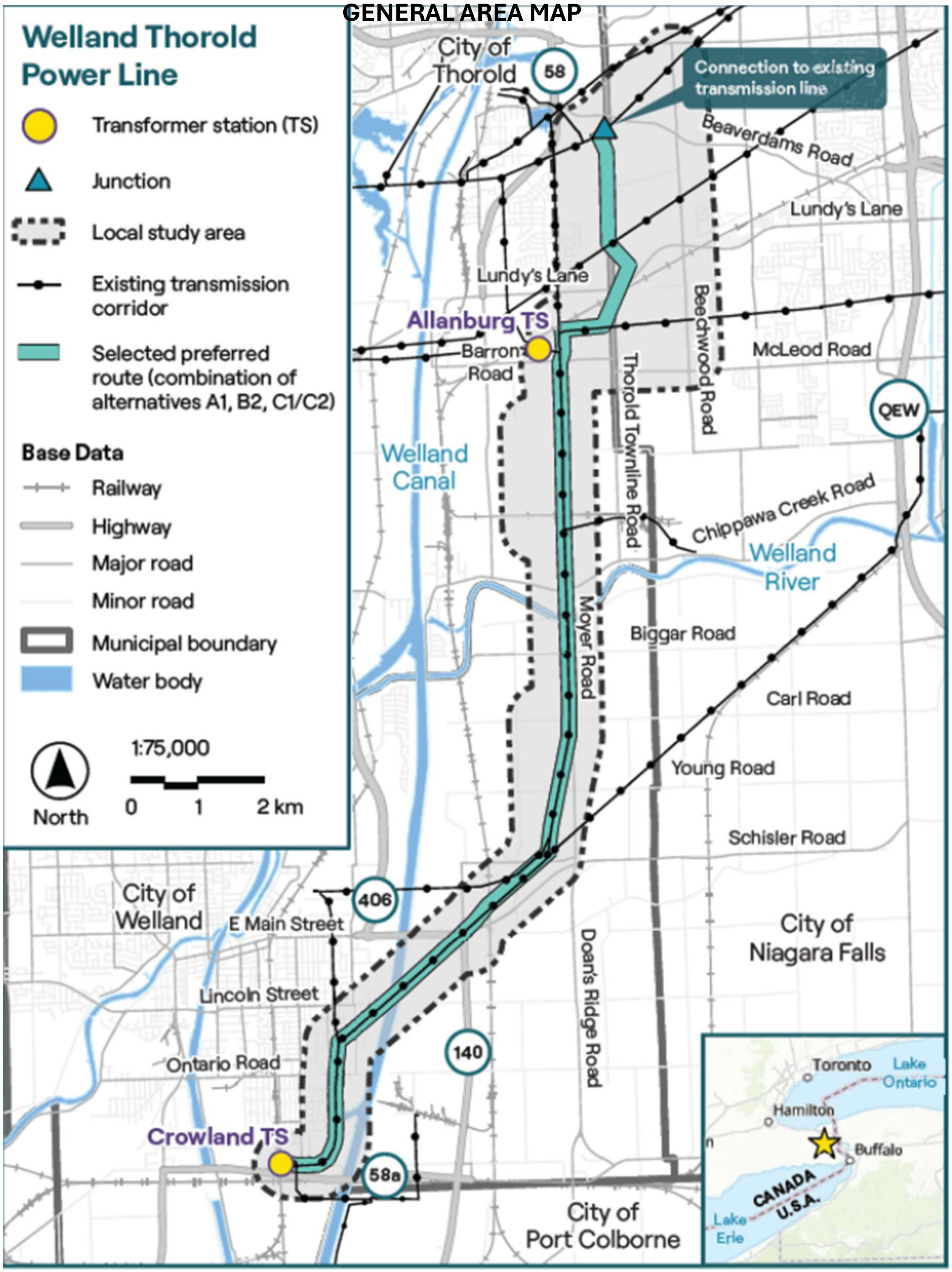
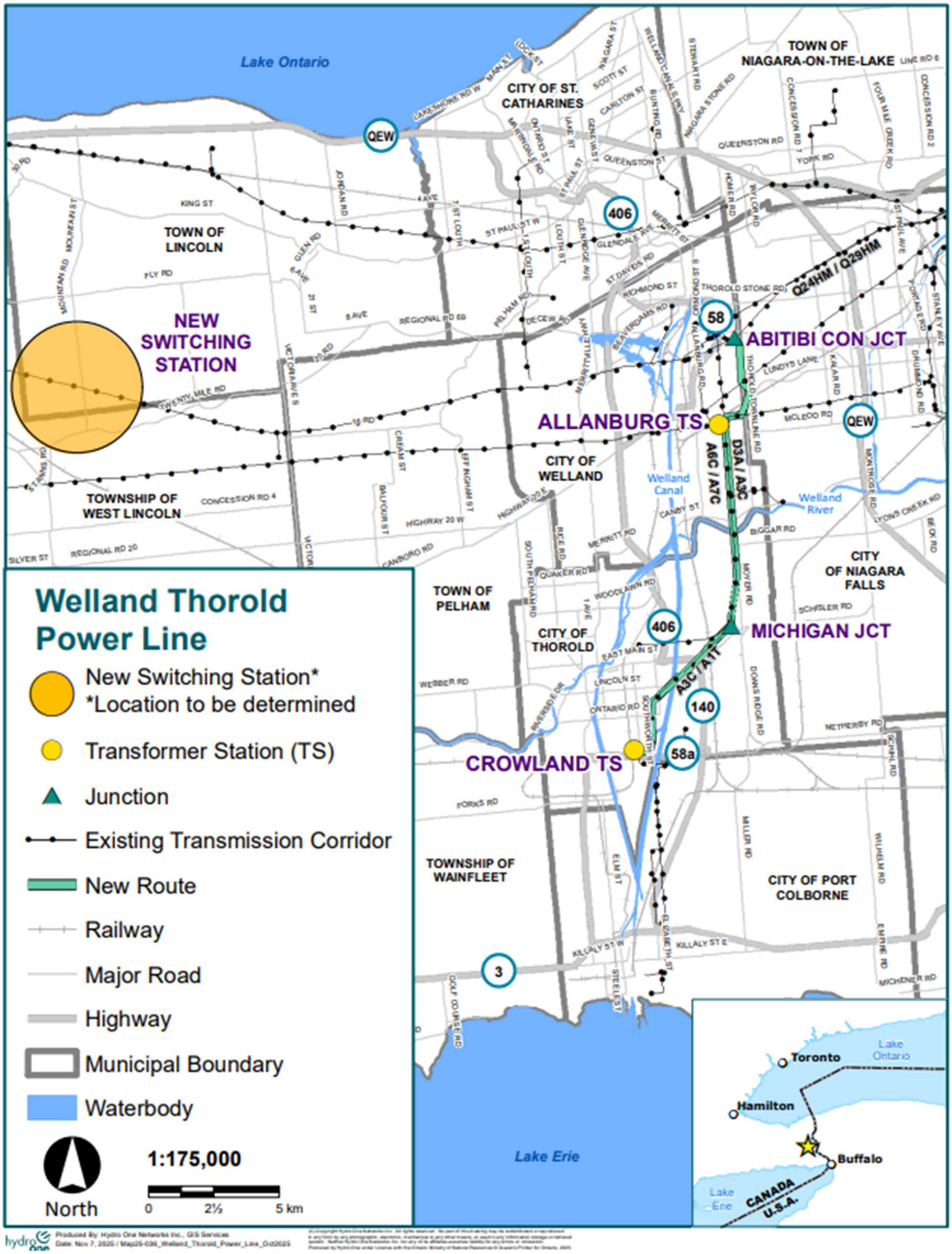
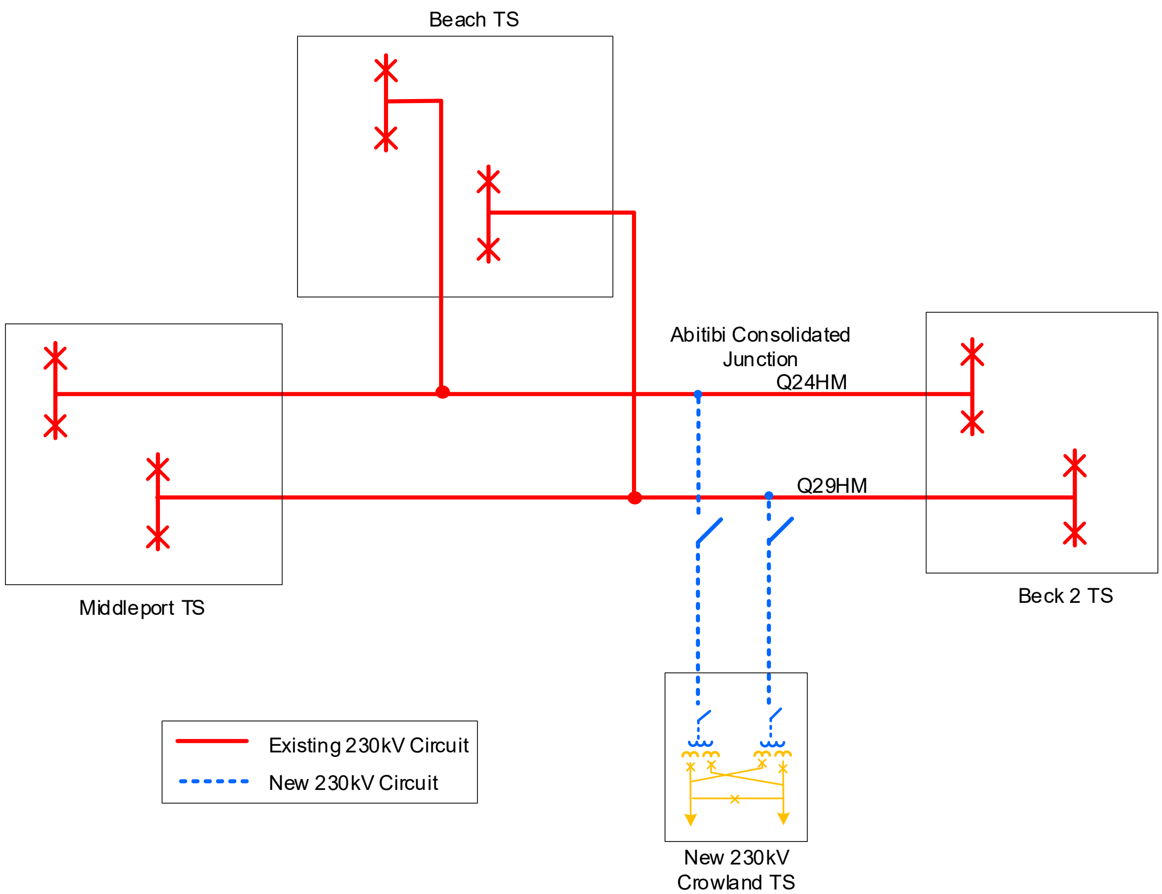
GENERAL AREA MAP



GENERAL AREA MAP INCLUSIVE OF FUTURE SS FOR REFERENCE

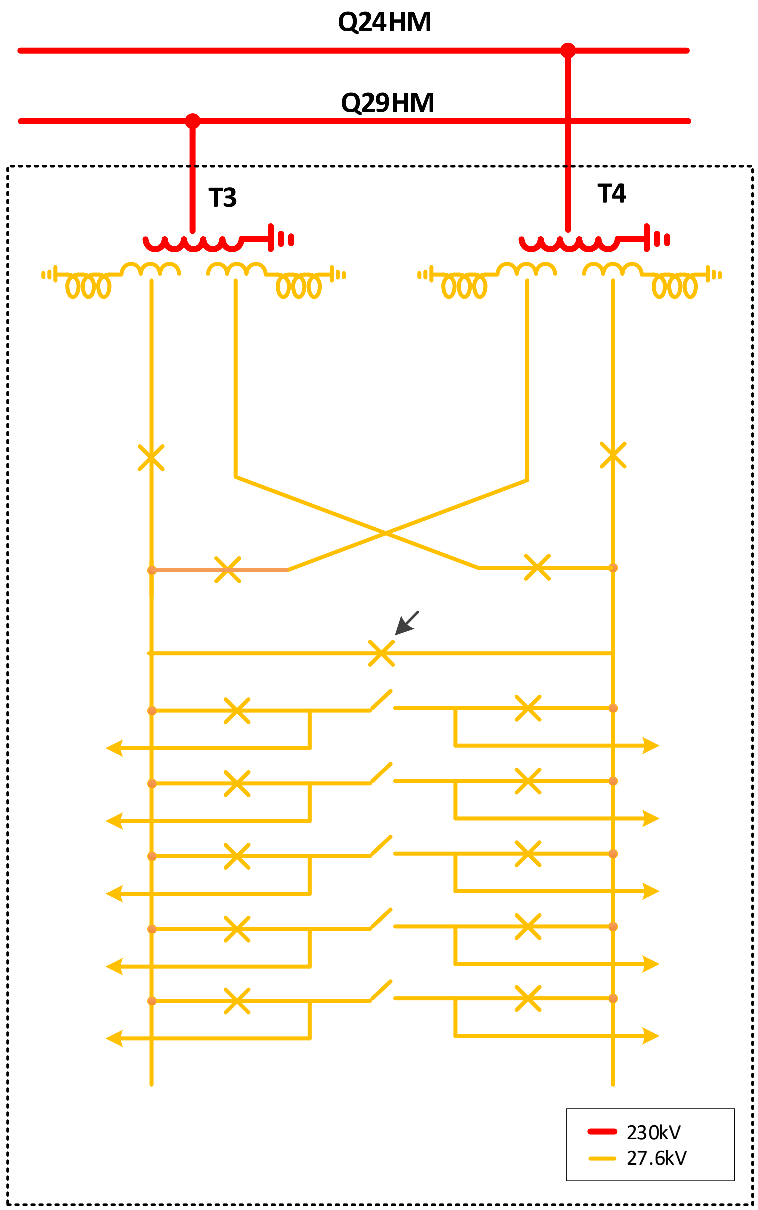


PROPOSED FACILITIES:
Sir Adam Beck 2 TS x Middleport TS x Beach TS Tap Junction
SIMPLIFIED SCHEMATIC DIAGRAM

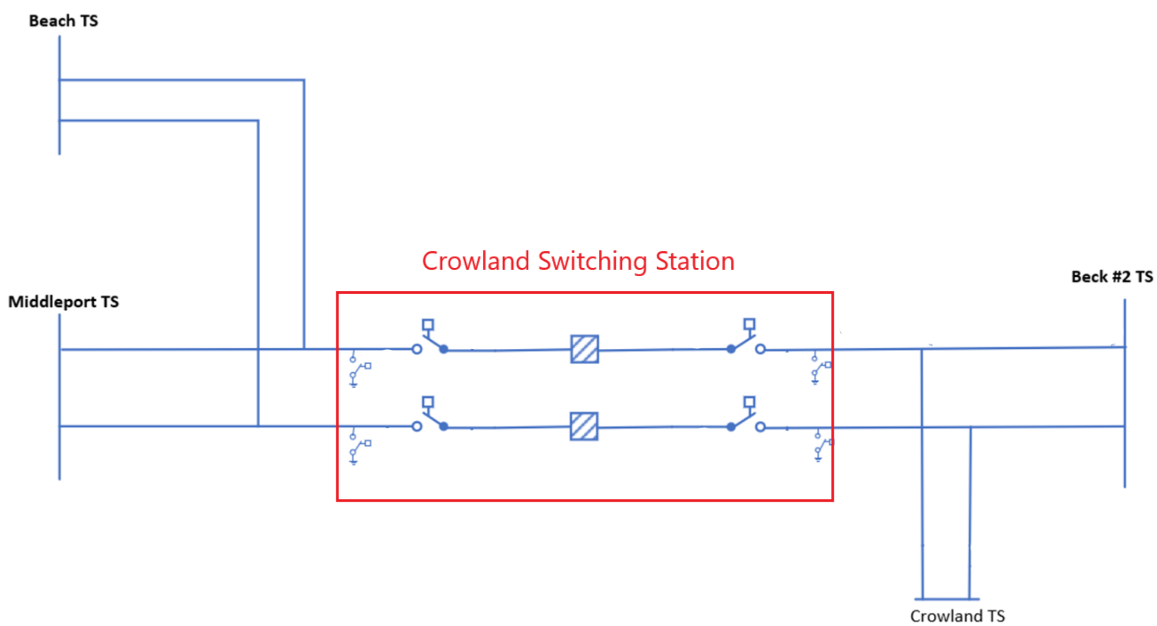


1 **PROPOSED FACILITIES:**

2 **Crowland TS SIMPLIFIED SCHEMATIC DIAGRAM**



PROPOSED FACILITIES:
Crowland Switching Station
SIMPLIFIED SCHEMATIC DIAGRAM



EVIDENCE IN SUPPORT OF NEED

The Project is needed to increase the supply capacity between Abitibi Consolidated Junction and Crowland TS to support the continued load growth in the Niagara area and improve reliability in the area. The need for the Project has been identified in multiple regional planning documents being explicitly identified in the IESO's 2022 Niagara Integrated Regional Resource Plan and the 2023 Niagara Regional Infrastructure Plan. These plans have been attached for reference at **Exhibit H, Tab 1, Schedules 1 and 2.**

The Project will address multiple needs identified in the regional planning documents, more specifically, the Project will address:

i. Niagara Region 115 kV supply capacity concerns[1]: the loads on the Niagara Region 115kV system exceeds the 115 kV system supply capability under certain contingency conditions which result in three out of the four autotransformers being out of service at Allanburg TS;
ii. Overloading concerns on circuits A6C and A7C within the 115 kV network by transferring the Crowland TS load to a 230 kV supply[2];
iii. Crowland TS capacity and asset renewal needs[3]; as well as
iv. Load security concerns on circuits A6C and A7C as the load forecast on these circuits exceeds the permissible limit set by ORTAC.[4]

As detailed in the Final SIA, the Project will also require modifications to protection and telecommunications facilities at Sir Adam Beck TS, Beach TS and Middleport TS to accommodate the new transmission line. Specifically, the current protection scheme is insufficient to provide adequate protection for the newly added 230 kV circuit. To improve system reliability and ensure adequate asset protection, it is recommended to sectionalize

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[1] IESO Regional Infrastructure Plan – July 12, 2023 – Section 7.2.1
[2] Ibid. Section 7.1.2
[3] Ibid. Section 7.3.2 and 7.4
[4] Ibid. Section 7.5

Q24HM and Q29HM by installing inline breakers on each circuit west of Abtibi Consolidated Junction. Additionally, a new sectionalizing station will be added to allow for proper protection for the newly added 230kV circuit.

The IESO has supplemented the evidence filed in this Application with **Attachment 1 of this Schedule** that reinforces the need for the Project based on the fact that Niagara electricity demand is trending closer to the high forecast in the preceding planning documents.

Supplemental Evidence to Support the Need for the Welland Thorold Power Line Project

Independent Electricity System Operator

Connecting Today.
Powering Tomorrow.

Table of Contents

1. Executive Summary

The Independent Electricity System Operator (IESO) is providing this report in support of the Leave-to-Construct (LTC) application for the Welland Thorold Power Line project (the "Project") in accordance with the requirements of the Ontario Energy Board's (OEB) Chapter 4 of the Filing Requirements for Electricity Transmission Applications (the "Filing Requirements").

Section 4.3.2.3 of the Filing Requirements requires the applicant to provide evidence that identifies the recommended and planned transmission and non-wire projects in any regional plans and/or bulk plans that have "linkages and/or interdependencies to the applied-for transmission project." In the context of an LTC application, "linkages and/or interdependencies" refers to projects (including the Project) where the impact of one or more recommended and planned transmission and non-wire projects has the potential to affect the need for, or viability of, another such project. Section 4.3.2.3 further specifies that "[s]uch projects, or those under consideration as part of an ongoing planning process, might span multiple regions."

The need and rationale for the Project is detailed in IESO's [1] published December 2022 ("2022 Niagara IRRP") and reconfirmed in the Niagara Regional Infrastructure Plan published July 2023. This Project is key to the regional transmission plan recommended to address the growing demand for electricity in the region due to economic development, particularly in the manufacturing industries. report[2] published December 2022 ("2022 Niagara IRRP") and reconfirmed in the Niagara Regional Infrastructure Plan published July 2023. This Project is key to the regional transmission plan recommended to address the growing demand for electricity in the region due to economic development, particularly in the manufacturing industries.

The purpose of this report is to provide the OEB with the most up to date and complete information to assess the LTC application for the Project since the Niagara IRRP was published in 2022. This report supplements the 2022 Niagara IRRP by providing evidence on the demand forecast changes and linkages between the Project and the plans for Southwestern Ontario. Overall, Niagara electricity demand is trending closer to the high forecast, further reinforcing the need for the Project.
Thus, without approval of the Project, these economic development projects would not be able to connect to the grid, which would require the IESO to reassess the Niagara region plan to address this need.

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[2] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/Niagara/niagara-IRRP-Report.pdf

2. Project Background

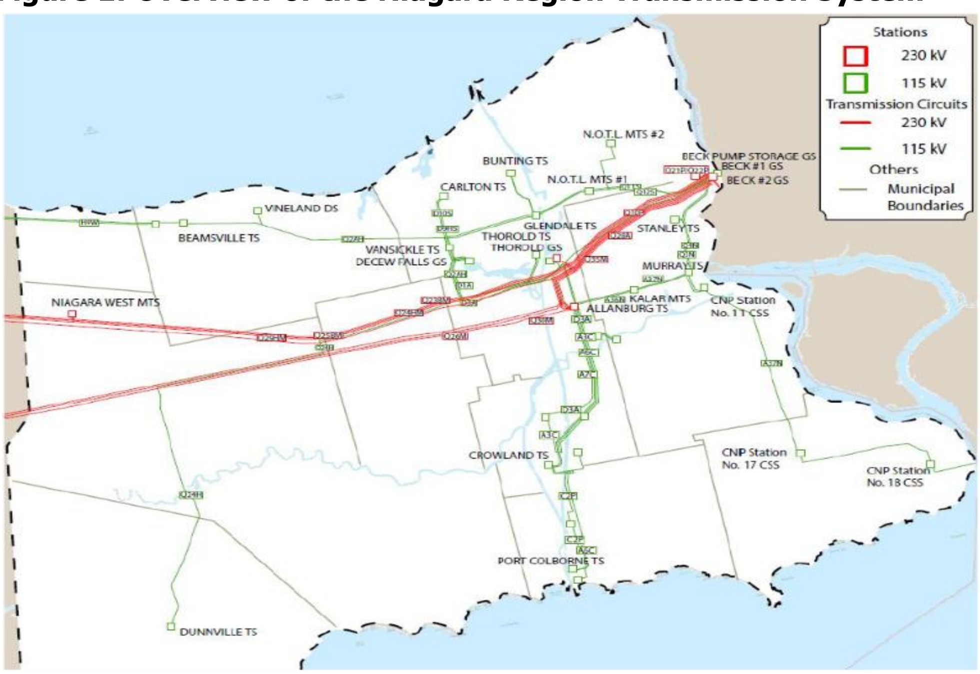
The IESO's role in the transmission planning and development process is in the determination of need, evaluation of alternatives, and recommendation of the most cost-effective solution to the supply need.[3] For the Project, this is detailed in the [2022 Niagara IRRP][4] report from December 2022, included in Exhibit B, Tab 3, Schedule 1.

The Project is part of an integrated solution recommended to meet the Crowland Transformer Station (TS) capacity and asset replacement needs, as well as the A6C/A7C load security, the A6C/A7C sub-system capacity needs, and Niagara 115 kV sub-system capacity needs. The recommended set of solutions was:

- The sections of 115 kV D3A/A3C circuits will be replaced with approximately 18 km of new 230 kV double-circuit supply lines tapping off Q24HM and Q29HM – this Project; and
- The replacement of Crowland TS with a 230 kV station (to address its asset replacement and capacity needs, offload the Niagara 115 kV sub-system, and mitigate the A6C/A7C load security need). As of 2024, planning and design activities for the Crowland TS replacement are underway, with a targeted in-service date of 2028.

Figure 1 provides a geographical representation of the Niagara region with the current electrical infrastructure.

Figure 1: Overview of the Niagara Region Transmission System



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[3] As per the *Electricity Act, 1998*, within the context of regional planning the IESO has responsibility to: engage in activities in support of the goal of ensuring adequate, reliable and secure electricity supply and resources in Ontario; conduct independent planning for electricity generation, demand management, conservation and transmission; and to collect and make public information relating to the short term, medium term and long term electricity needs of Ontario and the adequacy and reliability of the integrated power system to meet those needs.

[4] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/Niagara/niagara-IRRP-Report.pdf

Since 2022, the IESO has continued to monitor and plan for this region, and through that work has recognized changes to the following:

- The need, specifically the load forecast in Niagara and impact of targeted incremental electricity Demand Side Management (eDSM);[5]
- The near-term impact to reliability; and
- The broader transmission plan for the Niagara area.

The IESO has assessed each of these factors, detailed in this report, and found that they further reinforce the need established in the 2022 Niagara IRRP.

3. Updates to the Need

3.1 Load Forecast Update

The 2022 Niagara IRRP Reference forecast projected that electricity demand in the Niagara region would increase by 360 MW across the region between 2022 and 2041 in the reference scenario and almost 500 MW in the high scenario. The reference forecast was driven by moderate load growth from residential and urban area expansions and industrial loads concentrated around the Welland Canal included in the IRRP forecast. The high forecast scenario also included several large industrial customers whose connection was uncertain at the time of finalizing the reference forecast. Since the 2022 Niagara IRRP, a number of SIAs have been received for new load connection requests that are impactive to the need for the Project, totalling over 700 MW of step changes in demand for the area. A subset of these connection requests overlap with the projects included in the 2022 Niagara IRRP - 140 MW in the reference and 210 MW in the high forecast scenario. The remaining approximately 500 MW represents additional unanticipated load growth relative to the IRRP forecasts. Of the SIAs received, approximately 300 MW of load connections have been approved to date with in-service dates ranging from 2024 to 2027. In addition, there have been discussions with other potential load applicants in the Port Colborne area, which have not yet proceeded to the SIA phase. The Project is the first reinforcement required to provide additional points of connection in the area. The Niagara Bulk Plan, outlined in Section 5, is needed to determine further bulk reinforcement requirements to enable additional transmission supply in the region.

[5] Referred to as Conservation and Demand Management in the 2022 Niagara IRRP.

3.2 Electricity Demand Side Management

The 2022 Niagara IRRP identified an opportunity for eDSM programs to help capacity constraints in the Niagara region but due to the magnitude, timing, and nature of the need, it was found that non-wires alternatives alone were not sufficient to address the 200 MW need. However, targeting incremental eDSM for the 115 kV Niagara sub-system was recommended to manage load growth beyond the reference scenario. As of September 2025, the eDSM Retrofit program in Niagara had 5.9 MW of preapproved applications and approximately 400 kW of completed projects where the incentive has already been paid. This will contribute to near-term capacity but the Project is still required to address the remainder of the 200 MW need.

4. Near-Term Impact to Reliability

The ability to connect new industrial loads in the region will be constrained without the Project, delaying economic development initiatives. Furthermore, without the Project the aging infrastructure at Crowland TS and the limitations of 115 kV lines south to Crowland amplify reliability concerns for existing loads connected to the 115 kV lines, especially during high demand periods or contingency events.

As outlined in Section 3.1, electricity demand in the Niagara region is growing faster than the 2022 reference forecast. Even with the wires and non-wires recommendations in the area, there are concerns regarding how to maintain reliability in the near term.

Prior to the completion of the Project and potential bulk reinforcement recommendations, near-term load connections may be subject to a lower level of reliability. This includes increased exposure to load interruption risks during planned outages or equipment failures, notably in the A6C/A7C sub-system, where aging infrastructure and concentrated industrial demand increase the risk to system reliability. Load interruption may need to be coordinated to facilitate outages. The reliability risks are expected to be for a limited timeframe and there are actions available to manage them. These actions include operational coordination, temporary load transfer strategies and targeted eDSM deployment. However, operations will become more challenging if load continues to grow faster than forecast before the Project is in service.

5. Future Planning in Niagara

The IESO will initiate a bulk study for the Niagara region in Q4 2025, which will look at supporting demand growth in key load centers, while maintaining bulk transfer capacity on the transmission circuits that connect the Niagara Zone and the Southwest Zone – the Queenston Flow West (QFW) interface. The study will examine the sufficiency of the 230 kV bulk transmission system between Niagara, Middleport and Hamilton in the context of supporting current and future economic development and maintaining bulk transfer capacity.

The Project was an IRRP recommendation and has "committed" status in terms of the IESO connection process, so will be included in the base assumptions for the bulk study. In particular, the bulk study will consider supply along the 230 kV corridor where the Project will connect, to continue to support the high industrial load growth expected and future electrification initiatives.

This study is expected to take between 12 to 16 months to complete, with updates provided through the IESO's quarterly bulk engagement webinars.

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PROJECT CATEGORIZATION AND CLASSIFICATION

1.0 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 properly categorized as a non-discretionary project as it is being undertaken in accordance with direction from the IESO in the regional planning process described in **Exhibit B, Tab 3, Schedule 1** to increase the supply capacity between the City of Thorold and Welland to address forecast load growth.

2.0 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 Development Project as the proposed transmission facilities provide for additional system capacity and maintain reliability and quality of electricity supply.

Categorization and Classification

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

COST BENEFIT ANALYSIS AND OPTIONS

As described in **Exhibit B, Tab 3, Schedule 1,** the Project has been considered in previous regional planning documents and an analysis of the alternatives to address the needs in the region were contemplated in the regional planning documentation provided at **Exhibit H, Tab 1, Schedule 1, Attachments 1 and 2**. The reports conclude that the Project is the most cost-effective way to address the supply capacity and reliability needs of the area. The need and recommended solution for the Project have been reinforced by the IESO as documented in **Exhibit B, Tab 3, Schedule 1, Attachment 1** based on their most recent area forecasts.

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 Allanburg area and, b) optimize transmission line losses based on the expected load scenario. The conductor alternatives evaluated were:

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

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. A screening analysis was completed in accordance with Hydro One's Transmission Line Loss Guideline[1] to consider the impact of line losses on the Project. The screening analysis resulted in a change in alternative ranking and showed a similar Total Annual Cost between alternatives therefore a detailed 50-year 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

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

was done using varying values for the prices of energy and a capacity price of $164,052/MW consistent with Hydro One's Transmission Line Loss Guideline.

The NPV analysis undertaken defined the selected conductor as the most economical alternative. All three alternatives meet the capacity needs for the area, but the selected conductor, 1433.6 kcmil ACSS conductor, is the recommended alternative because it is the most cost-effective conductor when also taking transmission line losses into consideration.

As aforementioned, the transmission line loss analysis aligns with Hydro One's Transmission Line Loss Guideline and the transmission line loss analysis is available upon request.

QUANTITATIVE AND QUALITATIVE BENEFITS OF THE PROJECT

Further to the transmission system benefits already described in the regional planning documents detailed in **Exhibit B, Tab 3, Schedules 1**, and **Exhibit H, Tab 1, Schedule 1**, respectively, as well as the quantitative transmission line loss benefits described in **Exhibit B, Tab 5, Schedule 1**, the Project delivers other benefits listed below.

The Project will bring both short-term and long-term employment, training, and business opportunities to the region. This includes opportunities for both Indigenous and non-Indigenous communities, governments, and businesses to benefit from the construction, operation, and maintenance of the Project.

The implementation of the Project not only addresses the system and capacity needs for Crowland TS but also leverages the most sustainable solution that minimizes additional land use. The Project is subject to the applicable Class EA process in accordance with the *Ontario Environmental Assessment Act.* Class and Hydro One filed a Draft Environmental Study Report for the Project on July 11th, 2025. The selected route for the Project utilizes approximately 70% of existing transmission corridor lands, and overall impacts to the natural and socio-economic environments are minimized.

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APPORTIONING PROJECT COSTS AND RISKS

The estimated total cost of the Project undertaken by Hydro One is $311.4M[1], the breakdown by line and station capital costs are shown below in Table 1 and Table 2 respectively.

Table 1 - Line Cost

	Estimated Cost ($000's)
Materials	25,500
Labour	14,000
Equipment Rental & Contractor Costs	99,300
Sundry	2,100
Contingencies	33,200
Overhead [2]	4,300
Allowance for Funds Used During Construction [3]	16,200
Real Estate	40,300
Total Line Work	**234,900**

Table 2 - Transformer Station Cost

	Estimated Cost ($000's)
Materials	24,595
Labour	9,600
Equipment Rental & Contractor Costs	27,500
Sundry	5
Contingencies	6,100
Overhead [2]	1,400
Allowance for Funds Used During Construction [3]	7,300
Real Estate	-
Total Transformer Station Work	**76,500**

[1] There will be an additional $3.4M of OMA removal costs associated with constructing this Project. Additionally, as aforementioned, the forecast Project cost does not include the costs associated with Crowland SS as that work is considered a seperate project required after the WTPL Project that was identified in the recent Final SIA. However, for the purposes of providing costs associated with the related Crowland SS, the AACE Class 5 forecast estimate for Crowland SS is $55.6M.
[2] Overhead Costs allocated to the Project are for corporate services costs. For this capital project, these overhead costs are charged through an ECI-EPC overhead capitalization rate (EB-2023-0198) for the line and station costs. As such they are considered "Indirect Overhead".
[3] AFUDC is calculated using 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.

The cost of the work provided above allows for the schedule of approval, design and construction activities provided in **Exhibit B, Tab 11, Schedule 1**. The cost estimates provided in Table 1 and 2 of this Schedule, and similarly the Project Schedule provided at **Exhibit B, Tab 11, Schedule 1,** are based on a project definition equivalent to a Class 3[4] under the AACE International (formerly the Association for the Advancement of Cost Engineering) estimate classification system[5].

To achieve that project definition, the Project has proceeded with procurement of long lead materials, detailed engineering and design activities, and subsurface verification through geotechnical studies. The preferred route for the Project has also been established through the Class EA process in accordance with the *Ontario Environmental Assessment Act.* As further described in **Exhibit E, Tab 1, Schedule 1** Hydro One has achieved voluntary early access agreements on 78% of the properties affected by the corridor.

The Project cost estimate is based on a fixed price EPC contract, and the selection of the EPC contractor used a two-stage process that is slight variant but ultimately akin to the OEB-approved ECI-EPC project delivery model.[6] The first stage was to utilize an external owner's engineer and qualify the EPC contractor based on experience and capacity to perform many of the development functions that under the standard Hydro One EPC delivery model would be performed internally by Hydro One. This process allowed the EPC contractors to obtain competitive market pricing from their suppliers and vendors and to identify and evaluate engineering, procurement and construction risks and opportunities during the development of their offer. Thus, the cost estimate reflects current market-tested EPC cost to deliver the project and corresponding contingency cost to account for risks that will be transferred to the EPC contractor. Hydro One has entered into an agreement with the selected EPC contractor for the transmission line and station, with a

[4] An estimate range of -20%/+30%
[5] As per 96r-18 Cost Estimate Classification System – EPC Power Transmission Line Infrastructure Industries recommended practice document.
[6] The OEB has reviewed and approved use of the ECI-EPC methodology in previous leave to construct proceedings including dockets EB-2023-0198 and EB-2024-155.

Limited Notice to Proceed on early activities to advance the contractors' long lead procurement process.

1.0 RISKS AND CONTINGENCIES

As with most projects, there are risks associated with estimating costs. Hydro One's 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 suggested for this Project include the following:

- **Outage Constraints:** There is a risk of securing required transmission system outages due to system instability, weather or environmental reasons, insufficient generation, competing transmission system outages in the area, customer requirements, or critical load requirements. Time-of-year can also dictate the outages schedule and potential for cancellations. Outage delays or cancellations may cause schedule disruptions and increased costs.
- **Approvals, Permits and Authorizations:** Risk of delays or cost escalation in obtaining required approvals including leave to construct, and all necessary land rights (e.g., should property owners refuse Hydro One's voluntary agreements leading to the necessity of further expropriation relief) that may cause delay or disruption to the construction schedule and additional cost.
- **Archaeology Finds:** If archaeological assessments determine potential for significant archaeological sites on the route, advanced studies could have cost and schedule impacts if unplanned finds cannot be avoided or mitigated.

To mitigate these risks Hydro One has:

1. Established communication plans regarding schedule updates between Hydro One and the EPC contractors to foresee any possible delays due to outage or access constraints. Crew allocation will be optimized to minimize delays and additional costs.
2. Proactively submitted regulatory applications, project permit and authorizations well in advance of the construction start of the Project, including the Final ESR with the MECP and this application for OEB relief.
3. Archaeological assessment can be prioritized for sections that have limited capacity for adjustment (for example, Michigan Junction, and the location of angle structures). Access for archaeological assessments has been advanced as much as possible by leveraging existing access.

Cost contingencies that have not been included in the total contingency suggested for this project, due to the unlikelihood or uncertainty of occurrence, include:

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

2.0 COSTS OF COMPARABLE PROJECTS - LINES

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 5 compares the line cost of the Project with three other recent comparable projects.

- **Guelph Area Transmission Refurbishment Project:** Upgraded an existing 115 kV double-circuit transmission line to construct a new 230 kV double-circuit transmission line (approximately 5 km) to reinforce the electricity supply and minimize the impact of major transmission outages on customers in the area. The majority of the line upgrade work involved replacing the existing 115 kV double wood pole line, B5G/B6G, between CGE Junction and Campbell TS, with a 230 kV line utilizing a combination of steel lattice towers and steel pole structures. Leave to construct approval for this project was provided under OEB docket EB-2013-0053.

- **Power South Nepean Project**: Upgraded an existing 115 kV single-circuit transmission line to construct a new 230 kV double-circuit transmission line (approximately 12.2 km) to address capacity needs in the South Nepean Area of Ottawa. The new 230 kV double-circuit transmission line replaced approximately 10.9 km of the existing 115 kV single-circuit transmission line (S7M) from West Hunt Club Road to Cambrian Road and extended an additional approximate 1.3 km from Cambrian Road to the new MTS. Leave to construct approval for this project was provided under OEB docket EB-2019-0077.
- **Woodstock Area Transmission Reinforcement:** Upgraded an existing 115 kV double-circuit transmission line (W7W/W12W) to construct a new 230 kV double circuit transmission line between Ingersoll and Woodstock (approximately 13.6 km) to address capacity needs in the Woodstock Area. The new 230 kV double-circuit transmission line was connected to the existing 230 kV double circuit transmission line (M32W/M33W) at Ingersoll TS and replaced approximately 12 km of the existing 115 kV ROW from Ingersoll TS to the new Karn TS and extended from Karn TS to Woodstock TS along the existing ROW. Leave to construct approval for this project was provided under OEB docket EB-2007-0027.

These projects were selected as reasonable comparable because they are all 230kV double-circuit transmission lines of similar length and all project scopes included works on 115 kV infrastructure to complete the project.

For the purposes of the comparison, Hydro One has excluded the real estate costs from all comparable projects, as well as the cost for the triple circuit, larger structures, inefficiencies due to corridor nonlinearity and the adjacent energized line, and the additional cost to confine the line to a narrower right of way from the WTPL project because these are project-specific requirements and not comparable between the projects.

The route selected through the Class Environmental Assessment (EA) for Transmission Facilities includes the re-use of an existing, partially idle corridor in one section. One circuit is currently in-use and will need to be included in the newly constructed transmission line, which necessitates the use of triple circuit structures in this section of the line. While this was the preferred route from the Class EA and minimizes impact to the landscape compared to a greenfield corridor, the triple circuit requirement is unique to the WTPL project and has been excluded from this comparison. The adjustment is calculated based on the additional incremental cost to use triple circuit structures and string an additional three conductors (nine total, plus overhead shield wires), compared to double circuit structures consisting of six conductors and overhead shield wires.

Furthermore, the route defined through the Class EA process resulted in a centerline that requires more angle structures as well as crossings structures (over several other transmission lines, highways, multiple water crossings, etc). This drives a requirement for much taller and heavier structures. The corridor also parallels an existing energized line for the majority of the route, which will have an impact on construction productivity, compared to a completely greenfield route, as electrical safety clearances must be maintained. This non-linear routing situated adjacent an energized line, and the requirement for additional crossings are all a byproduct of the distinct features and significant level of developed infrastructure and geography in the region. These items are again specific to the Project and has been excluded in the comparison. This adjustment was calculated by determining the incremental cost for modifying construction methods to accommodate the project's unique constraints (e.g., the increased cost of manual stringing near energized lines compared to helicopter stringing, multiple shorter stringing operations with multiple lengthy setup times compared to longer continuous stringing operations with fewer setups), as well as the incremental cost of using taller and heavier angle structures and foundations (used for the many infrastructure crossings and centerline changes) compared to the cost of suspension structures and their associated smaller foundations.

The WTPL Project is both a double, and triple circuit 230kV/115kV transmission line build that will be constructed in a nominally 30m wide idle and re-used right of way. Typically, a double circuit 230kV transmission line would be constructed in a right of way that is nominally 46m wide. Designing for a narrower right-of-way allows Hydro One to re-use existing transmission line corridors in the area. This reduces the impact to the landscape and reduces real estate acquisition cost and the corresponding risks associated with greenfield real estate rights acquisition, but the confined right-of-way necessitates additional structures to constrain conductor swing within the right-of-way. The cost of these additional structures have therefore been excluded from the comparison. This adjustment is calculated by comparing the quantity of structures required for a more conventional greenfield 230kV 46m corridor relative the additional structures needed to constrain the conductor swing within a narrower right-of-way, which depends on the right of way width.

Hydro One provides that although real estate costs are excluded from the comparison provided in Table 5, the costs are reasonable as the real estate estimate for the WTPL Project is supported by a land value study completed by an independent third-party appraiser, and a contingency cost amount that is reserved for potential expropriation. Site-specific appraisals are currently underway. The land value study provides a reasonably accurate representation of anticipated land acquisition costs, which are considered to be within normal project cost variability. The value of the adjustment is limited to just the nominally 30m wide right-of-way and does not reflect what the costs would be if the larger transmission corridor 46m wide was secured for the full length of the line.

Adjustments were also made for the region topography that would impact construction, notably, the use of micropile foundations based on terrain characteristics along the corridor on the Power South Nepean Project. Similarly, an adjustment for the use of a line bypass required for the project-specific construction execution plans for the Woodstock Area Transmission Reinforcement, Power South Nepean, and Welland Thorold Power Line projects due to load/outage constraints.

The variances in the unadjusted per/km cost to execute these projects is also driven by the timing differences in the in-service date. Therefore, Table 5 has been adjusted to show comparable projects in 2029 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 5, the comparable projects demonstrate that the estimate for the WTPL Project is consistent with the cost to complete comparable transmission line works and is reasonable.

1 **Table 5 - Costs of Comparable Line Projects**

Project	**Guelph Area Transmission Refurbishment Project (Line Cost)**	**Power South Nepean Project (Line Cost)**	**Woodstock Area Reinforcement (Line Cost)**	**Welland Thorold Power Line (Line Cost)**
Circuit Operating Designation(s)	B5G, B6G	S7M and E34M	M32W/M31W plus K12/K7	Q24HM and Q29HM
Voltage	230 kV	230 kV	230 kV	230 kV
Structure Type	Steel Lattice and Steel Pole	Steel Lattice and Steel Pole	Steel Lattice and Steel Pole	Steel Lattice
Single or Double Circuit	Double	Double	Double	Double, Triple
Conductor	1443.7 kcmil ACSR/TW	997.2 kcmil ACSR/TW	1443.7 kcmil ACSR/TW	1433.6 kcmil ACSS/TW
Location	Southwest Ontario	Eastern Ontario	Southwest Ontario	Southwest Ontario
Project Surroundings	Urban Parallel to Hwy 6, multiple crossings - highway, roads	Urban-Rural Parallel to Hwy 416	Urban-Rural Parallel to Karn Rd	Urban, suburban, rural, industrial, multiple crossings – highway, roads, transmission lines, Welland Canal
In-Service Year	2016	2021	2012	2029
Estimate or Actual	Actual	Actual	Actual	Estimate
OEB-Approved Cost Estimate	$27.5M[7]	$58.8M[8]	$42.9M[9]	–
Total Cost	$23,500K	$51,276K	$35,600K	$234,900K
Less Adjustments:				
Real Estate	*$1,400K*	*$2,229K*	*$500K*	*$40,300K*
Micropile Foundation	*N/A*	*$6,730K*	*N/A*	*N/A*
Bypass	*N/A*	*$1,419K*	*$4,300K*	*$9,990K*
Triple Circuit	*N/A*	*N/A*	*N/A*	*$17,600K*
Adjacent Energized Line	*N/A*	*N/A*	*N/A*	*$9,300K*
Nonlinear Corridor	*N/A*	*N/A*	*N/A*	*$11,400K*
Taller/Larger/Heavier Structures	*N/A*	*N/A*	*N/A*	*$16,400K*
Constrained/Narrower RoW	*N/A*	*N/A*	*N/A*	*$41,400K*
Comparable Costs, before Escalation	$22,100K	$40,898K	$30,800K	$88,510K
Escalation Adjustment[10]	$10,147.7K	$13,153.0K	$18,494.0K	N/A
Total Adjusted Comparable Cost	$32,248K	$54,051K	$49,294K	$88,510K
Approximate Length	5.0 km	12.2 km	13.6 km	18.5 km
Unit Cost	**$6,450K/km**	**$4,430K/km**	**$3,625K/km**	**$4,784K/km**

[7] As per Section 92 leave to construct proceeding EB-2013-0053
[8] As per Section 92 leave to construct proceeding EB-2019-0077
[9] As per Section 92 leave to construct proceeding EB-2007-0027
[10] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

3.0 COSTS OF COMPARABLE PROJECTS – Transformer STATIONS

For station cost comparison purposes, Table 6 below shows the cost, construction, and technical comparisons of the proposed terminal station modifications at Crowland TS to three other recently in-serviced comparable projects.

- **St. Isidore TS:** Replaced existing two 230kV/44kV 28/38/47MVA transformers, and associated DESN station equipment for 4 feeders, at St. Isidore TS, with two new 230kV/44kV 50/66.7/83MVA transformers with DESN equipment for 5 feeders in a greenfield station area.
- **Minden TS:** Replaced existing two 230kV/44kV 42MVA transformers, and associated DESN station equipment for 4 feeders, at Minden TS, with two new 230kV/44kV 50/66.7/83MVA transformers with DESN equipment for 4 feeders in a greenfield station area.
- **Arnprior TS:** Replaced existing two 115kV/44kV 25/33/42MVA transformers, and associated DESN station equipment for 2 feeders, at Anrprior TS, with two new 115kV/44kV 25/33/42MVA transformers and DESN equipment for 2 feeders.

Unlike making a line comparison, where a per-kilometer cost can be derived, the same methodology and inferences for station work cannot always be achieved. There are several major differentiating factors, based on the unique site and station configuration, making individual station cost comparisons difficult. Notwithstanding that detail, the comparable projects selected are considered reasonable because they all include the replacement of an existing operational DESN.

For the purposes of the comparison, Hydro One has excluded the real estate costs from all comparable projects. Hydro One has also excluded the cost to remove the existing DESN station equipment, the cost to reconfigure feeder egress, the cost to clear the area for the new station of existing industrial infrastructure, the cost to modify remote station protections and control equipment, ground and geotechnical conditions. These costs are excluded from comparison as they are specific to the project site and are not broadly comparable.

Geotechnical conditions are validated based on a site-specific geotechnical investigation, which drive site-specific design and associated procurement and construction costs. Subsurface conditions and buried infrastructure are particular to the project site and differ greatly compared to other sites like greenfield farm fields, or other station sites.

Feeder egress modifications are particular to each site, feeder size, the number of feeders, overhead or underground arrangement for each feeder, as well as the routing of the feeders out of the station. This makes the cost associated with feeder egress modification specific to the site and difficult to compare, therefore these costs have been omitted from comparison. Similarly, Crowland TS has a larger 27.6kV yard, consisting of five to eight additional feeders compared to the other three stations. On average, the comparator stations have 4 feeders. Consequently, the cost of six additional feeders installed as part of Crowland TS has been omitted from the comparison to better align with comparable projects.

Furthermore, Table 6 has been adjusted to reflect the timing differences in the in-service date by showing comparable projects in 2029 dollars utilizing inflation values for future years consistent with the inflation parameters provided by the OEB.

When considering the adjusted comparable station costs in Table 6, the comparable projects demonstrate that the estimate costs for Crowland TS is consistent with the cost to complete comparable terminal station modification work and is reasonable.

Table 6 - Costs of Comparable Station Projects - Crowland TS

Project	St. Isidore TS (Station Cost)	Minden TS (Station Cost)	Arnprior TS (Station Cost)	Crowland TS (Station Cost)
Technical	Replace existing St Isidore TS with 230kV/44kV 50/83MVA DESN with 5 feeders	Replace existing Minden TS with 230kV/44kV 50/83MVA DESN with 4 feeders	Replace existing Arnprior TS with Greenfield 115kV/44kV 25/42MVA DESN with 2 feeders	Replace existing Crowland TS with 230kV/27.6kV DESN with 10 feeders
Location	Southeastern Ontario	Southeastern Ontario	Southeastern Ontario	Southwestern Ontario
Project Surroundings	Rural	Rural	Rural	Industrial/ Residential
Environmental Issues	None	None	None	None
In-Service Year	2019	2021	2023	2029
Estimate or Actual	**Actual**	**Actual**	**Actual**	Estimate
OEB-Approved Cost Estimate	$41, 947K[11]	$17,200K[12]	$14,200K[13]	–
Total Cost	**$34,114K**	**$42,273K**	**$36,766K**	**$76,500K**
Less Adjustments:				
Removal	*$217K*	*$1,546K*	*$382K*	*$1,500K*
Real Estate	*$29K*	*$27K*	*$9K*	*N/A*
Feeder Reconfiguration	*N/A*	*N/A*	*N/A*	*$4,500K*
Brownfield Site Clearing	*N/A*	*N/A*	*N/A*	*$3,300K*
Remote Stations	*N/A*	*N/A*	*N/A*	*$2,000K*
Ground Conditions	*N/A*	*$1,200K*	*$2,200K*	*$2,900K*
10 Feeders (6 Additional Feeders)	*N/A*	*N/A*	*N/A*	*$10,370K*
Comparable Costs, before escalation	**$33,869K**	**$39,499K**	**$34,174K**	**$51,930K**
Escalation Adjustment[14]	**$13,398K**	**$12,703K**	**$9,011K**	**N/A**
Total Adjusted Comparable Cost	**$47,267K**	**$52,202K**	**$43,184K**	**$51,930K**

[11] As per Section 92 leave to construct proceeding EB-2023-0360
[12] As per Cost of Service proceeding EB-2016-0160
[13] As per Rates Application EB-2021-0110
[14] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

CONNECTION PROJECTS REQUIRING NETWORK REINFORCEMENT

This is not a connection project. Facilities being upgraded 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

The Project costs, provided in **Exhibit B, Tab 7, Schedule 1**, will be included in the network and transformation connection pools for cost classification purposes. As discussed throughout the application, the costs that underpin this economic feasibility and rate impact assessment includes the new switching station that is required to achieve the full incremental load per the Final System Impact Assessment as provided in **Exhibit F, Tab 1, Schedule 1.**

A 25-year discounted cash flow analysis of the network pool work demonstrates that based on the estimated initial cost of $290.5 million, plus the assumed impact on the future capital cost allowance and Hydro One corporate income tax and approximately $11.2 million in annual incremental network revenue utilizing the 2025 UTR over a 25 year evaluation period, this project will have a negative net present value of $146.5 million as seen in Table 1 and 2.

A 25-year discounted cash flow analysis of the transformation connection pool work demonstrates that based on the estimated initial cost of $76.5 million, plus the assumed impact on the future capital cost allowance and Hydro One corporate income tax and approximately $5.9 million in annual incremental transformation connection revenue utilizing the 2025 UTR over a 25 year evaluation period, this project will have a negative net present value of $12.4 million as seen in Table 3 and 4.

2.0 COST RESPONSIBILITY

Network Pool

The Project will enable 180MW of supply capacity. This Project is not associated with a specific load increase or customer load application. As identified by the IESO[1], the purpose of the Project is to:

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

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

The current 115kV supply circuits to Crowland TS currently exceed a load security criterion. Transferring Crowland TS to the 230kV system alleviates the strain on the 115kV system by reducing the severity of the load security issue.

The transmission line that functionally serves as a line connection facility will be recovered through the network pool. The justification for doing so is that the building of the 230kV transmission system into the southern portion of the Niagara peninsula provides an opportunity to alleviate the strain on the 115kV transmission system. The 230kV transmission system provides enhanced reliability above what a 115kV transmission system supply provides and would be the first step in a long-term transition towards the elimination of the 115kV supply in the area. The building of the 230kV supply circuit will serve as a network benefit for the transmission system that is shared by all users as it would provide significant cost savings by eliminating or significantly deferring other

[1] Exhibit H, Tab 1, Schedule 1, Attachment 2.

investments (e.g., replacement of Crowland TS as is) and enabling additional load growth in the area as affirmed by the IESO in **Exhibit B, Tab 3, Schedule 1, Attachment 1.**

Transformation Connection Pool

The work being undertaken at Crowland TS continues to qualify as a transformation connection asset as the facility will continue to step down voltage from above 50kV to below 50kV after completion of the Project, albeit the station will convert from the existing 115kV/27.6kV station to a new 230kV/27.6kV station.

Welland Hydro will be responsible for the incremental costs associated with the increased station load capacity, representing the difference between rebuilding the existing 115kV 83 MVA station and constructing a new 230kV 125 MVA station.

However, based on the transformation connection pool discounted cash flow provided at Table 7 of this Schedule, Welland Hydro will not be required to make a capital contribution because forecast future revenues will offset the cost.

3.0 RATE IMPACT ASSESSMENT

The analysis of the network and transformation connection pool rate impacts has been carried out on the basis of Hydro One’s transmission revenue requirement for the year 2025 and the 2025 approved Ontario Transmission Rate Schedules. The network and transformation connection pool revenue requirements would be affected by the Project based on the project cost allocation.

Network Pool

Based on the total Project’s initial cost of $290.5 million and the associated network pool incremental cash flows, there will be a change in the network pool revenue requirement once the Project’s impacts are reflected in the transmission rate base at the projected in-service date of August 14, 2029. The 2025 OEB approved rate of $6.37 kW/month increases to $6.43 kW/month by the 3rd year then decreases to $6.41 kW/month in the 21st year onwards over a 25-year time horizon. The detailed analysis illustrating the calculation of the incremental network revenue and rate impact is provided in Table 5 and 6 below.

Transformation Connection Pool

Based on the total Project's initial cost of $76.5 million and the associated transformation pool incremental cash flows, there will be a change in the transformation pool revenue requirement once the Project's impacts are reflected in the transmission rate base at the projected in-service date of August 14, 2029. The 2025 OEB approved rate of $3.39 kW/month increases to $3.40 kW/month in the 3rd year then decreases back to $3.39 kW/month in the 19th year over a 25-year time horizon. The detailed analysis illustrating the calculation of the incremental transformation revenue and rate impact is provided in Table 7 and 8 below.

<u>Impact on Typical Residential Customer</u>

Based on the load forecast, initial capital costs and ongoing maintenance costs, adding the costs of the required facilities to the network and transformation connection pools will cause a $0.11 per month increase in a typical residential customer's rates under the Regulated Price Plan ("RPP"). The table below shows this result for a typical residential customer who is under the RPP, utilizing the maximum impact by rate pool, regardless of year.

A. Typical monthly bill	$153.95 per month
B. Transmission component of monthly bill	$17.27 per month
C. Line Connection Pool share of Transmission component	$1.6 per month
D. Transformation Connection Pool share of Transmission component	$5.42 per month
E. Network Connection Pool share of Transmission component	$10.25 per month
F. Impact on Line Connection Pool Provincial Uniform Rates	0.00%
G. Impact on Transformation Connection Pool Provincial Uniform Rates	0.29%
H. Impact on Network Connection Pool Provincial Uniform Rates	0.94%
I. Increase in Transmission costs for typical monthly bill (D x G + E x H)	$0.11 per month or $1.34 per year
J. Net increase on typical residential customer bill (I / A)	0.07%

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Table 1 - Net Present Value, Network Pool page 1

			In-Service Date	<------- Project year ended - annualized from In-Service Date -------->											
		Month	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14
		Year	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast															
Load Forecast (MW)				145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Tariff Applied ($/kW/Month)				6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37
Incremental Revenue - $M				11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
Removal Costs - $M			0.0												
On-going OM&A Costs - $M			0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Municipal Tax - $M				(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)
Net Revenue/(Costs) before taxes - $M			0.0	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Income Taxes			0.0	0.2	2.9	2.5	2.1	1.7	1.4	1.1	0.8	0.5	0.3	0.0	(0.2)
Operating Cash Flow (after taxes) - $M			0.0	10.3	13.0	12.6	12.2	11.8	11.4	11.1	10.8	10.6	10.3	10.1	9.9
		Cumulative PV @ 5.65%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**142.4**	**0.0**	**10.0**	**12.0**	**11.0**	**10.0**	**9.2**	**8.4**	**7.8**	**7.2**	**6.6**	**6.1**	**5.7**	**5.3**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(262.5)												
- Overheads			(7.7)												
- AFUDC			(20.3)												
Total upfront capital expenditures			**(290.5)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(290.5)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**1.6**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	**(B)**	**(288.9)**	**(288.9)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(146.5)**	**(288.9)**	**(278.8)**	**(266.9)**	**(255.9)**	**(245.9)**	**(236.7)**	**(228.2)**	**(220.4)**	**(213.3)**	**(206.6)**	**(200.5)**	**(194.8)**	**(189.6)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.65%**

		$M
PV Incremental Revenue		151.5
PV OM&A Costs		(1.7)
PV Municipal Tax		(13.0)
PV Income Taxes		(36.3)
PV CCA Tax Shield		43.4
PV Capital - Upfront	(290.5)	
Add: PV **Capital Contribution**	**0.0**	(290.5)
PV Capital - On-going		0.0
PV Working Capital		(0.0)
PV Surplus / (Shortfall)		**(146.5)**
Profitability Index*		**0.5**

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

Other Assumptions

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

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

	<------- Project year ended - annualized from In-Service Date -------->												
Month	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14
Year	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast													
Load Forecast (MW)	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Tariff Applied ($/kW/Month)	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37
Incremental Revenue - $M	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
Removal Costs - $M													
On-going OM&A Costs - $M	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Municipal Tax - $M	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)
Net Revenue/(Costs) before taxes - $M	10.1	10.1	10.1	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Income Taxes	(0.4)	(0.5)	(0.7)	(0.8)	(1.0)	(1.1)	(1.2)	(1.3)	(1.4)	(1.5)	(1.6)	(1.7)	(1.8)
Operating Cash Flow (after taxes) - $M	9.7	9.5	9.4	9.2	9.1	8.9	8.8	8.7	8.6	8.5	8.4	8.3	8.3
PV Operating Cash Flow (after taxes) - $M (A)	**4.9**	**4.5**	**4.2**	**3.9**	**3.7**	**3.4**	**3.2**	**3.0**	**2.8**	**2.6**	**2.4**	**2.3**	**2.2**
Capital Expenditures - $M													
Upfront - capital cost before overheads & AFUDC													
- Overheads													
- AFUDC													
Total upfront capital expenditures													
On-going capital expenditures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures													
Total capital expenditures - $M													
Capital Expenditures - $M													
PV CCA Residual Tax Shield - $M													
PV Working Capital - $M													
PV Capital (after taxes) - $M (B)													
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)	**(184.7)**	**(180.2)**	**(176.0)**	**(172.0)**	**(168.4)**	**(165.0)**	**(161.8)**	**(158.8)**	**(156.0)**	**(153.4)**	**(151.0)**	**(148.7)**	**(146.5)**

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

			In-Service Date	<-------		Project year ended - annualized from In-Service Date			-------->						
		Month	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14
		Year	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast															
Load Forecast (MW)				145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Tariff Applied ($/kW/Month)				3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39
Incremental Revenue - $M				5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Removal Costs - $M			0.0												
On-going OM&A Costs - $M			0.0	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
Municipal Tax - $M				(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Net Revenue/(Costs) before taxes - $M			0.0	5.4	5.4	5.4	5.4	5.4	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Income Taxes			0.0	(0.6)	0.1	(0.0)	(0.1)	(0.2)	(0.3)	(0.3)	(0.4)	(0.5)	(0.6)	(0.6)	(0.7)
Operating Cash Flow (after taxes) - $M			0.0	4.8	5.6	5.4	5.3	5.2	4.9	4.8	4.8	4.7	4.6	4.5	4.5
		Cumulative PV @ 5.65%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**63.7**	**0.0**	**4.7**	**5.1**	**4.7**	**4.4**	**4.1**	**3.6**	**3.4**	**3.1**	**2.9**	**2.7**	**2.6**	**2.4**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(67.8)												
- Overheads			(1.4)												
- AFUDC			(7.3)												
Total upfront capital expenditures			**(76.5)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(76.5)**												
Capital Expenditures - $M															
PV CCA Residual Tax Shield - $M			**0.4**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	**(B)**	**(76.1)**	**(76.1)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(12.4)**	**(76.1)**	**(71.4)**	**(66.3)**	**(61.6)**	**(57.2)**	**(53.2)**	**(49.5)**	**(46.1)**	**(43.0)**	**(40.1)**	**(37.3)**	**(34.8)**	**(32.4)**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**
Discount Rate - %		**5.65%**
		$M
PV Incremental Revenue		80.6
PV OM&A Costs		(6.2)
PV Municipal Tax		(3.4)
PV Income Taxes		(18.8)
PV CCA Tax Shield		11.9
PV Capital - Upfront	(76.5)	
Add: PV **Capital Contribution**	**0.0**	(76.5)
PV Capital - On-going		0.0
PV Working Capital		(0.0)
PV Surplus / (Shortfall)		(12.4)
Profitability Index*		**0.8**

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

Other Assumptions

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

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

	<------- Project year ended - annualized from In-Service Date -------->												
Month	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14	Aug-14
Year	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast													
Load Forecast (MW)	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8	145.8
Tariff Applied ($/kW/Month)	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39
Incremental Revenue - $M	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Removal Costs - $M													
On-going OM&A Costs - $M	(0.5)	(0.5)	(0.5)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)
Municipal Tax - $M	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Net Revenue/(Costs) before taxes - $M	5.2	5.2	5.2	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Income Taxes	(0.8)	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)	(1.0)	(1.0)	(1.0)	(1.0)	(1.1)	(1.1)	(1.1)
Operating Cash Flow (after taxes) - $M	4.4	4.4	4.3	4.2	4.2	4.1	4.1	4.1	4.0	4.0	4.0	4.0	3.9
PV Operating Cash Flow (after taxes) - $M (A)	**2.2**	**2.1**	**2.0**	**1.8**	**1.7**	**1.6**	**1.5**	**1.4**	**1.3**	**1.2**	**1.2**	**1.1**	**1.0**
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)	**(30.2)**	**(28.1)**	**(26.1)**	**(24.3)**	**(22.6)**	**(21.1)**	**(19.6)**	**(18.2)**	**(16.9)**	**(15.7)**	**(14.5)**	**(13.4)**	**(12.4)**

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

Welland Thorold Power Line		Project YE 14-Aug 2030	14-Aug 2031	14-Aug 2032	14-Aug 2033	14-Aug 2034	14-Aug 2035	14-Aug 2036	14-Aug 2037	14-Aug 2038	14-Aug 2039	14-Aug 2040	14-Aug 2041
Calculation of Incremental Revenue Requirement ($ millions)		1	2	3	4	5	6	7	8	9	10	11	12
In-service date	14-Aug-29												
Capital Cost	290.5												
Less: Capital Contribution Required	-												
Net Project Capital Cost	290.5												
Average Rate Base		142.4	281.9	276.1	270.3	264.6	258.8	253.1	247.3	241.5	235.8	230.0	224.3
Incremental OM&A Costs		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Grants in Lieu of Municipal tax		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Depreciation		5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Interest and Return on Rate Base		9.0	17.9	17.5	17.1	16.8	16.4	16.1	15.7	15.3	15.0	14.6	14.2
Income Tax Provision		0.1	(1.7)	(1.2)	(0.7)	(0.3)	0.1	0.4	0.7	1.0	1.3	1.5	1.7
REVENUE REQUIREMENT PRE-TAX		**15.9**	**23.0**	**23.1**	**23.2**	**23.3**	**23.3**	**23.3**	**23.3**	**23.2**	**23.1**	**22.9**	**22.8**
Incremental Revenue		11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
SUFFICIENCY/(DEFICIENCY)		**(4.7)**	**(11.8)**	**(12.0)**	**(12.1)**	**(12.1)**	**(12.2)**	**(12.2)**	**(12.1)**	**(12.0)**	**(11.9)**	**(11.8)**	**(11.6)**
	Base Year												
Network Pool Revenue Requirement including sufficiency/(deficiency)	1,497	1,513	1,520	1,520	1,521	1,521	1,521	1,521	1,521	1,521	1,520	1,520	1,520
Network MW	235	237	237	237	237	237	237	237	237	237	237	237	237
Network Pool Rate ($/kw/month)	6.37	6.39	6.42	6.43	6.43	6.43	6.43	6.43	6.43	6.43	6.42	6.42	6.42
Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year		0.02	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05
RATE IMPACT relative to base year		**0.31%**	**0.78%**	**0.94%**	**0.94%**	**0.94%**	**0.94%**	**0.94%**	**0.94%**	**0.94%**	**0.78%**	**0.78%**	**0.78%**

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

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

Welland Thorold Power Line		14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug	14-Aug
		2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
Calculation of Incremental Revenue Requirement ($ millions)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	14-Aug-29													
Capital Cost	290.5													
Less: Capital Contribution Required	-													
Net Project Capital Cost	290.5													
Average Rate Base		218.5	212.7	207.0	201.2	195.5	189.7	183.9	178.2	172.4	166.7	160.9	155.1	149.4
Incremental OM&A Costs		0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Grants in Lieu of Municipal tax		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Depreciation		5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Interest and Return on Rate Base		13.9	13.5	13.1	12.8	12.4	12.0	11.7	11.3	10.9	10.6	10.2	9.8	9.5
Income Tax Provision		1.9	2.0	2.2	2.3	2.4	2.5	2.6	2.7	2.7	2.8	2.8	2.8	2.9
REVENUE REQUIREMENT PRE-TAX		**22.6**	**22.4**	**22.2**	**22.0**	**21.7**	**21.4**	**21.1**	**20.9**	**20.5**	**20.2**	**19.9**	**19.6**	**19.2**
Incremental Revenue		11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
SUFFICIENCY/(DEFICIENCY)		**(11.4)**	**(11.2)**	**(11.0)**	**(10.8)**	**(10.5)**	**(10.3)**	**(10.0)**	**(9.7)**	**(9.4)**	**(9.1)**	**(8.7)**	**(8.4)**	**(8.1)**
	Base Year													
Network Pool Revenue Requirement including sufficiency/(deficiency)	1,497	1,520	1,520	1,519	1,519	1,519	1,519	1,518	1,518	1,518	1,518	1,517	1,517	1,517
Network MW	235	237	237	237	237	237	237	237	237	237	237	237	237	237
Network Pool Rate ($/kw/month)	6.37	6.42	6.42	6.42	6.42	6.42	6.42	6.42	6.42	6.41	6.41	6.41	6.41	6.41
Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04
RATE IMPACT relative to base year		**0.78%**	**0.78%**	**0.78%**	**0.78%**	**0.78%**	**0.78%**	**0.78%**	**0.78%**	**0.63%**	**0.63%**	**0.63%**	**0.63%**	**0.63%**

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

Welland Thorold Power Line		Project YE 14-Aug 2030	14-Aug 2031	14-Aug 2032	14-Aug 2033	14-Aug 2034	14-Aug 2035	14-Aug 2036	14-Aug 2037	14-Aug 2038	14-Aug 2039	14-Aug 2040	14-Aug 2041
Calculation of Incremental Revenue Requirement ($ millions)		1	2	3	4	5	6	7	8	9	10	11	12
In-service date	14-Aug-29												
Capital Cost	76.5												
Less: Capital Contribution Required	-												
Net Project Capital Cost	76.5												
Average Rate Base		37.5	74.2	72.7	71.1	69.6	68.1	66.6	65.0	63.5	62.0	60.4	58.9
Incremental OM&A Costs		0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Grants in Lieu of Municipal tax		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Depreciation		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Interest and Return on Rate Base		2.4	4.7	4.6	4.5	4.4	4.3	4.2	4.1	4.0	3.9	3.8	3.7
Income Tax Provision		(0.0)	(0.6)	(0.4)	(0.3)	(0.2)	(0.0)	0.1	0.1	0.2	0.3	0.4	0.4
REVENUE REQUIREMENT PRE-TAX		**4.4**	**6.2**	**6.2**	**6.3**	**6.3**	**6.6**	**6.6**	**6.6**	**6.5**	**6.5**	**6.5**	**6.4**
Incremental Revenue		5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
SUFFICIENCY/(DEFICIENCY)		**1.6**	**(0.2)**	**(0.3)**	**(0.3)**	**(0.4)**	**(0.6)**	**(0.6)**	**(0.6)**	**(0.6)**	**(0.6)**	**(0.5)**	**(0.5)**
	Base Year												
Transformation Pool Revenue Requirement including sufficiency/(deficiency)	650	654	656	656	656	656	657	657	657	657	657	657	657
Transformation MW	192	193	193	193	193	193	193	193	193	193	193	193	193
Transformation Pool Rate ($/kw/month)	3.39	3.39	3.39	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40
Increase/(Decrease) in Transformation Pool Rate ($/kw/month), relative to base year		0.00	0.00	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		**0.00%**	**0.00%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**

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

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

Welland Thorold Power Line		**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**	**14-Aug**
		2042	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**
Calculation of Incremental Revenue Requirement ($ millions)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	14-Aug-29													
Capital Cost	76.5													
Less: Capital Contribution Required	-													
Net Project Capital Cost	76.5													
Average Rate Base		57.4	55.8	54.3	52.8	51.3	49.7	48.2	46.7	45.1	43.6	42.1	40.5	39.0
Incremental OM&A Costs		0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Grants in Lieu of Municipal tax		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Depreciation		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Interest and Return on Rate Base		3.6	3.5	3.4	3.3	3.3	3.2	3.1	3.0	2.9	2.8	2.7	2.6	2.5
Income Tax Provision		0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8
REVENUE REQUIREMENT PRE-TAX		**6.4**	**6.4**	**6.3**	**6.4**	**6.3**	**6.2**	**6.2**	**6.1**	**6.0**	**5.9**	**5.8**	**5.7**	**5.7**
Incremental Revenue		5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
SUFFICIENCY/(DEFICIENCY)		**(0.5)**	**(0.4)**	**(0.4)**	**(0.4)**	**(0.4)**	**(0.3)**	**(0.2)**	**(0.1)**	**(0.1)**	**0.0**	**0.1**	**0.2**	**0.3**
	Base Year													
Transformation Pool Revenue Requirement including sufficiency/(deficiency)	650	656	656	656	656	656	656	656	656	656	656	656	656	656
Transformation MW	192	193	193	193	193	193	193	193	193	193	193	193	193	193
Transformation Pool Rate ($/kw/month)	3.39	3.40	3.40	3.40	3.40	3.40	3.40	3.39	3.39	3.39	3.39	3.39	3.39	3.39
Increase/(Decrease) in Transformation Pool Rate ($/kw/month), relative to base year		0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RATE IMPACT relative to base year		**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**

1 **Table 9 - DCF Assumption**

Hydro One Networks -- Transmission Connection Economic Evaluation Model
2025 Parameters and Assumptions

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

Monthly Rate ($ per kW)	
Network	**6.37**
Transformation	**3.39**
Line	**1.00**

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:	2025	**15.00%**	Current rate
Ontario corporation income tax - % of taxable income:	2025	**11.50%**	Current rate

Capital Cost Allowance Rate:

Class 47 costs	2025	**8%**	Current rate
Easement rights	2025	**5%**	
Decision Support defined costs (2)	2025	**0%**	
Decision Support defined costs (3)	2025	**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

REVENUE REQUIREMENT AND TRANSMISSION SYSTEM PLAN INFORMATION

The need for station work contemplated as a subset of the Project was identified in the TSP included in Hydro One's most recent Joint Rate Filing Application, EB-2021-0110 at Exhibit B, Tab 2, Schedule 1 Section 2.11 and more specifically discussed in Investment Summary Document ("ISD") T-SR-03.09 , provided as **Attachment 1 of this Schedule**.

Hydro One recognizes that there is a cost difference between the forecast cost referenced in ISD T-SR-03.09 of $35.8 million[1] which was underpinned by a sustainment scope of station work at Crowland TS and the cost to execute the total Project ($311.4 million) filed in this Application at **Exhibit B, Tab 7, Schedule 1** that includes both line and station. The difference is predominantly driven by a significant change in project scope to address new regional system needs defined through the IESO regional planning process as documented at **Attachment 1** and **Attachment 2 of Exhibit H, Tab 1, Schedule 1.**

Focusing on the station component, as noted, ISD T-SR-03.09 was initially planned to focus strictly on sustainment work required at Crowland TS. The forecast investment as planned at the time of the last OEB-approved revenue requirement involved the replacement of transformers, the associated protection equipment and reconfiguration and replacement of various 115 kV switches. Conversely, to address the needs defined by the IESO, the scope of the Project will now convert the existing station from 115 kV to 230 kV to enable connection to the new 230 kV transmission line. As more completely described in **Exhibit C, Tab 1, Schedule 1,** the station scope of the Project will include, but not limited to, the construction of a new 230kV/27.6kV DESN Station with two (2) new 230kV/27.6kV 75/100MVA transformers, as well as protection, control, and

[1] This forecast cost is from the prefiled evidence in OEB docket EB-2021-0110 and does not consider the specific impacts of inflation increases and settlement reductions noted in the OEB-approved Hydro One JRAP Settlement Proposal.

telecommunications modifications at three remote stations to accommodate the new 230kV line and Crowland TS.

The original station forecast cost $35.8M is therefore not comparable to the current station forecast cost of $76.5M. [2]

The ISD for the Crowland TS terminal station modification work was also predicated upon a less defined project scope. The ISD estimate at best reflects an AACE Class 4 estimate with an upper range of +50%. Conversely, the current estimate for Crowland TS is based upon an AACE Class 3 estimate range of +20/-15% as described in **Exhibit B, Tab 7, Schedule 1.**

As also described in **Exhibit B, Tab 7, Schedule 1**, the ISD forecast cost does not reflect cost pressures that have arose in the industry, since the ISD forecast cost was developed, that have impacted costs for infrastructure projects, e.g., COVID-19, global supply chain issues and escalating inflation levels. For example, the OEB has recently released the 2026 Inflation Factor to be used to set rates for electricity transmitters for 2026. The OEB has calculated the 2026 inflation factor for electricity transmitters to be 3.5%[3]. Inflationary cost pressures alone have increased by approximately 1.8 times since the filing of the ISD in 2021, where the 2021 inflation factor was 2.0% for electricity transmitters.

With respect to the transmission line costs, these costs are anticipated to be captured and tracked in the Affiliate Transmission Partnership Regulatory Deferral and Variance account (“ATP Account”), which will be disposed of during a future rate hearing for the New Partnership, created for shared ownership of the transmission line component of the Project. Hydro One notified the OEB on July 9th, 2025, of the inclusion of WTPL in the ATP

[2] Hydro One notes that the current station estimate excludes Crowland SS which is currently based upon an AACE Class 5 estimate range of -50/+100% as described in Exhibit B, Tab 7, Schedule 1. The switching station is a new requirement that was defined during the final SIA. The forecast cost for that specific station work is not as mature as the balance of the forecast costs and treated as a separate project and estimate.
[3] OEB 2026 Inflation Parameters, June 11, 2025

Account, provided as **Attachment 2 of this Schedule**. Costs associated with the line component of the Project have never been considered in Hydro One's revenue requirement.

All the above items describe why the forecast capital cost of the Project has increased relative to the ISD.

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T-SR-03	**TRANSMISSION STATION RENEWAL - CONNECTION STATIONS**
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	334.5	357.7	350.1	406.5	428.6	1,877.3

Summary:

This investment involves the replacement of critical transmission station assets at connection stations that have deteriorated to poor condition, thereby posing reliability, safety and environmental risks. The primary triggers of the investment are high risk of asset failures, deteriorated condition and need to maintain transmission system and customer supply reliability. The investment is expected to mitigate the risk of reduced supply reliability and customer outages due to equipment failures.

A. OVERVIEW

Connection stations are transmission stations serving Local Distribution Companies (LDCs) and large industrial customers. The LDCs, in turn, serve Ontario's residential, commercial, institutional and small industrial end-users. Connection stations are connected to the network stations through 230kV and 115kV high-voltage lines and serve customers at distribution system voltage via 44kV, 27.6kV and 13.8kV feeders. The Transmission Station Renewal – Connection Stations investment (the "Investment") manages asset-failure related risks to stations performance and operational effectiveness with the replacement of key station assets that have been verified to be in poor condition. The Investment involves a series of individual investments and includes the replacement of multiple assets within a particular station. The scope of each investment comprising the Investment includes transformers, breakers, switchgear, and protection and control systems. Investments may also include other station assets, such as instrument transformers, disconnect switches and other ancillary equipment, as and where required. The list of stations and details for each individual investment are provided in **Appendix "A"** below.

Since 2014, Hydro One successfully utilized an integrated approach to station asset management where prudent. In particular, the integrated approach allows Hydro One to replace multiple key transmission assets, such as transformer, breakers, switchgear and protection and control equipment, within a transmission station that have been confirmed through condition assessment to be in poor condition. The integrated approach is primarily driven by the complexities of transmission stations, outage scheduling and the extended lead timelines required to replace deteriorated assets. By employing the integrated approach, Hydro One can complete the necessary asset replacements at a particular station at once as opposed to requiring multiple visits to replace individual assets which would result in re-engineering, repeated construction mobilization, and increased planned outages coordination at the same work location within a small time period. In a lot of instances, initiating multiple projects at a single station is simply not feasible. When transmission stations are reviewed and analyzed by transmission planners, there is an opportunity to review transmission stations for operational improvements and station right sizing for customers. This approach allows Hydro One to consult with customers to ensure refurbished transmission stations meet the needs of Hydro One customers. Examples include connection stations being rebuilt at a different supply voltage to support LDCs future plans or changing the number of transformers in the transmission station due to changes in customer needs.

Within each connection station, there are the following critical transmission assets: (i) step-down power transformers that convert higher transmission level voltages to lower distribution level voltages, (ii) circuit breakers and protection systems that protect the transmission station assets, customer equipment, and reduce outages, (iii) switchgear that facilitates the distribution of power to the downstream distribution network. Critical transmission station assets degrade over time. Hydro One does not run its transmission station assets to failure given their criticality to the integrity of the transmission system and the significant reliability, safety and environmental impact associated with their failures. Once an asset is confirmed to be in poor condition, replacement options are assessed.

Hydro One's connection stations provide the electrical energy necessary to power the provincial economy and meet society's daily needs. The main customers served at connection stations are LDCs and large industrial customers. The LDCs, in turn, serve Ontario's residential, commercial, institutional and small industrial end-users. Hydro One actively works with these customers LDC and large industrial customers to understand their needs and preferences. Through customer engagement activities, Hydro One's customers expressed strong support for the replacement of aging and deteriorating transmission station assets in order to maintain the overall health of transmission system.

To mitigate risks associated with poor condition assets, Hydro One evaluated several alternatives, as further described below, and concluded that continued targeted replacement of poor condition connection station assets is the most prudent alternative. To optimize the amount of risk mitigated in the pacing of investments, Hydro One prioritizes investments based on asset demographics, condition, performance, environmental and safety concerns, customers, and load served.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

The Investment focuses on the replacement of multiple transmission station assets that facilitate power transformation from a high transmission voltage to a lower distribution voltage. The Investment utilizes a bundled approach that targets multiple assets within a connection station confirmed to be in poor condition. Operating assets that are in poor condition pose an increased risk of failure or risk of failing to execute operations as intended. Transformers may catch fire resulting in extensive damage and oil spilling on and off-site into the neighbouring environment. Breakers may fail to operate (open) when needed, as they are intended to, or they may experience insulation failure leading to internal arcing during operation, causing irreparable damage. Failures to critical assets may result in damage to connected equipment, impacts to system stability, interruptions to customer delivery points with significant durations, employee and public safety risks and environmental impacts.

Failures of critical assets at a connection station may have serious consequences as they may partially or entirely interrupt power flow to load customers as well as constrain embedded generation on the distribution network connected to a connection station. Under normal operating conditions, a failure of a single asset at a connection station will usually not result in an extended load interruption due to the standard design redundancy of Hydro One's transmission connection stations. However, as discussed in Section 2.2, even when there is no customer interruption, forced outages can have other impacts on Hydro One's transmission system including decreased redundancy, increased wear and tear on other assets, and cancellation or rescheduling of planned outages for maintenance and replacement work. Furthermore, at the majority of connection stations, a significant proportion of station load may be 'stranded', meaning the load cannot be immediately transferred to another station or transferred within the distribution system. A failure at a vulnerable station with stranded load would result in extended power outages until an emergency measure is implemented.

Leaving poor condition transmission station assets in-service, such as oil-filled transformers, oil-filled circuit breakers and gas-filled circuit breakers, increases environmental and safety risks. Environmental risks include oil leaks and gas leaks. As transformers and circuit breakers age and deteriorate in condition, one issue that can materialize is oil and gas leaks. Deterioration of gasket and O-rings results in oil leaks from oil-filled transformers and circuit breakers and in gas leaks from SF6 gas-filled circuit breakers. When transformers and breakers are replaced, Hydro One follows the latest environmental standards to ensure oil leaks will be contained. Leaving poor condition transmission station assets in-service also increases the risk of catastrophic failures, which poses a safety risk for Hydro One staff and the public. Oil-filled equipment may explode resulting in fires, which may further damage surrounding equipment and injure personnel.

An example of a catastrophic failure is the 2018 Finch T2 catastrophic failure that resulted in three days of fires, within the connection station, before being declared extinguished. As a result of the firefighting effort, transformer oil mixed with water was discharged into the environment. Hydro One environmental staff and emergency spill response were required to manage the oil spill and complete the oil clean-up. The failure event ultimately affected the entire connection station and resulted in six multi-circuit delivery point interruptions with a total interruption duration of one and half days (i.e. 2,234 minutes).

The condition of transformers, breakers, and the age of protection and control systems are the leading indicators of the assets' performance that may eventually lead to catastrophic events, as the one described above. Given the criticality of transmission assets, Hydro One does not run them to failure. Asset deterioration is not reversible and cannot be stopped. Hydro One has a significant amount of assets that have been verified to be in poor condition. In addition, there is a large population of transmission assets that are in fair condition, meaning that there is some form of deterioration. This population of assets will eventually start migrating to the poor condition category, as the deterioration is not reversible. Key station assets demographics and condition are further described below.

TRANSFORMER CONDITION – CONNECTION STATIONS

As discussed in Section 2.2, transformer condition is a leading indicator of performance and a main driver for replacement. Where feasible, Hydro One maximizes the life of poor condition transformers by undertaking certain remedial actions. However, this solution is temporary in nature and requires ongoing monitoring. Based on Hydro One's experience, these transformers will have to be replaced in the near future.

Transformer condition is determined by industry standard diagnostic testing which includes routine transformer oil testing and other maintenance examinations. Hydro One retained a third party expert, EPRI, to provide an independent assessment of the condition of the transformers that Hydro One determined to be in poor condition. EPRI used its PTX Software to examine the condition of the transformer's main tank insulating oil condition. EPRI's analysis confirmed the degraded condition of most of these poor condition transformers. There are also transformers that EPRI was not able to validate based on main tank oil sampling because Hydro One primarily selected those transformers for replacement based on factors other than main tank oil results, e.g. leaks, tap changer issues, cooling system issues, etc. Further detail in relation to EPRI's study can be found in TSP Section 2.3.

The predominant indicator of transformer condition is insulation deterioration, which occurs as a function of time and operating temperature and is irreversible. Power transformer insulation consists of both oil and cellulose (paper/pressboard) that degrade over time. While the transformer oil can be drained and refilled, the cellulose layer of insulation cannot be replaced. Once the cellulose layer has aged and degraded, the transformer requires replacement.

Transformer condition can be impacted by several factors including loading history, age, environmental condition and history of outages or other issues. If a deteriorated transformer is carrying a higher load, it is likely to deteriorate faster than if it carries a lower load. A transformer's load can depend on a station design, and it may temporarily have a higher load if it is carrying the load of another transformer that is currently experiencing an outage. In a forced outage at a station with two transformers, the remaining transformer (which is likely the same age and has been subjected to similar environmental exposures and loading as the failed unit) would be required to bear the full load and thus undergo further condition deterioration as a result.

By operating a large number of poor condition transformers, there is an increase in system reliability risk as this equipment tends to have a higher probability of failure. As illustrated in Figure 1 below, assessment of the connection station transformer fleet's condition results shows that approximately 152 units (26%) are rated poor condition. There are another 63 units (11%) in fair condition that exhibit some form of deterioration. Given that deterioration cannot be stopped or reversed, this population of transformers will start migrating to the poor condition category.

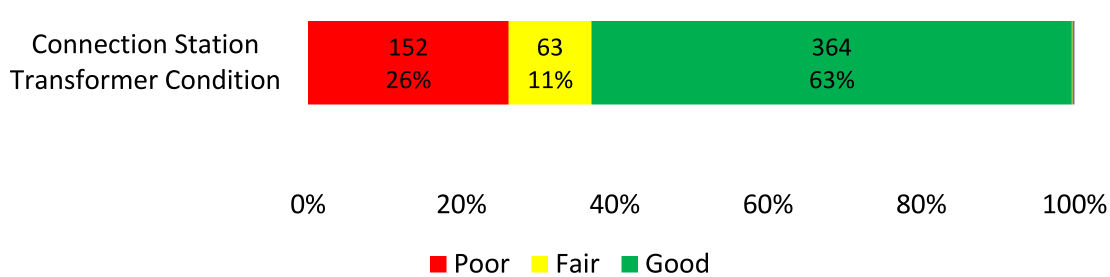

Figure 1: Condition Summary of Connection Station Transformer Fleet

BREAKER CONDITION – CONNECTION STATIONS

Similar to transformers, breaker condition is a leading indicator of expected performance. Poor condition breakers can ultimately result in outages to severely impact system stability, the operations of other connected equipment, and employee and public safety. Asset condition is determined through preventive maintenance including diagnostic testing and inspections and is one of the major drivers for breaker replacement as part of the Investment.

As discussed in TSP Section 2.2, circuit breakers use a variety of interrupting mediums including oil, air and SF6 gas. In the case of air and SF6, the interrupting mediums are kept at high pressure to effectively quench electric arcs during breaker operation. As breakers age their O-rings and gaskets slowly degrade causing the oil, air or SF6 gas to leak out and lower the breaker's pressure. Concurrently, leaks create a path for moisture ingress. Either condition (lower pressure or moisture ingress) reduces the dielectric strength in the breaker which reduces its arc quenching capability and increases the potential for internal flashover, which could lead to an explosive failure of the breaker.

A large number of the breakers in Hydro One's fleet contain PCBs. As of December 2020, 420 breakers that were manufactured pre-1985 require PCB remediation work including bushing retro-filling (i.e., putting in new PCB free oil to lower the PCB ppm concentration) or replacements to meet the PCB Regulation requirements.

SF_6 is a common and effective dielectric medium used in a large portion of the breaker fleet. Some model types have known issues with leaks, for example the medium voltage SP breakers (there are a total of 208 SP breakers in the Hydro One fleet). SP breakers have a known leak point on the bushing flange for which there is a repair procedure, but there is a subset of the SP breaker population (about 5% identified so far) for which these repairs are not effective, thereby requiring replacement.

Some of Hydro One's breakers (approximately 143, or 3% of the overall fleet) are no longer supported by vendors and aftermarket parts are no longer available or are costly to acquire or fabricate. This is a significant risk factor to some first generation SF6 GIS circuit breakers and most types of oil circuit breakers. Where parts are difficult to procure, specific units are replaced so the decommissioned devices can serve as strategic spares for the remaining in-service fleet, but that is not feasible for approximately 3% of the overall fleet.

Similar to transformers, operating a large number of the circuit breaker fleet that is poor condition increases system reliability risk as this equipment tends to have a worse performance and higher probability of failure. The assessment of the connection station breakers condition shows that approximately 401 (11%) are rated poor condition, as illustrated in Figure 3. Another 1203 (36%) of connection station breakers are in fair condition, exhibiting some form of deterioration.

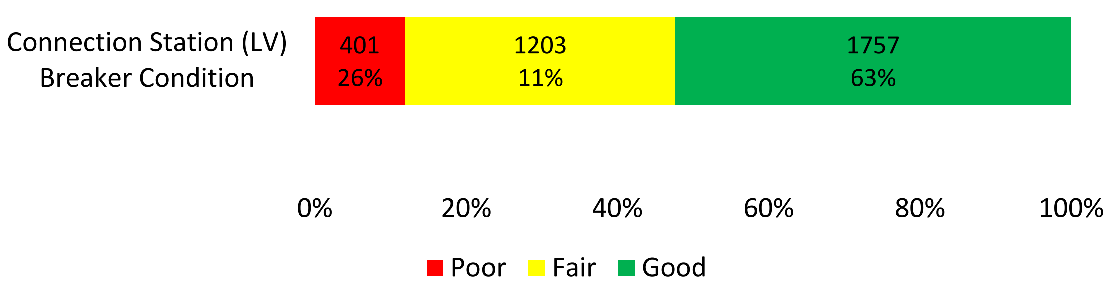

Figure 2: Condition Summary of MV Breakers Fleet

Hydro One's approach with respect to the replacement of breakers is to target specific breakers based on poor condition that pose system risks, as well as to steadily pace investments driven by obsolescence caused by reduced vendor support for aged product lines.

Table 1 below provides a summary of reasons and need for asset replacement based on the breaker type.

Table 1 - Reasons for Breaker Replacement by Breaker Type

Type of Breaker	Reason for Replacement
Oil Breaker	• Condition and reliability concerns • Obsolescence due to lack of vendor support and unavailability of maintenance parts • Non-compliance with current system operating ratings • PCB regulatory compliance • Current rating changes
Air Blast Breakers	• Significant negative impact on outage frequency • Deteriorating condition and performance • obsolescence due to lack of vendor support and unavailability of maintenance parts • Elimination of high maintenance costs
SF6 Breakers	• Condition and reliability concerns • Obsolescence due to lack of vendor support and unavailability of maintenance parts • SF6 emissions • Current Rating changes
GIS Breakers	• Reliability concerns • Obsolescence due to lack of vendor support and unavailability of maintenance parts • SF6 emissions
Metalclad	• Arc flash hazards • Obsolescence due to lack of vendor support and unavailability of maintenance parts
Vacuum	• Obsolescence due to lack of vendor support and unavailability of maintenance parts

Hydro One's plan prioritizes breaker replacements based on poor condition, obsolescence, vendor support availability, environmental footprint, system criticality and safety risk.

To assess the changes in short circuit levels due to system upgrades and new or modified customer connection facilities, Hydro One performs project-specific short circuit studies and identifies any required breaker upgrades as part of the IESO Connection Assessment and Approval (CAA) process. Where short circuit level ratings are exceeded, breakers need to be upgraded to higher short circuit rating, since operating beyond the nameplate rating can cause the breaker to fail.

Replacing breakers that are based on obsolete technology eliminates maintenance activities that are no longer required for modern breakers. Examples include the elimination of ABCBs and the replacement of pneumatic mechanisms with simpler mechanisms.

Where spare parts are difficult to obtain or are no longer commercially available, sustainment of associated breaker fleets will be achieved by harvesting subcomponents from decommissioned units until the remaining fleet can be replaced. Where breakers exhibit unacceptable performance that cannot be resolved with a reasonable level of maintenance, these breakers will be targeted for replacement.

Bushings from oil circuit breakers need to undergo oil retro-fill or replacement in order to satisfy federal PCB regulatory requirements[1] to remove equipment containing concentrations of PCB greater than 50 ppm from service by 2025. All transmission station oil-filled equipment manufactured prior to 1985 are expected to be sampled by the end of 2022, so that the PCB contained in such equipment can be removed or retro-filled to less than 50 ppm by the end of 2025.

PROTECTION EQUIPMENT DEMOGRAPHICS – CONNECTION STATIONS

In contrast to transformers and breakers (which are replaced based on condition of asset components), it is not possible to assess the physical condition of this class of asset and as such, the expected service life (ESL) of protection devices plays an important role in the replacements of protection relays. This is because assessment for physical breakdown or loss of strength over time is not feasible nor relevant given the make-up of these electronic or solid state devices. Hydro One also uses other factors as triggers for replacement decision, including: increased failure rates related to specific models or families of devices, limited or non-existent manufacturer support (i.e. in terms of the provision of spare parts and repair services), and the inability to comply with current reliability standards. As such, to prevent the potentially

[1] Canadian Environmental Protection Act, 1999 - PCB Regulations SOR/2008-273.

significant reliability and safety impact of a sudden failure, ESL is a key trigger for further evaluation to confirm replacement needs.

As explained in TSP Section 2.2, approximately 27% of the protection system population is operating beyond its ESL. Furthermore, over 90% of the solid-state fleet is already operating beyond ESL. Such devices are subject to an elevated risk of failure, while also having very limited or no support from vendors in terms of replacement units, spare parts, and engineering and firmware support. As such, reactive repairs may involve extended durations as re-engineering and construction work will be required to install new devices based on different technology. These risks could lead to prolonged outages for customers.

Without investments, critical assets at connection stations will continue to degrade and the number of assets in poor condition will continue to increase, thereby resulting in increased risk of unexpected failures.

C. INVESTMENT DESCRIPTION

As discussed above, this Investment focuses on the replacement of multiple connection station assets that facilitate power transformation from a high transmission voltage to a lower transmission voltage. This bundled approach focuses on a particular station where multiple key station assets require replacement, as driven by their condition, and may be accompanied by some level of electrical re-configuration to address operating concerns and customer preferences or to standardize the installed equipment. In the case where there are relatively few assets identified at a particular station for replacement (e.g. one of the key station asset and accompanying ancillary equipment or a small subset of the minor station assets), this station is identified as a candidate for a particular asset-focused replacement project, as further described in ISD-SR-09 and ISD-SR-10.

As described in SPF Section 1.7 and TSP Section 2.7, Hydro One performs an asset risk assessment and, if as a result of this assessment, Hydro One identifies multiple assets that are in poor condition, then this station is subsequently identified as a candidate investment. All candidate investments, identified for replacement, undergo the risk based prioritization assessment to determine whether they need to be included in the Investment Plan. As a result of the investment planning process, over the 2023-2027 period, the Investment targets 93 stations and addresses the replacement of 151 transformers (93 to be in-serviced during the 2023-2027 period), 609 breakers (365 to be in-serviced during the 2023-2027 period), and 1570 protection systems (922 to be in-serviced during the 2023-2027 period). While Hydro One has a significant number of transmission station assets that are in poor condition, the pacing of the Investment does not target all of them. The Investment primarily addresses critical and pressing issues that require attention. Hydro One will also address other minor station assets (e.g. ancillary equipment) where condition warrants replacement as well as any potential site and property issues, customer issues, safety and/or environmental concerns. A more detailed list of assets planned for replacement is presented in **Appendix "A"** below.

Hydro One also performs functional reconfiguration analyses to ensure alignment with load forecasts and applicable industry and regulatory standards. Functional reconfiguration is the reconnection of power system elements (e.g. breakers, transformers) within a transmission station into a new electrical configuration. This can either better facilitate a customer connection, a connection to the bulk power system or help eliminate operational restrictions or limitations which can aid in the transfer or restoration of power during a faulted condition where an element is removed from service. Functional configuration, where possible, allows Hydro One to replace two smaller rated transformers with a single standardized transformer that delivers the same capacity. This helps Hydro One maintain a standardized catalogue of power equipment to minimize the various types of spare equipment required. Hydro One will remove 5 transformers and 5 breakers from service to account for functional reconfiguration.

Hydro One actively works with its customers to capture their needs and preferences and implement the necessary changes to Hydro One designs, where feasible, to meet those needs. Hydro One carried out a comprehensive, two-phase customer engagement to inform the development of investment strategies and candidate investments, including the pacing of transmission station and lines reinvestment. Across all customer types, customers chose the draft plan (as further discussed in SPF Section 1.6 and 1.7, and TSP Section 2.7) as their preferred option for replacing transmission station assets in poor condition. In regard to replacing aging transmission stations, Hydro One's customers expressed strong support for the replacement of aging and deteriorating transmission station assets to maintain the overall health of the system. Hydro One's investment plan addresses aging and deteriorated assets and has been optimized to sustain the current performance of the transmission system, matching customers' expectations.

D. OUTCOMES

As a result of the Investment, Hydro One will reduce operational risks associated with the operation of equipment in poor condition; ensure compliance with the Ministry of Environment, Conservation and Parks (MOECP) in regard to oil spills; maintain long-term reliability of the connection stations; eliminate operational concerns through reconfiguration; and reduce constraints on generation resources.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the OEB's:

Table 2 - Outcomes Summary

Customer Focus	• Maintain reliable power delivery at connection stations.
Operational Effectiveness	• Improve the operational effectiveness of connection stations through reconfiguration and standardization of new equipment and design.
Public Policy Responsiveness	• Ensure compliance with applicable regulatory requirements.
Financial Performance	• Realize cost savings by addressing multiple deteriorated assets within a station as part of the same investment. • Efficiencies in design, construction, commissioning and outages by addressing multiple assets within a station in one investment.

E. EXPENDITURE PLAN

As discussed above, the Investment is needed to replace various connection station assets that are in poor condition, which may lead to unexpected failures. Hydro One planned the Investment to achieve completion as effectively and efficiently as possible.

Table 3 below projected spending on the aggregate investment level.

Table 3 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Capital and Minor Fixed Assets	381.6	347.4	368.9	363.1	423.8	441.9	313.2	2,640.0
Less Removals	11.7	10.4	11.2	13.0	17.4	13.4	13.8	90.9
Gross Investment Cost	**369.8**	**337.1**	**357.7**	**350.1**	**406.5**	**428.6**	**299.4**	**2,549.1**
Less Capital Contributions	12.0	2.6	0.0	0.0	0.0	0.0	0.0	14.6
Net Investment Cost	**357.9**	**334.5**	**357.7**	**350.1**	**406.5**	**428.6**	**299.4**	**2,534.6**

The factors influencing the cost of the investment include:

- The number of transformers, breakers, protection systems, and ancillary equipment being replaced
  - Higher voltage transformers and breakers and ancillary equipment are more costly from a material perspective as is the overall installed cost due to required clearances for high voltage equipment.
- Applicability of MOECP, requirements
  - Where stations are subject to environmental work (i.e. spill containment and/or oil water separators are required) increased costs may be incurred to facilitate the work required to meet the requirements.
- The complexity of project staging and outages required to facilitate work
  - The more complex the project, the more inter-connections, and the more outages required will increase the cost of the project.

- Whether the Project is a Greenfield replacement or in-situ replacement requiring complex contingency planning
    - Generally, if space permits, either within the existing station fence or nearby, a Greenfield solution may be less costly as it can be constructed with minimal interference to daily operations.
    - In situ replacement is generally more difficult, from both engineering design and construction perspectives as other equipment will need to be removed from service to facilitate construction and ensure safety and appropriate clearances. This increases the time required for construction and can impact customers as they will be supplied from only a single supply during these times.
- The location of the station, whether in an isolated rural area or congested urban area
    - Generally working in a congested urban station will increase costs and lengthen the overall construction time of the project with respect to clearances in order to work safely.

F. ALTERNATIVES CONSIDERED

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

ALTERNATIVE 1: REACTIVE COMPONENT REPLACEMENT

Reactive component replacement involves waiting for deteriorated condition transformers, breakers, or ancillary equipment to fail and replace components on a reactive basis. Hydro One does not run transmission assets to failure given their criticality to the integrity of the transmission system and the significant reliability, safety and environmental impact associated with their failures. This alternative is more costly not only for Hydro One but also for impacted customers. Hydro One has rejected this alternative for the following reasons:

- Assets in deteriorated condition will continue to deteriorate and decline, thereby increasing the likelihood of unexpected failures. When a critical asset fails, redundancy is lost for several months. In the case where a subsequent failure of a companion unit occurs, the consequences could be significant to the transmission system. Such a failure would be prolonged and result in extended equipment and customer outages which will subsequently negatively affect the Transmission System Average Interruption Duration Index (SAIDI) and Transmission System Average Interruption Frequency Index (SAIFI) performance.

- At the majority of connection stations, a significant proportion of station load may be 'stranded', meaning the load cannot be immediately transferred to another station or transferred within the distribution system. A failure at a vulnerable station with stranded load would result in extended power outages until an emergency measure is implemented.
- An increased likelihood of unexpected failures would lead to increased environmental risk due to the possibility of a release into the environment during a failure event.
- An increased likelihood of unexpected failures would lead to increased safety risk due to the possibility of a failure event being catastrophic in nature.
- Since these replacements would likely be executed on an emergency basis, it would result in constant reprioritization of planned work and inefficient redeployment of resources.
- This alternative limits the ability to account for future requirements and has a high risk of re-work and future additional costs.
- This strategy is likely to increase operating and maintenance costs, decrease equipment performance and may impact the safety of personnel on site.

ALTERNATIVE 2: PLANNED PROGRAMMATIC REPLACEMENT OF COMPONENTS (UNBUNDLED)

Planned Replacement of Components (Unbundled) alternative involves replacing individual station components in poor condition. This alternative is viable only when a single key component at a transmission station has deteriorated, as described in T-SR-09 and/or T-SR-10. Unlike reactive replacements, planned replacements have the advantage of minimizing system and equipment outages through coordinated outage plans. However, this alternative is not efficient when multiple components at a transmission station are in deteriorated condition or operational concerns exist with respect to these components. In this case, Hydro One would not realize any efficiency during execution of the design, construction, and commissioning stages of the work that a station-centric, bundled replacement strategy offers. Furthermore, this alternative does not offer any opportunities to reconfigure the physical or electrical layout of the station in order to minimize future maintenance requirements or to eliminate any existing operational concerns.

ALTERNATIVE 3: BUNDLED INTEGRATED REPLACEMENT OF COMPONENTS

Bundled Replacement of Components is the preferred investment option at connection stations. This integrated approach addresses the needs identified at the transmission station to maintain reliability for Hydro One's transmission system in the most cost effective and efficient manner. Hydro One can refurbish entire stations that have a significant population of assets in poor condition, before failures occur. Furthermore, for transmission stations that have a significant population of deteriorated, poor condition assets and where operational concerns could be mitigated or eliminated through reconfiguration, station refurbishment is the best alternative as it enables a holistic assessment of asset and operational needs which are consolidated into a single integrated investment. Bundling the replacement of transmission station components also reduces the number and duration of planned outages affecting customers connected to the station. For example, if a circuit breaker disconnect switch is replaced together with the circuit breaker outages, efficiencies are realized since the grouped equipment that requires an outage is similar for the switch as it is for the breaker. Had the replacements been sequential the outages for the replacements would have to be duplicated, as would the resource requirements to complete the work.

G. EXECUTION RISK AND MITIGATION

As described in TSP Section 2.10, Hydro One follows a Transmission Capital Project Delivery Model, throughout which project risks are identified and mitigation plans are implemented. Risks that can impact the completion of transmission station renewal projects at connection stations include:

- Outage constraints

- Planned outages are required to replace assets. Outages may include individual assets, sections of a station, or the entire station for construction and commissioning staff to perform replacement of assets.
- Outages must be planned and coordinated to minimize the impact to customers.

- Resource constraints
  - All transmission station renewal projects use the same teams of management and engineering resources.
  - Projects in the same geographical location use the same teams of construction and commissioning resources.
- Construction execution challenges
  - Existing station equipment may require retrofits to accommodate new assets as station design and equipment standards have evolved.
  - Significant design and construction is required to replace assets if assets cannot be replaced in the same physical location due to space constraints, outages or safety consideration.
- Customer coordination
  - Hydro One makes best effort to coordinate with customers
  - At connection facilities serving commercial and industrial customers, Hydro One coordinates with planned customer outages or shut downs.
- Real estate requirements
  - Station expansion and new land may be required when assets cannot be replaced in the same physical location.
- Procurement challenges
  - Major equipment procurement lead times can be long.
  - Hydro One engaged vendors at appropriate times in the planning process to ensure sufficient lead times to obtain major equipment.

APPENDIX A – DESCRIPTION OF INVESTMENTS

ISD Ref.	Station Name/Circuit	Scope, Need and Outcome	Forecast Replacement Units		
			Trfr	Brkr	Prot
T-SR-03.01	Parry Sound TS	• This investment involves the replacement of 230kV/44 kV transformers, 44kV switches, AC and DC station service equipment, instrument transformers, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. • This investment is expected to maintain reliability to the local customers and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	18
T-SR-03.02	Port Colborne TS	• This investment is a complete station refurbishment that will replace all assets including transformers, medium voltage switching facilities and station protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete at Port Colborne TS. The transformers are exhibiting oil leaks and have had performance issues including a catastrophic failed low voltage bushing that caused damage to nearby equipment and compromised supply reliability. • This investment is expected to maintain long-term supply reliability to Canadian Niagara Power Inc. customers and reduce the risk of unplanned outages due to asset failure.	2	8	16
T-SR-03.03	Main TS	• This investment involves the replacement of the power transformers, other ancillary assets, plus the renewal and upgrade of general station infrastructure including fire walls, spill containment & drainage systems, and noise abatement walls. • This investment is needed to address the power transformers and station infrastructure in poor condition. • This investment is also needed to address the capacity increase requested by Toronto Hydro. • This investment is expected to maintain long-term supply reliability to Toronto Hydro customers, and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	0
T-SR-03.04	Wilson TS	• This investment involves the replacement of 230-44 kV transformers, 44kV switchyard, and protection and control equipment • This investment is needed to address the poor condition of the transformers as recent condition assessments show that these units have rapidly degraded as indicated by gassing and cooling system issues as well as poor condition and/or obsolete oil filled circuit breakers and the existing legacy LV switchyard. • The investment is expected to decrease risk of equipment failure, maintain supply reliability to Oshawa PUC and Hydro One Distribution customers and address complaints from neighboring residential community regarding noise emanating from poor condition transformers.	2	13	40

T-SR-03.05	Wonderland TS	• This investment involves the replacement of LV switchyard components including breakers, switches, station services, capacitors and protection & control. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain existing system reliability and is not meant for system capacity increase purposes. The benefits of this investment are mitigation of risk associated with poor condition equipment and removal of legacy obsolete equipment.	0	13	24
T-SR-03.06	Moose Lake TS	• This investment involved the replacement of 115kV transformer, 44kV breaker, instrument transformers, station service transformers, DC station service and transfer scheme and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain system reliability; and is not expected to increase capacity. The benefits of this investment is mitigation of poor equipment health and in turn risk of failure on the system.	2	2	20
T-SR-03.07	Orangeville TS	• This investment involves the replacement of transformers, 44kV transformer breakers, and protection and control equipment. This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to decrease risk of equipment failure, maintain supply reliability to Orangeville Hydro and Hydro One Distribution customers in the Orangeville area.	4	4	12
T-SR-03.08	Lambton TS	• This investment involves the replacement of autotransformers, a step-down transformer and LV switchyard components including breakers, switches, protection and control equipment, and the installation of additional station services. • This investment is needed to address equipment that is in poor condition or is obsolete. • The consolidation of two (2) 600 MVA autotransformers into a single larger 1000MVA unit is required as approved by the IESO and identified in the joint Michigan-Ontario interface study with MISO. • The installation of additional station services supplies is needed to comply with OPSRP. The investment is expected to maintain existing system reliability and is not meant for system capacity increase purposes. The benefits of this investment are mitigation of risk associated with poor condition equipment and removal of legacy obsolete equipment.	4	9	22
T-SR-03.09	Crowland TS	• This investment involves the replacement of transformers, the associated protection equipment and reconfiguration and replacement of various 115 kV switches. • This investment is needed to address equipment that is in poor condition or is obsolete. The replacement of the 115 kV switches in the high voltage switchyard is required to meet current regional power flow requirements. This investment is expected to maintain long-term supply reliability to Welland Hydro customers and reduce the risk of unplanned outages due to asset failure	2	0	4

T-SR-03.10	Slater TS	• This investment involves the replacement of transformers, the AC station service system and reconfigure the station DC supply and upgrade associated protection and control equipment at Slater TS. • This investment is needed to address equipment that is in poor condition. This investment is expected to maintain supply reliability to Hydro Ottawa customers and decrease the risk of equipment failure.	2	0	0
T-SR-03.11	Lincoln Heights TS	• This investment involves the replacement of transformers and the protection and control equipment at station. • The investment is needed to address assets in poor condition based on the asset condition assessment. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to Hydro Ottawa customers.	2	0	25
T-SR-03.12	Arnprior TS	• This investment involves the replacement of transformers and associated assets, building a new PCT building, replacement of the MV switchyard and reconfiguration of the AC station service. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain supply reliability to Hydro Ottawa customers and decrease the risk of equipment failure.	2	5	17
T-SR-03.13	John TS	• This investment involves the replacement of step-down transformers and associated protective relays, disconnect switches, and neutral reactors. • This investment also involves civil reinforcement for oil spill management. • This investment is needed to address the poor condition of the transformers such as oil leaking, and operational deficiency of tap changers. • The need for the investment is published in Metro Toronto Regional Infrastructure Plan in March 2020. John TS is a critical station to serve loads in downtown Toronto. The investment is expected to mitigate environmental risks of transformer failure in a heavily populated region and maintain load supply reliability to Toronto Hydro.	2	0	0
T-SR-03.14	Rexdale TS	• This investment involves the replacement of existing 27.6kV metalclad switchgear assets with indoor Medium Voltage Gas-Insulated Switchgear (MVGIS) and protection and control systems. • This investment is needed to address the deteriorated condition and obsolescence of the existing 27.6kV metalclad switchgear assets and protections. The existing breaker type is obsolete, not suited for capacitive switching and failures have been experienced in the past. This investment is expected to maintain long-term supply reliability to Toronto Hydro-Electric System Limited customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	22	36
T-SR-03.15	Kirkland Lake TS	• This investment involves the replacement of 44 kV breakers, 115 kV line disconnect switch, instrument transformers, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete.	0	8	19

Witness: REINMULLER Robert

		• This investment addresses the DC battery system to meet standard requirements and risk related to basement flooding. • This investment replaces the obsolete low voltage structure design that does not conform to current safe operation standards that prevents timely maintenance, and to avoid numerous and prolonged outages to Distributed Generator customers. • This investment is expected to maintain reliability to local customers and improve reliability to the broader 115 kV system by the removal of the auto-grounds and implementation of telecommunications. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure.			
T-SR-03.16	Fairbank TS	• This investment involves the replacement of 110-28 kV 50/83MVA power transformers and both switchyards at Fairbank TS. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain reliability to local customers, and mitigate the risk of outages and supply interruptions due to asset failure.	4	23	41
T-SR-03.17	Bridgman TS	• This investment involves the replacement of power transformers, other ancillary assets, plus the renewal and upgrade of general station infrastructure including support structures, fire walls, spill containment & drainage systems, and noise abatement walls in a complex and space-constrained mid-town Toronto location. • This investment is needed to address the power transformers and station infrastructure in poor condition. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers, and mitigate the risk of outages and supply interruptions due to asset failure.	4	0	0
T-SR-03.18	Murray TS	• This investment involves the replacement of power transformers and metalclad switchgear at Murray TS. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain reliability to local area customers and mitigate the risk of outages and supply interruptions due to asset failure.	2	9	19
T-SR-03.19	Lauzon TS	• This investment involves the replacement of 230-27.6kV transformers and the 27.6kV switchyard • This investment is needed to address the poor condition of the transformers as recent condition assessments show that these units have rapidly degraded as indicated by gassing • To accommodate an expected increase in station capacity requirements, the existing 27.6kV low voltage Jones switchyard will be replaced and reconfigured with a Bermondsey switchyard. The investment is expected to decrease risk of equipment failure, maintain supply reliability to EnWin Utilities Ltd. and Hydro One Distribution customers, and ensure the necessary capacity is available to meet the long term customer demand forecast.	3	10	0

Witness: REINMULLER Robert

T-SR-03.20	Longueuil TS	• This investment involves the replacement of 230/44kV, 56/75/93 MVA step-down transformers, transformer spill containment, AC station service, and associated protection and controls equipment at the 55 year old DESN station. • This investment is needed to address equipment that is in poor condition. The investment is expected to maintain overall station reliability, eliminate operation risks associated with operating poor condition equipment, and ensure continued supply reliability to Hydro One Distribution customers in the area.	2	0	0
T-SR-03.21	Bridgman TS & High Level MS	• This investment involves the replacement of supply breakers associated ancillary components that will supply Toronto Hydro's replacement A1-A2 switchgear at High Level MS in midtown Toronto. The investment also involves some minor work at Bridgman TS including neutral grounding reactor replacements and current limiting reactor removals. This investment is needed to address equipment that is in poor condition. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	3	0
T-SR-03.22	Riverdale TS	• This investment involves the replacement of 115kV oil circuit breakers and electromechanical and solid-state protection relays. • This investment is needed to address the poor condition of the circuit breakers and the obsolete protection and control equipment. The investment is expected to maintain supply reliability to Hydro Ottawa customers.	0	2	20
T-SR-03.23	Port Arthur TS	• This investment involves the replacement of 27.6kV circuit breakers, low voltage switches, AC and DC station service equipment, instrument transformers, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain reliability to the local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	9	28
T-SR-03.24	Port Hope TS	• This investment involves the replacement of transformers and other assets. • This investment is needed to address the poor condition of the transformers, which have shown degraded condition, including leaking oil and tap-changer issues. The investment is expected to prevent equipment failure, and maintain reliability to Hydro One Distribution customers.	2	9	0
T-SR-03.25	Manby TS	• This investment involves the replacement of 230/28kV transformers at Manby TS. • This investment is needed to address equipment that is in poor condition or is obsolete. • The transformers are non-standard 56/93MVA units and will be replaced with standard 50/83MVA capacity units. The investment is expected to maintain reliability to local customers, and mitigate the risk of outages	2	0	2

		and supply interruptions due to asset failure.			
T-SR-03.26	Elliot Lake TS	• This investment involves the replacement of an 115kV/44 kV Transformer, 44 kV breakers; AC station service transfer scheme, DC Battery Charger, AC station service transformers, disconnect switches and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain reliability to the local customers; and is not expected to increase capacity. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure.	2	3	10
T-SR-03.27	Preston TS	• This investment involves transformers, and associated disconnect switches, surge arresters, neutral grounding reactors, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. • The Kitchener Waterloo Cambridge Guelph Region's Needs Assessment published in December 2018 records the need of this investment. Preston TS is one of the critical stations that serves the Cambridge area and Toyota plant in Cambridge. The investment will mitigate risks of transformer failure and provide operational flexibility to LDCs and help in catering the anticipated future load growth.	2	0	21
T-SR-03.28	Wallace TS	• This investment involves the replacement of transformers, oil circuit breakers, and protection and control equipment. • This investment is needed to address the poor condition of the transformers, oil circuit breakers, and obsolete protection and control equipment. The investment is expected to maintain reliability of supply to Hydro One Distribution customers in eastern Ontario, and decrease the risk of equipment failure.	2	3	7
T-SR-03.29	Bermondsey TS	• This investment involved the replacement of power transformers. • Both units are in poor condition. T3 is a 230/28-28kV 84/140MVA non-standard unit and T4 is a 230/28-28kV 75/125MVA unit. Both transformers will be replaced with standard 75/125MVA capacity units. The investment is expected to maintain reliability to local customers, and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	0
T-SR-03.30	Scarboro TS	• This investment involves the replacement of the power transformer, other ancillary assets, plus the renewal and upgrade of general station infrastructure including fire walls, spill containment and drainage systems, and noise abatement walls. • This investment is needed to address the power transformer and the general station infrastructure in poor condition. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers, and mitigate the risk of outages and supply interruptions due to asset failure.	1	0	0

T-SR-03.31	Newton TS	• This investment involves the replacement of 115 kV oil circuit breakers, the associated breaker disconnect switches, 115 kV line switches and associated breaker protection devices • This investment is needed to address poor condition oil breakers. In addition, the PCB content of the breakers exceeds acceptable levels as outlined by Environment Canada and therefore requires attention. This investment is expected to maintain the supply reliability of 115 kV switching facilities at Newton TS that facilitates regional power flows as well as meeting Environment Canada requirements	0	5	0
T-SR-03.32	St. Andrews TS	• This investment involves the replacement of step-down transformers, LV switchyard components including breakers, switches, station services, capacitors and protection and control. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain existing system reliability and is not meant for system capacity increase purposes. The benefits of this investment are mitigation of risk associated with poor condition equipment and removal of legacy obsolete equipment.	2	13	28
T-SR-03.33	Picton TS	• This investment involves the replacement of transformers. • This investment is needed to address the poor condition of the transformers. The investment is expected to maintain supply reliability.	2	0	0
T-SR-03.34	Midhurst TS	• This investment involves the replacement of a 230/44kV stepdown transformer, a 44kV breaker, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain existing system reliability and load serving capability of the system and is not meant for system capacity increase purposes. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure and removal of legacy obsolete equipment.	1	0	5
T-SR-03.35	Orillia TS	• This investment involves the replacement of a 230kV/44 kV transformer. • This investment is needed to address the transformer in poor condition. This investment is expected to maintain reliability to the local customers; and is not expected to increase capacity. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure.	1	0	0
T-SR-03.36	Bracebridge TS	• This investment involves the replacement of T1 power transformer at Bracebridge TS. • This investment is needed to address the transformer in poor condition. This investment is expected to maintain reliability to the local area customers and mitigate the risk of outages and supply interruptions due to asset failure.	1	0	0
T-SR-03.37	Charles TS	• This investment involves the replacement of non-standard 115/14 kV transformers to the standard size transformers, protection and control equipment, instrument transformers, and the renewal and upgrade of general station infrastructure including spill containment and drainage systems.	2	4	30

		• This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers, and mitigate the risk of outages and supply interruptions due to asset failure.			
T-SR-03.38	Manby TS	• This investment involves the replacement of the low voltage switchyard and components including 28kV breakers, switches, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure	0	12	6
T-SR-03.39	Russell TS	• This investment involves the replacement of 115/13.8/13.8kV, 45/60/75 MVA dual secondary transformers, 13.8kV metalclad switchgear, and associated protection and control equipment at the 50 year old station. • This investment is needed to address equipment that is in poor condition or is obsolete. • This investment will also address the recommendation from the recent Greater Ottawa Regional Infrastructure Plan (RIP) report to replace T1/T2 with new 45/60/75 MVA or 60/80/100 MVA units based on anticipated load at the station and giving consideration to right-sizing the transformers. The investment is expected to maintain overall station reliability, eliminate operational risks associated with operating poor condition equipment, and ensure continued supply reliability to Hydro Ottawa customers in the area.	2	6	21
T-SR-03.40	Duplex TS	• This investment involves the replacement of step-down transformers, infrastructure including spill containments, and protection and control equipment. • This investment is needed to address the poor condition of the T1 & T2 transformers. This investment is also needed to eliminate PCB contaminated equipment in the station in order to comply with environmental regulations. In addition, Toronto Hydro-Electric System Limited may request these transformers to be replaced with larger standard units in order to meet future supply demand. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers, and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	6
T-SR-03.41	Lake TS	• This investment involves the replacement of transformers, the associated high voltage disconnect switches and protection equipment. • This investment is needed to address equipment that is in poor condition or is obsolete and declining with known manufacturer issues. This investment is expected to maintain long-term supply reliability to Alectra Utilities customers and reduce the risk of unplanned outages due to asset failure	4	0	4
T-SR-03.42	Bunting TS	• This investment involves the replacement of transformer, station medium voltage switching facilities, and protection and control equipment.	1	17	33

		• This investment is needed to address the non-standard safety compromised medium voltage metalclad switching facilities along with a transformer that is in poor condition, leaking oil that also has tap changer and cooling issues. This investment is expected to maintain long-term supply reliability to Alectra Utilities customers and reduce the risk of unplanned outages due to asset failure. In addition, the deployment of a new protection and control protocol will enhance Hydro One's ability to provide robust and diverse protection and control schemes for future investments			
T-SR-03.43	Nebo TS	• This investment is involves the replacement of transformers, associated switches, spill containment facilities, and protection equipment. This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain long-term supply reliability to Alectra Utilities customers and reduce the risk of unplanned outages due to asset failure.	2	0	4
T-SR-03.44	Palermo TS	• This investment involves the replacement of transformers, associated switches, spill containment facilities, and protection equipment. • This investment is needed to address the poor condition power transformers that also have significant oil leaking issues. This investment is expected to maintain long-term supply reliability to Oakville Hydro customers and reduce the risk of unplanned outages due to asset failure.	2	0	0
T-SR-03.45	Carlton TS	• This investment involves the replacement of medium voltage switching facilities and protection and control systems. • The existing legacy medium voltage switching facilities comprised of an air insulated switchyard and metalclad switching facilities will be replaced with current standard Hydro One metalclad switchgear. • This investment is needed to address the poor condition and safety compromised medium voltage switching assets and structures at Carlton TS along with reconfiguring the station from a four transformer station to a two transformer station based on customer load forecasts. This investment is expected to maintain long-term supply reliability to Alectra Utilities customers and reduce the risk of unplanned outages due to asset failure	0	24	59
T-SR-03.46	Birmingham TS	• This investment involves the replacement of a 115/ 13.8 kV transformer, low voltage switchgear and two station service transformers. • This investment is needed to address replacement of equipment in poor condition. This station supplies an industrial customer with very large motors and is highly sensitive to any supply reliability issues. • This investment also addresses a problematic 115 kV line entrance to be reconfigured for the maintenance purposes. The investment is expected to maintain supply reliability to the local customers supplied by this station, and mitigate the risk of outages and supply interruptions due to asset failure.	1	21	0

Witness: REINMULLER Robert

T-SR-03.47	Carling TS	• This investment involves the replacement of all electromechanical and solid state protection and control equipment. • This investment is needed to address these assets which are now obsolete. This investment is expected to improve the security of protection operations for Hydro Ottawa customers.	0	0	35
T-SR-03.48	Cherrywood TS	• This investment involves the replacement of 44 kV oil-filled circuit breakers and associated disconnect switches and protection and control equipment. • As a result of the final plan for Fairpoint DS (Elexicon Energy Inc. distribution station located within Cherrywood TS), additional reconfiguration in the 44 kV switchyard may be required. • This investment is needed to address equipment that is in poor condition or is obsolete. • The "right sizing" option was considered and evaluated in the GTA East Regional Infrastructure Planning report published in February 2020 for these assets and it was recommended to replace them like-for-like with current standard equipment. This investment is expected to mitigate the risk of equipment failure and maintain supply reliability to Elexicon Energy Inc and Hydro One Distribution customers in the Pickering area.	0	10	22
T-SR-03.49	Gage TS	• This investment involves the refurbishment of the T8/T9 DESN at Gage TS. This includes replacement of both transformers and switchgear. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain supply reliability to the local customers supplied by this station, and mitigate the risk of outages and supply interruptions due to asset failure.	2	15	22
T-SR-03.50	Woodbridge TS	• This investment involves the replacement of a step-down transformer, station infrastructure including spill containment. • This investment is needed to address the poor condition T5 transformer. This investment is expected to maintain long-term supply reliability to Alectra and Hydro One Distribution customers in the north GTA, and mitigate the risk of outages and supply interruptions due to asset failure.	1	0	0
T-SR-03.51	Fairchild TS	• This investment involves the replacement of the power transformers, protection and control systems, plus the renewal and upgrade of general station infrastructure including fire walls, spill containment and drainage systems, and noise abatement walls. • This investment is needed to address the power transformers and station infrastructure in poor condition, and the obsolete protection and control systems. This investment is expected to maintain long-term supply reliability to Toronto Hydro and Alectra Utilities customers, and mitigate the risk of outages and supply interruptions due to asset failure.	3	0	34

Witness: REINMULLER Robert

T-SR-03.52	Cedar TS	• This investment involves the replacement of 115-13.8kV transformers, 115kV switches, associated switchgear, and protection and control equipment. • This investment is needed to address the poor condition of the transformers as indicated by recent condition assessments, oil leaks and cooling system issues; poor condition and obsolescence of protection equipment. The investment is expected to decrease risk of equipment failure and maintain supply reliability to Alectra Utilities customers.	2	0	4
T-SR-03.53	Halton TS	• This investment involves the replacement of protection and control systems and other ancillary assets. • This investment is needed to address PALC relays that are obsolete and have a high rate of failure. This investment is expected to maintain long-term supply reliability to Milton Hydro and Halton Hills Hydro customers, mitigate the risk of outages and supply interruptions due to asset failure and obsolescence.	0	0	29
T-SR-03.54	Waubaushene TS	• This investment involves the replacement of 230/44kV stepdown transformers and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain existing system reliability and load serving capability of the system. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure and removal of legacy obsolete equipment.	2	0	5
T-SR-03.55	Kent TS	• This investment involves replacement of 230-27.6kV transformer, 27.6 kV oil-filled circuit breakers, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to decrease risk of equipment failure and maintain long-term reliability of supply to Entegrus Powerlines Inc. and Hydro One Distribution and eliminate existing maintainability challenges with legacy 27.6kV switchyard that could impact future reliability and performance	1	11	19
T-SR-03.56	Muskoka TS	• This investment involves the replacement of 44kV circuit breakers, low voltage switches, station service transformers, and instrument transformers. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain reliability to the local customers and to mitigate the risk of outages and supply interruptions due to asset failure.	0	7	0
T-SR-03.57	Timmins TS	• This investment involves the replacement of a 115kV stepdown transformer and the associated electro-mechanical protection. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain reliability to the local customers. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure.	1	0	1

T-SR-03.58	Glendale TS	• This investment involves the replacement of transformers, medium voltage switching facilities, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. • The switching facilities are considered legacy and non-standard. In addition, all site protection and control facilities will be replaced with current Hydro One standard equipment. This investment is expected to maintain long-term supply reliability to Alectra Utilities customers and reduce the risk of unplanned outages due to asset failure.	4	21	64
T-SR-03.59	Vansickle TS	• This investment involves the replacement of metalclad switchgear and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	9	13
T-SR-03.60	Dundas TS	• This investment involves the replacement of 27.6 kV low voltage switchgear. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain supply reliability to the local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	13	8
T-SR-03.61	Mohawk TS	• This investment involves the replacement of 13.8 kV low voltage switchgear and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain supply reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	6	17
T-SR-03.62	Bathurst TS	• This investment involves the replacement of a step-down transformer, circuit breakers, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain long-term supply reliability to Toronto Hydro-Electric System Limited customers, and mitigate the risk of outages and supply interruptions due to asset failure.	1	7	11
T-SR-03.63	Leslie TS	• This investment involves the replacement of a 230/27.6/13.8kV 75/125MVA power transformer, 27.6kV and 13.8kV breakers and switches, protection and control system upgrade and other auxiliary assets. • This investment is needed to address the poor condition and performance of the assets and the obsolete protection and control equipment. This investment is expected to maintain supply reliability to local customers (Toronto Hydro and Alectra), and mitigate the risk of outages and supply interruptions due to asset failure.	1	8	43
T-SR-03.64	Burlington TS	• This investment involves the replacement of 27.6 kV low voltage switchgear and protection and control equipment.	0	9	32

		• This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain supply reliability to local customers supplied by this station, and mitigate the risk of outages and supply interruptions due to asset failure.			
T-SR-03.65	Alliston TS	• This project involves the replacement of 230/44kV step-down transformers • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain existing system reliability. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure and removal of legacy obsolete equipment.	2	2	0
T-SR-03.66	Dobbin TS	• This investment involves the replacement of transformers, 230kV, 115kV, and 44kV oil breakers, AC & DC equipment, and associated protection and control equipment at the station. • This investment is needed to address assets in poor condition based on the asset condition assessment. This investment is expected to reduce risk of equipment failure, and maintain reliability of the BES and to Hydro One customers.	4	19	48
T-SR-03.67	Strachan TS	• This investment involves the replacement of 110/14-14kV 45/75MVA transformers and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain reliability to local customers, and mitigate the risk of outages and supply interruptions due to asset failure.	3	0	8
T-SR-03.68 A&B	Clarke TS	• This investment involves the replacement of step-down transformers, associated disconnect switches, LV switchyard components including breakers, station services, capacitors and protections. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain existing system reliability. The benefits of this investment are mitigation of risk associated with poor condition equipment and removal of legacy obsolete equipment.	2	9	20
T-SR-03.69	Albion TS	• This investment involves the replacement of transformers, 13.8kV breakers, and associated protection and control equipment at the station. • This investment is needed to address these assets in poor condition or is obsolete. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to Hydro Ottawa customers.	2	12	25
T-SR-03.70	Bilberry Creek TS	• This investment involves the replacement of transformers, oil circuit breakers, and associated protection and control equipment at the station. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to Hydro One Distribution and Hydro Ottawa customers.	2	5	17

T-SR-03.71	Talbot TS	• This investment involves the replacement of step-down transformers, disconnect switches, LV switchyard components including breakers, station services, capacitors, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain existing system reliability. The benefits of this investment are mitigation of risk associated with equipment in poor condition and removal of obsolete equipment.	2	9	0
T-SR-03.72	Havelock TS	• This investment involves the replacement of 230/44kV, 50/83 MVA transformers, 44kV breakers, and protection and control equipment at the 55 year old station Havelock TS. • This investment is needed to address assets in poor condition or that are obsolete. • This investment also addresses the recommendation from the recent Peterborough to Kingston Needs Assessment report to replace the T1 and T2 transformers with new, similar size 50/83 MVA units, giving consideration to right-sizing the transformers. The investment is expected to maintain overall station reliability, eliminate operational risks associated with operating poor condition equipment, and ensure continued supply reliability to Hydro One Distribution customers in the area.	2	3	7
T-SR-03.73	Lisgar TS	• This investment involves the replacement of a transformer and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to Hydro Ottawa customers.	1	0	22
T-SR-03.74	Duplex TS	• This investment involves the replacement of step-down transformers, infrastructure including spill containments, and protection and control equipment. • This investment is needed to address the poor condition of the T3 and T4 transformers. This investment is also needed to eliminate PCB contaminated equipment in the station in order to comply with environmental regulations. • In addition, Toronto Hydro-Electric System Limited may request these transformers to be replaced with larger standard units in order to meet future supply demand. This investment is expected to maintain long-term supply reliability to Toronto Hydro-Electric System Limited customers, and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	6
T-SR-03.75	Crystal Falls	• This investment involves the replacement of 230/44kV step-down transformers, 44kV breakers, switches, station service transformers, instrument transformers, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain existing system reliability and is not expected to increase existing system capacity. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure and removal of legacy obsolete equipment.	2	3	13

T-SR-03.76	Douglas Point TS	• This investment involves the replacement of 230/44kV step-down transformers including Oil Water Separators, 44kV Breakers, 230kV Air Break Switches, 44kV Switches, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain existing system reliability. The benefits of this investment are mitigation of risk associated with poor condition equipment and removal of legacy obsolete equipment.	2	10	25
T-SR-03.77	Trout Lake TS	• This investment involves the replacement of 230/44 kV 75/125 MVA power transformers and 44 kV breakers. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain reliability to local customers. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure.	2	5	0
T-SR-03.78	Lauzon TS	• This investment involves the replacement of 230-27.6kV transformers, 27.6kV breakers, 115kV breakers, associated switchgear and protection and control equipment. This investment is needed to address the poor condition of the transformers as indicated by recent condition assessments, oil leaks and cooling system issues; the degraded condition of select high voltage and low voltage breakers. The investment is expected to decrease the risk of equipment failure and maintain supply reliability to Hydro One Distribution customers in the city of Windsor.	1	3	37
T-SR-03.79	Galt TS	• This investment involves the replacement of the oil circuit breakers and associated protection and control equipment at the station. • This investment is needed to address equipment that is in poor condition or is obsolete. • Kitchener Waterloo Cambridge Guelph Region's Integrated Regional Resource Plan (IRRP) notes the need of this investment. Galt TS is one of the critical stations to serve Cambridge area. The investment will mitigate risks of breaker failure.	0	14	24
T-SR-03.80	Martindale TS	• This investment involves the replacement of two transformers. • The investment is needed to address transformers in poor condition. The investment is expected to maintain existing system reliability and is not meant for system capacity increase purposes. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure and removal of legacy obsolete equipment.	2	6	0
T-SR-03.81	Bruce HWB TS	• This investment involves the replacement of step-down transformers, oil water separators, 13.8kV breakers, 230kV switches, and protection equipment. • The investment is needed to address assets in poor condition or that are obsolete. The investment is expected to maintain existing system reliability. The benefits of this investment are mitigation of risk associated with poor condition equipment and removal of legacy obsolete equipment.	2	3	19

Witness: REINMULLER Robert

T-SR-03.82	Campbell TS	• This investment involves the replacement of breakers and protection and control systems, plus the renewal and upgrade of general station infrastructure including HVAC and Fire Alarm systems. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain long-term supply reliability to London Hydro customers, mitigate the risk of outages and supply interruptions due to asset failure.	0	3	32
T-SR-03.83	Bramalea TS	• This investment involves the replacement 230/44kV 50/83MVA transformers. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain reliability to local customers, and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	6
T-SR-03.84	Erindale TS	• This investment involves the replacement of the protections, one 44kV Breaker, and AC station service at Erindale TS. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	1	56
T-SR-03.85	Gardiner TS	• This investment involves the replacement of 230/44kV, 75/100/125 MVA step-down transformers, transformer spill containment, AC station service, and associated protection and control equipment. • This investment is needed to address assets in poor condition or that are obsolete. The investment is expected to mitigate risk of equipment failure and maintain supply reliability to Hydro One distribution customers in the region.	2	3	24
T-SR-03.86	Morrisburg TS	• This investment involves the replacement of AC station service, DC station service, and protection and control equipment at the 60 year old station. • This investment is needed to address these assets in poor condition and require replacement. The investment is expected to mitigate risk of equipment failure and maintain supply reliability to Hydro One distribution customers in the area.	0	0	31
T-SR-03.87	Nepean TS	• This investment involves the replacement of 230/44kV, 75/100/125 MVA transformers, DC station service, and oil-water separator. • Transformers T1/T2 will be replaced with new, similar size 75/100/125 MVA units, giving consideration to right-sizing the transformers. • This investment is needed to address equipment that is in poor condition. The investment is expected to maintain overall station reliability, eliminate operational risks associated with operating poor condition equipment, and ensure continued supply reliability to Hydro Ottawa customers in the area.	2	0	0
T-SR-03.88	Beach TS	• This investment involves the replacement of transformers, and the medium voltage legacy metalclad switchgear.	2	22	0

Witness: REINMULLER Robert

		• This investment is needed to address equipment that is in poor condition or is obsolete. In addition, the existing metalclad switchgear presents health and safety challenges during routine maintenance. This investment is expected to maintain long-term supply reliability to Alectra Utilities customers and reduce the risk of unplanned outages due to asset failure.			
T-SR-03.89	Port Arthur TS	• This investment involves the replacement of 115kV circuit breakers, high voltage switches, AC and DC station service equipment, instrument transformers, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain reliability to the local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	8	9
T-SR-03.90	South March TS	• This investment involves the replacement of 230/44kV, 50/67/83 MVA step-down transformers and protection and control equipment. • This investment is needed to address assets in poor condition or is obsolete. The investment is expected to mitigate risk of equipment failure and maintain supply reliability to Hydro One customers in the Ottawa area.	2	0	21
T-SR-03.91	Clarabelle TS	• This investment involves the replacement of 230/44kV 125MVA step-down transformers. • This investment is needed to address equipment that is in poor condition. The investment is expected to maintain existing system reliability. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure and removal of legacy obsolete equipment.	2	2	0
T-SR-03.92	Tomken TS	• This investment involves the replacement of 44 kV low voltage switchgear and protection and control equipment. This investment is needed to address equipment that is in poor condition. The investment is required to maintain supply reliability to the local customers supplied by this station, and mitigate the risk of outages and supply interruptions due to assets failure.	0	26	0
T-SR-03.93	Malvern TS	• This investment involves the replacement of a 230/27.6kV 75/125MVA power transformer, 27.6kV capacitor banks, and protection and control system upgrades. • The investment is needed to address the poor condition and performance of the transformer and capacitor banks, and the obsolete protection and control equipment. This investment is expected to maintain supply reliability to local customers (Toronto Hydro and Elexicon), and mitigate the risk of outages and supply interruptions due to asset failure.	1	0	17
T-SR-03.94	Allanburg TS	• The investment involves the replacement of an autotransformer, associated surge arrestors and disconnect switches. • This investment is needed to address equipment that is in poor condition. • The investment is expected to maintain existing system reliability and load serving capability of the	1	0	0

		system and is not meant for system capacity increase purposes. This investment is expected to reinforce the transmission system in the area, maintain reliability to the bulk system and major industrial customers and mitigate the risk of outages and supply interruptions due to asset failure.			
T-SR-03.95	Caledonia TS	• This investment involves the replacement of a 230/27.6 kV station supply transformer, breaker and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain supply reliability to the local customers supplied by this station, and mitigate the risk of outages and supply interruptions due to asset failure.	1	1	9
T-SR-03.96	Finch TS	• This investment involves the replacement of the low voltage switchyard and components including 28kV breakers, switches, capacitors, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	15	34
T-SR-03.97	Tomken TS	• This investment involves the replacement of step-down transformers and station infrastructure including spill containment. • This investment is needed to address the poor condition of the T1 and T2 transformers. This investment is expected to maintain long-term supply reliability to Alectra customers, and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	0
T-SR-03.98	Murray TS	• This investment involves the replacement of power transformers. • This investment is needed to address equipment that is in poor condition. This investment is expected to maintain reliability to the local area customers and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	0
T-SR-03.99	Lake TS	• This investment involves the replacement of all legacy medium voltage switching facilities at Lake TS that includes the air insulated switchyard and the legacy metalclad switchgear. • This investment is needed to address equipment that is in poor condition or is obsolete. In addition, the existing medium voltage switching facilities that presents health and safety challenges during routine maintenance. This investment is expected to maintain long-term supply reliability to Alectra Utilities customers and reduce the risk of unplanned outages due to asset failure.	0	27	7
T-SR-03.100	Stratford TS	• This investment involves the replacement of the 27.6kV switchyard and protection and control equipment. This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to decrease risk of equipment failure and maintain long-term reliability of supply to Hydro	0	13	30

		One Distribution and Festival Hydro Inc. customers in the town of Stratford and surrounding area.			
T-SR-03.101	Bramalea TS	• This investment involves the replacement of 44kV Breakers, 28kV breakers, capacitors, DC station service, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure	0	4	67
T-SR-03.102	Fergus TS	• This investment involves the replacement of transformers, oil circuit breakers, associated disconnect switches, and instrument transformers. • This investment is needed to address equipment that is in poor condition or is obsolete. • Kitchener Waterloo Cambridge Guelph Region's Integrated Regional Resource Plan (IRRP) notes the need of this investment. Fergus TS is one of the critical stations to serve the load in Fergus and surrounding areas. The investment will mitigate risks of transformer and other component failure at the station.	2	8	0
	Total		**151**	**609**	**1570**

APPENDIX B – DETAILED INVESTMENT COSTS

The investments proposed in this ISD are complex, and are undertaken over several years according to the Capital Project Delivery Model discussed in TSP Section 2.10. As the scope, design and execution are further defined throughout the process, cost and schedule accuracy improves. The table below summarizes the capital expenditures for each investment and presents the maturity of the project at the time of filing, where Execution (E) reflects fully approved project work and Planning and Definition (P) reflects non-execution work, regardless of level of upfront development.

Table 4 – Capital Expenditures

ISD Ref.	Station Name	EB-2019-0082	Type	Net Capital Investment ($ Millions)							In Service Year
				2023	2024	2025	2026	2027	23-27 Total	Project Total	
T-SR-03.01	Parry Sound TS	SR-05	E	8.2	0.0	0.0	0.0	0.0	8.2	23.0	2022
T-SR-03.02	Port Colborne TS	SR-02	E	9.2	0.0	0.0	0.0	0.0	9.2	31.0	2022
T-SR-03.03	Main TS	SR-05	E	4.0	0.0	0.0	0.0	0.0	4.0	33.9	2023
T-SR-03.04	Wilson TS	SR-05	P	14.3	0.0	0.0	0.0	0.0	14.3	41.4	2023
T-SR-03.05	Wonderland TS	SR-02	P	7.1	0.0	0.0	0.0	0.0	7.1	24.7	2023
T-SR-03.06	Moose Lake TS	SR-05	P	3.1	2.8	0.6	0.0	0.0	6.5	8.8	2023

Witness: REINMULLER Robert

T-SR-03.07	Orangeville TS	SR-05	E	10.3	4.7	0.0	0.0	0.0	15.0	34.5	2023
T-SR-03.08	Lambton TS	SR-02	P	17.0	0.0	0.0	0.0	0.0	17.0	47.7	2023
T-SR-03.09	Crowland TS	SR-05	P	9.5	10.0	0.0	0.0	0.0	19.5	35.8	2023
T-SR-03.10	Slater TS	SR-02	E	7.6	8.3	0.0	0.0	0.0	15.9	29.0	2023
T-SR-03.11	Lincoln Heights TS	-	P	14.0	2.9	0.0	0.0	0.0	16.9	21.4	2023
T-SR-03.12	Arnprior TS	SR-02	E	13.5	0.0	0.0	0.0	0.0	13.5	28.3	2023
T-SR-03.13	John TS	-	P	10.4	7.7	0.0	0.0	0.0	18.1	20.9	2024
T-SR-03.14	Rexdale TS	SR-06	E	8.5	6.3	0.0	0.0	0.0	14.9	29.3	2024
T-SR-03.15	Kirkland Lake TS	SR-06	P	7.5	6.6	0.0	0.0	0.0	14.1	27.7	2024
T-SR-03.16	Fairbank TS	SR-02	E	13.1	12.3	6.7	0.0	0.0	32.2	68.4	2024
T-SR-03.17	Bridgman TS	SR-05	E	16.8	13.7	0.0	0.0	0.0	30.5	65.2	2024
T-SR-03.18	Murray TS	SR-05	P	18.9	17.1	0.0	0.0	0.0	36.0	39.3	2024
T-SR-03.19	Lauzon TS	SR-05	P	20.8	15.8	0.0	0.0	0.0	36.6	41.2	2024
T-SR-03.20	Longueuil TS	SR-05	P	8.5	6.4	0.0	0.0	0.0	14.9	17.0	2024

T-SR-03.21	Bridgman TS	-	P	3.8	2.7	0.0	0.0	0.0	6.5	3.7	2024
T-SR-03.22	Riverdale TS	-	P	2.8	3.8	0.0	0.0	0.0	6.6	7.0	2024
T-SR-03.23	Port Arthur TS #1	SR-06	P	9.9	9.8	3.2	0.0	0.0	22.9	24.2	2025
T-SR-03.24	Port Hope TS	SR-05	P	7.3	7.4	8.8	0.0	0.0	23.6	23.8	2025
T-SR-03.25	Manby TS	-	P	4.1	7.7	3.9	0.0	0.0	15.7	16.8	2025
T-SR-03.26	Elliot Lake TS	SR-05	P	7.3	8.0	5.4	0.0	0.0	20.7	23.5	2025
T-SR-03.27	Preston TS	SR-05	P	4.8	10.9	6.4	0.0	0.0	22.1	22.9	2025
T-SR-03.28	Wallace TS	SR-05	P	4.3	7.8	5.8	1.6	0.0	19.7	20.3	2025
T-SR-03.29	Bermondsey TS	SR-05	P	3.6	10.4	5.9	0.0	0.0	19.8	20.6	2025
T-SR-03.30	Scarboro TS	-	P	1.6	4.7	2.8	0.0	0.0	9.1	9.7	2025
T-SR-03.31	Newton TS	-	P	4.5	4.1	2.3	0.0	0.0	11.0	12.6	2025
T-SR-03.32	St. Andrews TS	SR-02	P	5.1	19.0	19.2	0.0	0.0	43.3	43.8	2025
T-SR-03.33	Picton TS	-	P	1.3	7.4	4.8	0.0	0.0	13.5	14.0	2025
T-SR-03.34	Midhurst TS	-	P	1.4	3.8	2.8	0.6	0.0	8.7	9.2	2025

Witness: REINMULLER Robert

T-SR-03.35	Orillia TS	-	P	0.7	4.0	2.8	0.0	0.0	7.5	8.0	2025
T-SR-03.36	Bracebridge TS	-	P	0.7	3.6	2.9	0.4	0.0	7.6	8.0	2026
T-SR-03.37	Charles TS	SR-05	P	3.2	10.9	11.6	3.7	0.0	29.4	30.1	2026
T-SR-03.38	Manby TS	-	P	4.0	5.9	6.2	4.5	0.0	20.6	21.0	2026
T-SR-03.39	Russell TS	SR-05	P	1.0	7.6	10.7	4.9	0.0	24.2	24.4	2026
T-SR-03.40	Duplex TS	SR-05	P	1.2	7.1	9.8	3.8	0.0	21.8	22.5	2026
T-SR-03.41	Lake TS	SR-06	P	8.5	11.2	7.8	3.4	0.0	30.9	33.8	2026
T-SR-03.42	Bunting TS	SR-06	P	2.7	8.9	17.8	6.6	0.0	36.0	41.0	2026
T-SR-03.43	Nebo TS	-	P	0.3	1.6	9.5	7.6	0.0	19.0	19.0	2026
T-SR-03.44	Palermo TS	SR-05	P	0.7	3.4	12.7	2.6	0.0	19.4	19.5	2026
T-SR-03.45	Carlton TS	SR-02	P	6.6	12.2	14.5	-0.1	0.0	33.2	36.0	2026
T-SR-03.46	Birmingham TS	SR-05	P	1.0	3.4	13.2	7.9	0.0	25.5	25.7	2026
T-SR-03.47	Carling TS	-	P	0.2	0.6	3.2	4.9	0.0	8.9	8.9	2026
T-SR-03.48	Cherrywood TS	SR-06	P	0.6	1.4	8.0	5.2	0.0	15.3	15.6	2026

Witness: REINMULLER Robert

T-SR-03.49	Gage TS	SR-05	P	0.7	3.0	12.1	8.3	0.7	24.9	25.1	2026
T-SR-03.50	Woodbridge TS	SR-05	P	0.6	0.9	5.2	4.7	1.0	12.4	12.6	2027
T-SR-03.51	Fairchild TS	SR-05	P	0.7	3.4	14.9	16.8	4.5	40.2	40.5	2027
T-SR-03.52	Cedar TS	SR-05	P	1.4	5.0	8.2	6.5	1.9	23.0	23.6	2027
T-SR-03.53	Halton TS	SR-07	P	0.5	0.6	2.7	4.4	1.9	10.1	10.3	2027
T-SR-03.54	Waubaushene TS	-	P	0.5	1.0	3.9	8.1	4.2	17.7	17.8	2027
T-SR-03.55	Kent TS	SR-02	P	0.5	1.2	5.4	13.5	7.4	28.0	28.1	2027
T-SR-03.56	Muskoka TS	SR-06	P	0.3	0.6	1.4	3.5	1.8	7.6	7.6	2027
T-SR-03.57	Timmins TS	-	P	0.2	0.6	1.3	4.0	2.3	8.5	8.5	2027
T-SR-03.58	Glendale TS	SR-02	P	7.3	9.3	12.0	11.5	7.3	47.4	55.0	2027
T-SR-03.59	Vansickle TS	SR-06	P	0.3	0.7	1.4	5.6	3.4	11.4	14.5	2027
T-SR-03.60	Dundas TS	SR-06	P	0.2	0.6	1.1	5.9	3.7	11.5	11.5	2027
T-SR-03.61	Mohawk TS	SR-06	P	0.2	0.5	0.9	5.0	3.2	9.8	9.8	2027
T-SR-03.62	Bathurst TS	SR-05	P	0.3	0.6	1.7	9.2	5.8	17.5	17.5	2027

Witness: REINMULLER Robert

T-SR-03.63	Leslie TS	SR-05	P	0.3	0.6	3.2	18.1	11.8	33.9	33.9	2027
T-SR-03.64	Burlington TS	SR-06	P	0.4	0.5	1.4	5.4	3.7	11.3	11.6	2027
T-SR-03.65	Alliston TS	-	P	0.2	0.6	1.4	7.9	6.5	16.7	17.7	2028
T-SR-03.66	Dobbin TS	-	P	1.9	9.8	24.5	33.4	23.8	93.5	100.8	2028
T-SR-03.67	Strachan TS	SR-05	P	0.2	0.8	3.8	16.3	16.3	37.4	42.0	2028
T-SR-03.68a	Clarke TS	-	P	0.2	0.6	1.7	9.4	8.6	20.4	22.3	2028
T-SR-03.68b	Clarke TS	SR-05	P	0.2	0.6	1.9	10.7	9.7	23.1	25.2	2028
T-SR-03.69	Albion TS	-	P	0.2	0.6	2.6	15.7	19.2	38.3	44.9	2028
T-SR-03.70	Bilberry Creek TS	SR-05	P	0.2	0.6	1.5	8.7	10.6	21.5	25.1	2028
T-SR-03.71	Talbot TS	-	P	0.2	0.6	1.6	9.9	12.1	24.5	28.6	2028
T-SR-03.72	Havelock TS	-	P	0.1	0.5	1.1	6.1	8.6	16.5	19.9	2028
T-SR-03.73	Lisgar TS	-	P	0.0	0.7	0.8	3.8	5.4	10.6	12.7	2028
T-SR-03.74	Duplex TS	-	P	0.1	0.5	1.1	6.4	10.4	18.5	23.1	2028
T-SR-03.75	Crystal Falls TS	-	P	0.1	0.5	1.5	8.4	11.1	21.7	27.8	2028

T-SR-03.76	Douglas Point TS	-	P	0.1	0.4	1.4	7.7	11.3	21.0	28.0	2028
T-SR-03.77	Trout Lake TS	-	P	0.0	0.6	0.9	4.6	9.0	15.0	19.4	2028
T-SR-03.78	Lauzon TS	-	P	0.0	0.5	1.3	7.8	15.1	24.7	32.8	2028
T-SR-03.79	Galt TS	-	P	0.0	0.5	0.6	2.5	6.0	9.6	12.8	2028
T-SR-03.80	Martindale TS	-	P	0.5	0.9	3.3	7.2	7.9	19.7	23.2	2028
T-SR-03.81	Bruce B HWP TS	-	P	0.0	0.5	0.8	4.6	13.7	19.5	27.4	2028
T-SR-03.82	Campbell TS	SR-06	P	0.0	0.2	1.1	7.2	7.1	15.6	18.1	2028
T-SR-03.83	Bramalea TS	-	P	0.1	0.4	0.5	2.5	9.7	13.3	19.1	2028
T-SR-03.84	Erindale TS	SR-07	P	0.0	0.3	0.6	2.2	12.1	15.1	23.0	2028
T-SR-03.85	Gardiner TS	-	P	0.0	0.3	0.7	2.5	13.8	17.2	26.2	2028
T-SR-03.86	Morrisburg TS	-	P	0.0	0.0	0.2	0.6	3.7	4.5	10.2	2028
T-SR-03.87	Nepean TS	-	P	0.0	0.3	0.6	1.5	8.6	11.0	16.6	2028
T-SR-03.88	Beach TS	-	P	0.0	0.2	0.6	8.3	15.0	24.2	40.4	2028
T-SR-03.89	Port Arthur TS #1	-	P	0.2	0.5	0.9	2.9	3.9	8.4	10.4	2028

Witness: REINMULLER Robert

T-SR-03.90	South March TS	-	P	0.0	0.3	0.6	1.9	10.5	13.3	20.1	2028
T-SR-03.91	Clarabelle TS	-	P	0.0	0.3	0.6	1.7	9.4	11.9	18.0	2028
T-SR-03.92	Tomken TS	-	P	0.0	0.2	0.6	1.9	11.3	14.1	23.3	2029
T-SR-03.93	Malvern TS	-	P	0.0	0.3	0.7	1.6	6.7	9.3	15.3	2029
T-SR-03.94	Allanburg TS	-	P	0.0	0.2	0.5	1.1	4.3	6.1	10.7	2029
T-SR-03.95	Caledonia TS	-	P	0.0	0.2	0.5	1.1	4.1	5.9	10.2	2029
T-SR-03.96	Finch TS	SR-06	P	0.0	0.2	0.6	1.8	5.2	7.9	32.0	2029
T-SR-03.97	Tomken TS	-	P	0.0	0.2	0.6	1.4	6.5	8.6	24.0	2029
T-SR-03.98	Murray TS	-	P	0.0	0.2	0.6	1.0	5.3	7.1	17.3	2029
T-SR-03.99	Lake TS	-	P	0.0	0.3	0.9	3.4	8.8	13.4	25.3	2029
T-SR-03.100	Stratford TS	-	P	0.0	0.1	0.5	1.3	7.2	9.2	25.1	2029
T-SR-03.101	Bramalea TS	SR-07	P	0.0	0.0	0.3	0.9	3.9	5.2	27.2	2030
T-SR-03.102	Fergus TS	-	P	0.0	0.0	0.1	0.6	1.4	2.1	26.1	2030
Net Investment Cost				**334.5**	**357.7**	**350.1**	**406.5**	**428.6**	**1877.3**	**2534.6**	

Witness: REINMULLER Robert

HONI NOTIFICATION TO OEB - REQUEST FOR APPROVAL OF INTENTION TO USE THE REGULATORY ACCOUNT

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Director
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BY EMAIL AND RESS

July 9, 2025

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

Dear Ms. Marconi,

Re: EB-2021-0169- Hydro One Networks Inc. ("Hydro One") Request for Approval of Intention to Use the Regulatory Account for New Affiliate Transmission Line Project – New 230kV Supply to Welland Area

Background

On October 7, 2021, the Ontario Energy Board ("OEB") approved Hydro One Networks Inc.'s ("Hydro One") Application for an Accounting Order[1] establishing the Affiliate Transmission Project Regulatory Account ("ATP Account", or "Account").

The OEB approved the ATP Account to be used to track expenditures on transmission line projects where Hydro One expects that the line project component will not be included in Hydro One's future transmission rate base and consequently is expected to be included in the rate base and future revenue requirement application of a new licensed transmitter.

The Independent Electricity System Operator ("IESO") has recommended in its Niagara Integrated Regional Resource Plan (IRRP)[2], dated December 22, 2022, to initiate development work for the replacement of the existing 115 kV station Crowland TS with a new 230 kV station that is supplied by a new 230 kV double-circuit transmission line connected to the existing 230 kV system in the Welland area, jointly hereafter referred to as the Welland Thorold Powerline Project or the Project. The Project is required prior to 2028. There has been no change to this recommendation from the IESO. Furthermore, Hydro One is the only transmitter that can address this system need given that this Project does not meet the eligibility criteria currently contemplated in the Transmitter Selection Framework[3], specifically the lead-time criteria, and because the Project encompasses the replacement of end-of-life Hydro One infrastructure. Hydro One submits for the OEB's concurrence that the IRRP recommendation from the IESO is akin to the criteria established for the ATP Account.

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[1] Attachment 1 – OEB Approval of Accounting Order for Establishment of ATP Account.
[2] Attachment 2- IESO Niagara Integrated Regional Resource Plan dated December 22, 2022.
[3] IESO Presentation - TSF Update and Qualified Transmitter Registry (QTR) Design, p. 10 – January 22, 2025, available at this link: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/tsf/TSF-20250122-Presentation.pdf

Currently Hydro One has informed the OEB of its intentions to record activities for the following transmission line projects in the ATP Account:

1. Waasigan Transmission Line project[4]

2. Chatham to Lakeshore Transmission Line project[5]

3. Lambton to Chatham Transmission Line project, which was renamed the St. Clair Transmission Line ("SCTL") project, described as a new 230 kilovolt ("kV") transmission line from Lambton Transformer Station to Chatham Switching Station, including associated station facility expansions or upgrades required at the terminal stations[6]

4. A new 500 kV transmission line from Longwood Transformer Station to Lakeshore Transformer Station, including associated station facility expansions or upgrades required at the terminal stations[7]

5. A second new 500 kV transmission line from Longwood Transformer Station to Lakeshore Transformer Station, including associated station facility expansions or upgrades required at the terminal stations[8]

6. A new 230 kV transmission line that connect the Windsor area to the Lakeshore Transformer Station, including associated station facility expansions or upgrades required at the terminal stations[9]

7. A new 230 kilovolt (kV) transmission line from Mississagi Transformer Station to Third Line Transformer Station, which has been renamed the North Shore Link ("NSL") project, including associated station facility expansions or upgrades required at the terminal stations[10]

8. A new 500 kV transmission line from Mississagi Transformer Station to Hanmer Transformer Station, which has been renamed the North-East Power Line ("NEPL") project, including associated station facility expansions or upgrades required at the terminal stations[11], and

9. A new 230 kV transmission line from Dobbin Transformer Station to either Cherrywood Transformer Station or Clarington Transformer Station, which has been renamed the Durham Kawartha Power

[4] This project has received OEB s.92 Approval - EB-2023-0198.
[5] This project has received OEB s.92 Approval - EB-2022-0140.
[6] This project has received OEB s.92 approval – EB-2024-0155.
[7] EB 2022-0142- HONI ATP Account Projects
[8] EB 2022-0142- HONI ATP Account Projects
[9] EB 2022-0142- HONI ATP Account Projects
[10] EB-2023-0319 - Notification to OEB of NE Ontario and GTA East
[11] EB-2023-0319 - Notification to OEB of NE Ontario and GTA East

Line Project, including associated station facility expansions or upgrades required at the terminal stations[12].

Request

Hydro One is requesting the OEB approve the use of the ATP Account for the Project, described as:

1. A new 230 kilovolt (kV) transmission line from Allanburg TS to Crowland TS, alongside the existing 115 kV transmission corridor.

The Project listed above meets the criteria for inclusion in the ATP Account for the following reasons:

a.) Initiation of development has been recommended by the IESO through the Niagara IRRP;
b.) All or part of the project is expected to be owned by and included in the rate base of a new partnership between Hydro One and one or more partners, as a licensed transmitter, and will not form part of Hydro One's rate base; and
c.) The total development and construction costs for the Project significantly exceeds Hydro One's materiality threshold.

Hydro One will track costs for the Project being added to the ATP Account in a separate sub-account and manage the sub-account in the same manner as those already approved in EB-2021-0169, EB-2022-0142, EB-2023-0319, and EB-2024-0361.

Sincerely,

Pasquale Catalano

cc:

c/ Intervenors of record in EB-2021-0169 (electronic only)
c/ IESO

[12] EB-2023-0319 - Notification to OEB of NE Ontario and GTA East

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PROJECT SCHEDULE

TASK	START	FINISH
Section 92 Approval	NOV-2025	MAY-2026
LINES		
Receipt of Other Key Permits and Approvals	NOV-2024	SEP-2026
Voluntary Property Rights Acquisition[1]	NOV-2025	AUG-2026
Detailed Engineering	FEB-2025	MAR-2026
Procurement	OCT-2025	JUN-2027
Construction	SEP-2026	DEC-2028
Commissioning	JAN-2029	AUG-2029
In Service	N/A	AUG-2029
Site Remediation Completion	N/A	DEC-2030
STATIONS[2]		
Receipt of Other Key Permits and Approvals	NOV-2024	JUN-2026
Voluntary Property Rights Acquisition[1]	N/A	N/A
Detailed Engineering	FEB-2025	MAR-2026
Procurement	JUL-2025	JUN-2027
Construction	JUN-2026	DEC-2028
Commissioning	JAN-2029	AUG-2029
In Service	N/A	AUG-2029
Site Remediation Completion	N/A	DEC-2030

[1] Completion timing is dependent upon property owner-specific negotiations. The above schedule does not include the expropriation schedule
[2] This schedule excludes Crowland SS as it is treated as a separate project.

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DESCRIPTIONS OF THE PHYSICAL DESIGN

1.0 ROUTE DESCRIPTION

The proposed 230 kV/115 kV double and triple-circuit transmission line will be located in the Municipalities of Welland, Thorold, and City of Niagara. The line will run from Abitibi Consolidated Junction and terminate at Crowland TS. The total line length of the Project is approximately 18.5 km and will utilize a ROW nominally 30 m wide.

1.1 ROUTE DETAILS

i. Segment A of the route begins at the location of a proposed connection to an existing 230kV transmission line, located approximately at Abitibi Consolidated Junction, in the City of Thorold, and proceeds south to the Allanburg TS for roughly 3.5 km. This segment is a net-new corridor (greenfield) and proceeds south from the connection to the existing transmission line parallel to Thorold Townline Road along the existing transmission line corridor for approximately 1.75 km before crossing Thorold Townline Road to the east, proceeding for 0.9 km, and crossing the Thorold Townline Road to the west for the duration of the line.

ii. Segment B of the route begins near Allanburg TS, the route proceeds south for approximately 8 km along the existing 115 kV transmission line corridor until Michigan Junction.

iii. Segment C of the route initiates from Michigan Junction, then proceeds southwest in a net-new corridor for approximately 1.5 km before rejoining the existing idle 115kV corridor for approximately 5.5 km before terminating at Crowland TS. This route includes repurposing an existing idle 115 kV transmission corridor.

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

2.0 LINE DESCRIPTION

The 230 kV/115 kV transmission line will have two circuits for Segment A and C (two 230 kV circuits), while Segment C will also contain a three-circuit arrangement (two 230 kV circuits, one 115 kV circuit). The 230 kV circuits will be comprised of one 1433.6 kcmil ACSS/TW "Merrimack" conductor per phase, while the 115 kV circuit in Segment B will be comprised of one 411 kcmil ACSR/TW "Simcoe" conductor per phase, primarily supported on self-supporting steel lattice towers. Further, the 230 kV double circuit transmission line (Sections A and C) will have the following attributes:

i. The line will have a continuous ampacity of 1132.2A (summer 35C);
ii. Glass insulators will be used for both suspension and tension applications in accordance with Hydro One standards;
iii. Stockbridge-type vibration dampers to dampen the conductor in accordance with Hydro One standard, based on the final line configuration and per the manufacturer's design;
iv. Stockbridge-type vibration dampers to dampen the OPGW/shieldwire;
v. Typical structure foundations will be helical pile type;
vi. The double circuit segments of the line will make use of 30 self-supported lattice suspension towers with nominal spans of approximately 230 m (refer to Figure 1). There will also be 27 heavy angle and other special structures used for infrastructure crossings and points of inflection (refer to Figure 2).

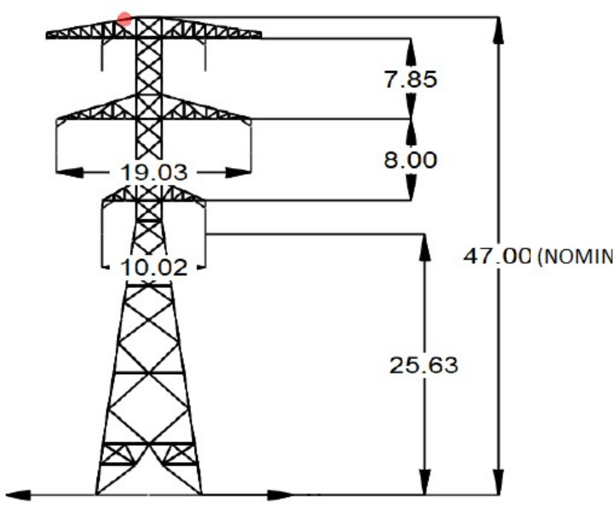

Figure 1: Suspension Tower

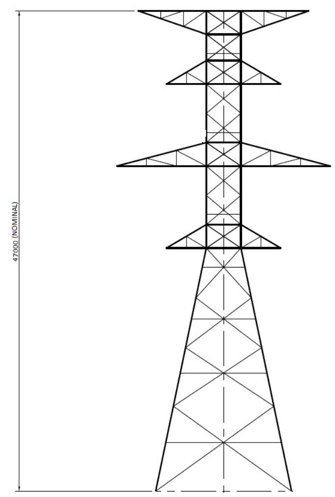

Figure 2: Heavy Angle

Additionally, the 230 kV/115 kV triple circuit transmission line (Section B) will have the following attributes:

i. The 1433.6 kcmil ACSS/TW "Merrimack" conductor will have a continuous ampacity of 1132.2A (summer 35C);

ii. The 411 kcmil ACSR/TW "Simcoe" conductor will have a continuous ampacity of 499.6A (summer 35C);

iii. Glass insulators will be used for both suspension and tension applications in accordance with Hydro One Standards;

iv. Stockbridge-type vibration dampers to dampen the conductor in accordance with Hydro One standard, based on the final line configuration and per the manufacturer's design;

v. Stockbridge-type vibration dampers to dampen the OPGW/shieldwire;

vi. Typical structure foundations will be helical pile type;

vii. The double circuit segments of the line will make use of 27 self-supported lattice suspension towers with nominal spans of approximately 230 m (refer to Figure 3). There will also be 7 heavy angle structures used for infrastructure crossings and points of inflection (refer to Figure 4);

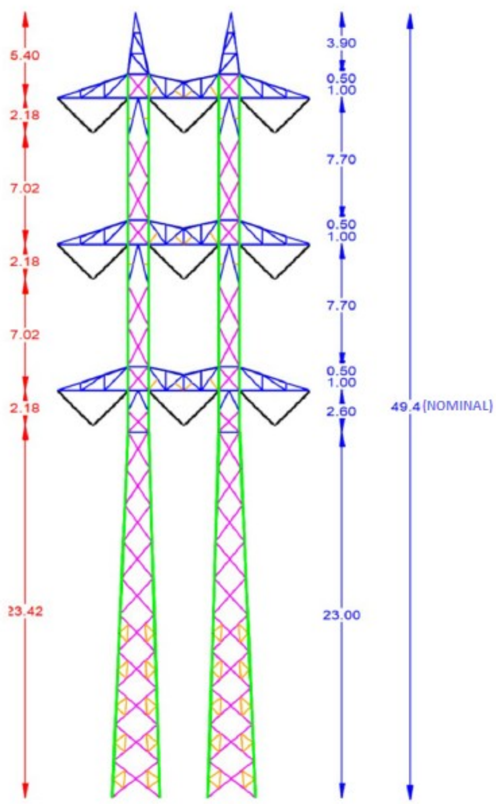

Figure 3: Suspension Tower

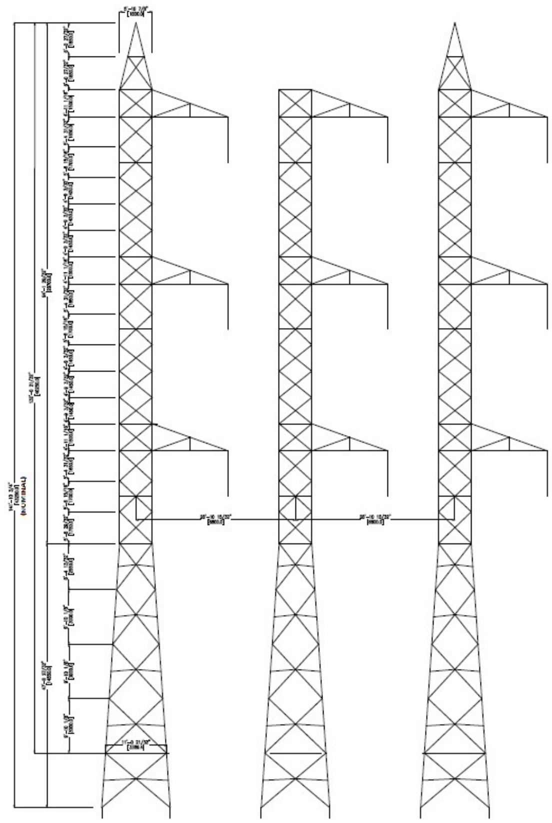

Figure 4: Heavy Angle

3.0 LINE REMOVAL

The Project will repurpose approximately 15 km (Sections B and C) of an existing 115 kV transmission line corridor as defined through the completed Class EA process and include the removal of sections of the existing 115kV single-circuit transmission line (D3A/A3C, A1C/A3C) including 52 transmission structures, conductor and associated components.

4.0 STATION WORK

The transmission station work will consist of terminal station modifications at Crowland TS, protection modifications at remote stations (Allanburg TS, Beck TS, and Port Colborne TS). The following outlines the specific work required at each of the stations:

Crowland TS

- Conversion of the existing station from 115 kV to 230 kV to enable connection to the new 230 kV transmission line
    - Construction of a new 230kV/27.6kV DESN Station with two (2) new 230kV/27.6kV 75/100MVA transformers, ten (10) 27.6kV feeder breakers, one (1) 27.6kV bus tie breaker, four (4) 27.6kV transformer bank breakers, two (2) spare feeder positions, and the provision for a future 27.6kV capacitor bank;
    - Install new bus work, ground switches, protection, control, and telecommunications, and operational metering, including one new relay building;
    - Excavation and removal of existing above and below grade infrastructure in the new station area;
    - Expand the station property on the south east side to accommodate the new DESN Station;
    - The transfer of all feeders from the existing 115kV/27.6kV station to the new 230kV/27.6kV station; and
    - The removal of the existing 115kV/27.6kV station equipment.

Remote Stations (Allanburg TS, Beck TS, Port Colbourne TS)

- Protection, control, and telecommunications modifications at remote stations to accommodate the new 230kV line and Crowland TS.

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OPERATIONAL DETAILS

The proposed facilities for the Project will be part of the Hamilton-Niagara transmission system and are required to provide reliable supply capacity in the area. Hydro One protection, control and telecom facilities installed as part of the Project will protect the proposed 230 kV double-circuit transmission line by detecting faults and isolating faulted elements. The proposed facilities will be operated by Hydro One's ISOC as directed by the IESO. The terminal station for the proposed 230 kV double-circuit transmission line is Crowland TS, with Allanburg TS connected to the 115kV circuit on the portion of the line that has three circuits, as aforementioned in the Application.

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LAND MATTERS

1.0 THE ROUTE

The proposed transmission line corridor will be 18.5 km in length and nominally 30m in width for the majority of the corridor, with some stretches varying up to 49m wide. The new corridor will impact approximately 72.34 hectares of land and will make use of approximately 18.42 hectares of land that is designated Bill 58 corridor lands (i.e., land owned by the Province with Hydro One holding a statutory easement on these lands) and 23.22 hectares of existing utility corridor lands where new rights will be required. The remaining 30.7 hectares of the transmission line corridor are comprised of private, federal, provincial, municipal, private and rail lands and are summarized in Table 1 below – Summary of Property Requirements.

The new transmission line aligns with the M*inistry of Municipal Affairs and Housing Provincial Policy Statement, 2024* in so far as the Project make use of existing infrastructure and facilities. Where possible, the existing transmission corridor lands noted above and the existing Rights of Way (ROW) are being used.

2.0 DESCRIPTION OF LAND RIGHTS

The Project will require Hydro One to acquire land rights from 65 directly impacted properties, consisting of 46 privately held properties, 3 federally held properties, 6 provincially held properties, 7 municipally held properties, and 3 railway crossings. Hydro One will require permanent interest from the property owners. Hydro One is working with directly impacted property owners to negotiate amicable voluntary agreements

. **Table 1 - Summary of Property Types and Sizes Required**

Land Ownership Type	Count	Area (Hectares)	Proportion of the Route (%)
Private Lands	46	37.54	52%
Brownfield	31	23.22	32%
Greenfield	15	14.32	20%
Federal Lands	3	5.75	8%
Provincial Lands	6	0.59	1%
Municipal Lands	7	4.53	6%
Railway Lands	3	0.47	1%
No New Rights Required			
Provincial Lands (Bill 58 - Hydro One owned land)	22	18.42	25%
Public Road Allowance	37	4.29	6%
Private Land Already Acquired	1	0.73	1%
Total	125	72.31	100%

3.0 MAPS OF THE PROJECT AREA

At **Exhibit B, Tab 2, Schedule 1, Attachment 1**, Hydro One has provided a map with the intention it be used as the Application's *Notice Map* should the OEB determine that a hearing is required. **Attachment 1 of this Schedule** provides a more detailed route map that illustrates properties along the 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:

- Hydro One License of Occupation on Federally owned lands and/or easements;
- Permanent Easement rights on private and municipal/provincial properties (new land rights required);
- Rail crossing agreements (new land rights required); and
- Temporary access and/or construction rights on federally, provincially, 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 access, construct, operate and maintain the transmission line in one or more of the agreements below. The type of agreement and form Hydro One will transact varies by owner and jurisdictional authority. The forms and agreements are:

- Early Access Agreement;
- Option to Purchase a Limited Interest – Permanent Easement;
- Compensation and Incentive Agreement – Permanent Easement;
- Rail Crossing Agreement (provided by rail company at a later date);
- Encroachment Permit (provided by Ministry of Transportation at a later date);
- Agreement for Temporary Rights;
- License of Occupation and/or Easements
- Off Corridor Access;
- Crop Land Out of Production Agreement; and
- Damage Claim Agreement/Waiver.

Where crossings of public roads and highways are contemplated and indicated in **Attachment 1 of this Schedule**, Hydro One will rely on the land rights afforded by section 41 of the *Electricity Act* (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*. All road crossings will be designed to meet or exceed CSA vertical clearance standards.

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 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. To facilitate the required access to the properties affected by the corridor in advance of Leave to Construct approval, Hydro One has been and will continue to enter into early access agreements with affected landowners. As of October 31st, 2025, Hydro One has achieved voluntary early access agreements on approximately **78**% of the private properties that require new land rights.

6.0 LAND ACQUISITION PROCESS

Hydro One is seeking voluntary property rights agreements with affected property owners based on its project-specific LACP. The LACP is founded upon Hydro One's past experience pertaining to land acquisition matters for new transmission projects and acts 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 receive fair and consistent compensation while balancing Hydro One's desire to achieve timely acquisition 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 April 2025. The objective of these meetings has been to introduce Hydro One's voluntary land acquisition process. A land value study estimate based on market analysis was developed by a third-party appraiser to provide an indication of expected land costs along the proposed corridor. Independent site-specific property appraisals are underway, and Hydro One is preparing voluntary property settlement offers based on the site-specific appraisals, and Hydro One's LACP. Once site specific appraisals are completed, Option Agreement Offers will be presented to landowners. Hydro One is aiming to present Option Agreement Offers to landowners in early December 2025. As part of the property negotiation and acquisition process, property owners that are offered Option Agreements advised that they have the option to receive reimbursement for reasonably incurred fees associated with i) retaining independent legal advice in connection with the review and execution of the necessary land rights agreements and ii) utilizing an accredited independent Appraiser to complete an additional site-specific appraisal, should the Property Owner have concerns with and/or disagree with the compensation offered in the Option Agreement.

Hydro One will continue working with each property owner with the objective of reaching voluntary settlements. Once Option Agreements are executed with a property owner, and after Hydro One has received the OEB's Leave to Construct approval of the Project, the Option Agreements will be exercised and Hydro One will register easements on title for properties.

All other applicable agreements (e.g. rail crossing agreements, 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 2 of this Schedule**.

Table 2 - Land Acquisition Status (As of October 31, 2025)

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

7.0 LAND-RELATED FORMS

Provided as **Attachments 3 through 12** of this Schedule**,** are the land right agreements that Hydro One intends to use for the Project Table 3 below identifies where the form of these agreements were previously approved and there are no substantive changes to the forms of the agreements proposed.

Table 3 - Forms of Agreement Remaining Unchanged

Form of Agreement	Attachment in this Schedule	Previous OEB Docket
Early Access Agreement	3	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 3
Option to Purchase a Limited Interest – Easement	4	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 4
Compensation and Incentive Agreement – Easement	5	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 5
Option to Purchase a Limited Interest – Easement with a Voluntary Buyout Offer	6	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 8
Agreement for Temporary Rights	7	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 9
Off Corridor Access	8	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 10
Crop Land Out of Production Agreement	9	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 11
Damage Claim Agreement/Waiver	10	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 12

8.0 EXPROPRIATION RELIEF

Unique to this Application, Hydro One is concurrently seeking expropriation relief for a finite number of the properties identified in **Attachment 2 of this Schedule** where Hydro One has identified title issues with lands necessary to deliver the Project. The expropriation relief sought is necessary as Hydro One's ability to secure voluntary land rights in these specific circumstances is either impossible, e.g., the identified property owner is deceased with no next of kin, or the title is susceptible to legal challenge based on the validity of the existing title.

A description of the lands and the specific interests in lands in which Hydro One is seeking authority to expropriate is attached in **Attachment 11 of this Schedule**. This list is inclusive of any interests Hydro One requires to access, construct, operate and maintain the Project. Hydro One has conducted a search of title sufficient to identify the current registered property owners, those who hold registrable interests in the lands, and those with any interest in the lands directly affected by this Application. The names of these individuals are listed, by property, in **Attachment 11 of this Schedule**. Personal information has been redacted in accordance with the OEB's Practice Direction. Hydro One notes that off-corridor temporary access land rights continue to be negotiated and secured on a voluntary basis as needed. Should there be a need to secure expropriation authority in the future to secure off-corridor land rights, Hydro One intends to make a separate application. For clarity off corridor lands that may be required are not listed in any of the Attachments to this application.

Additionally, attached hereto as **Attachment 12 of this Schedule** are copies of the reference plans, suitable for registration, showing the lands over which authority to expropriate the interests set out in **Attachment 11 of this Schedule** is being requested and the registered owners thereof.

As noted above, efforts to voluntarily secure permanent easement interest are ongoing with all registered property owners listed in Attachment 2. Hydro One reserves the right to seek expropriation authority over those lands in a future application should voluntary agreements not be executed.

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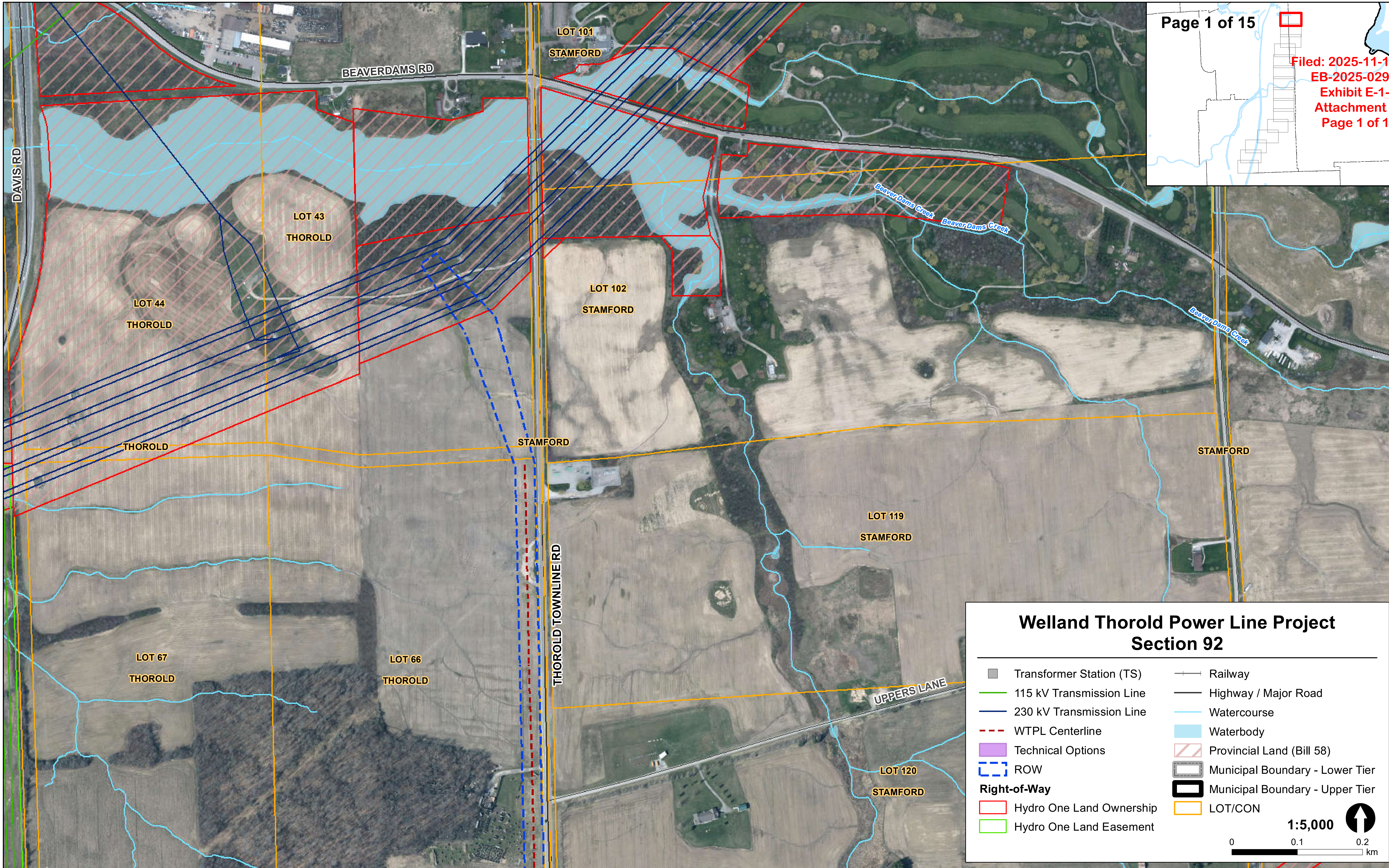

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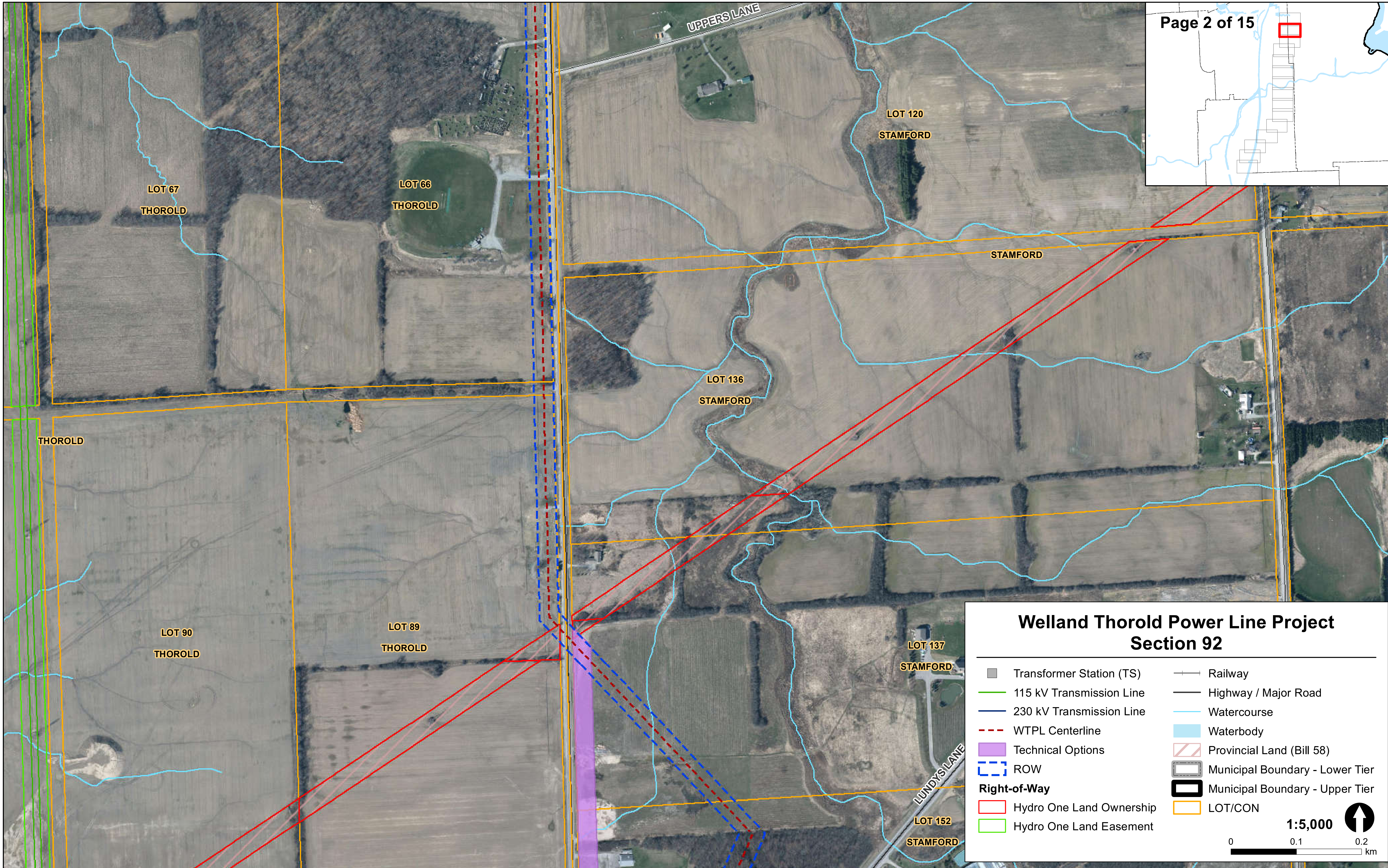

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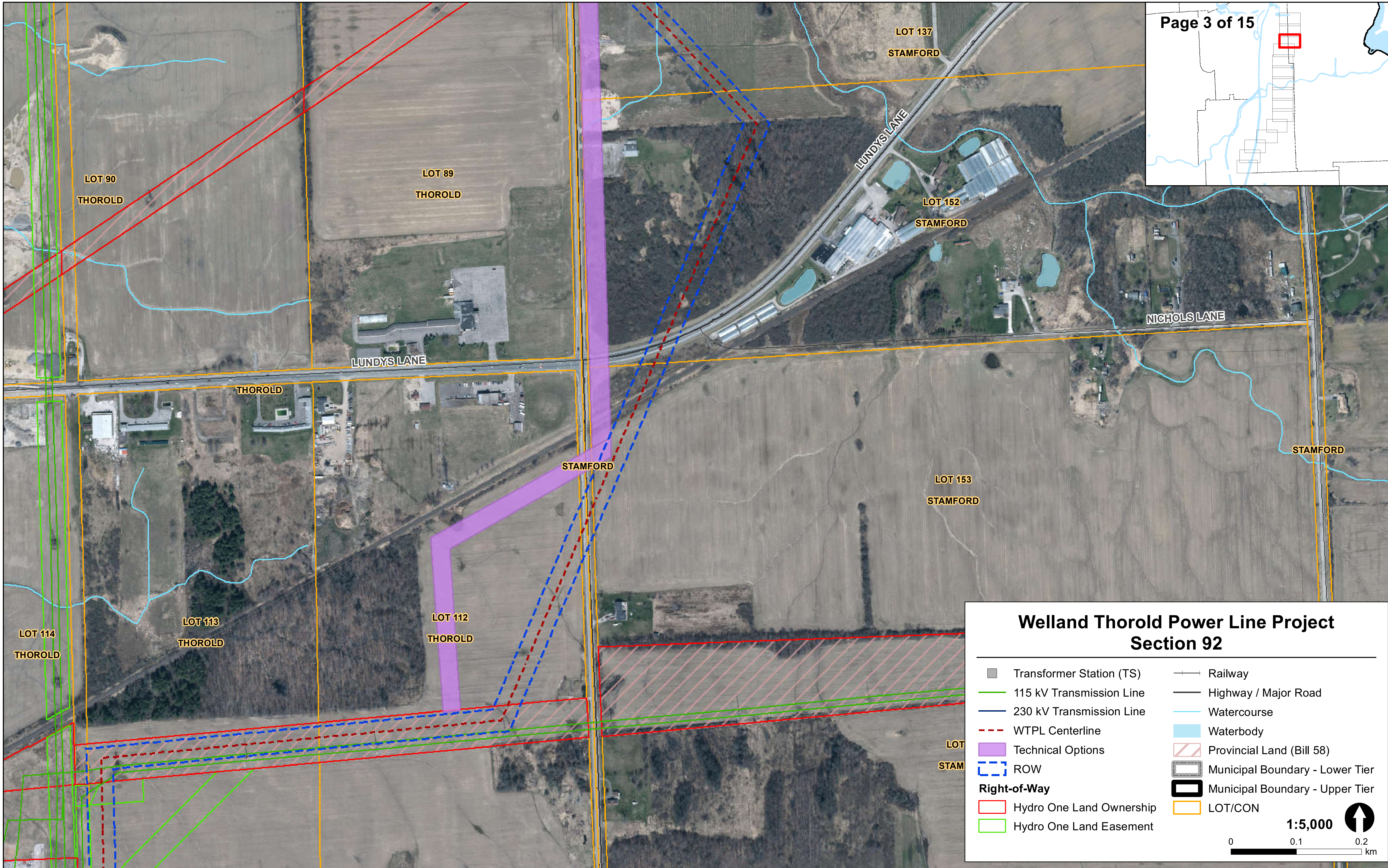

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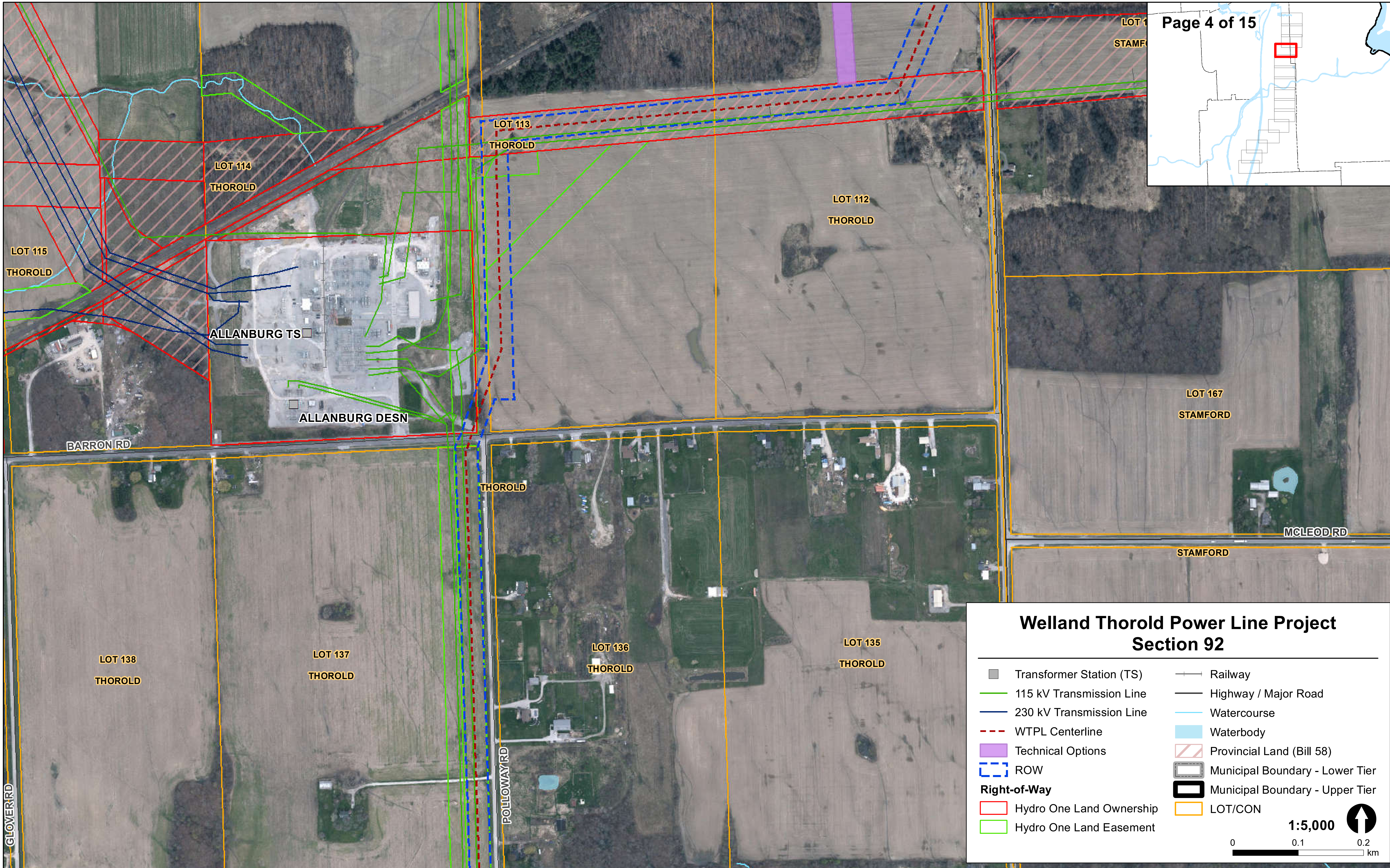

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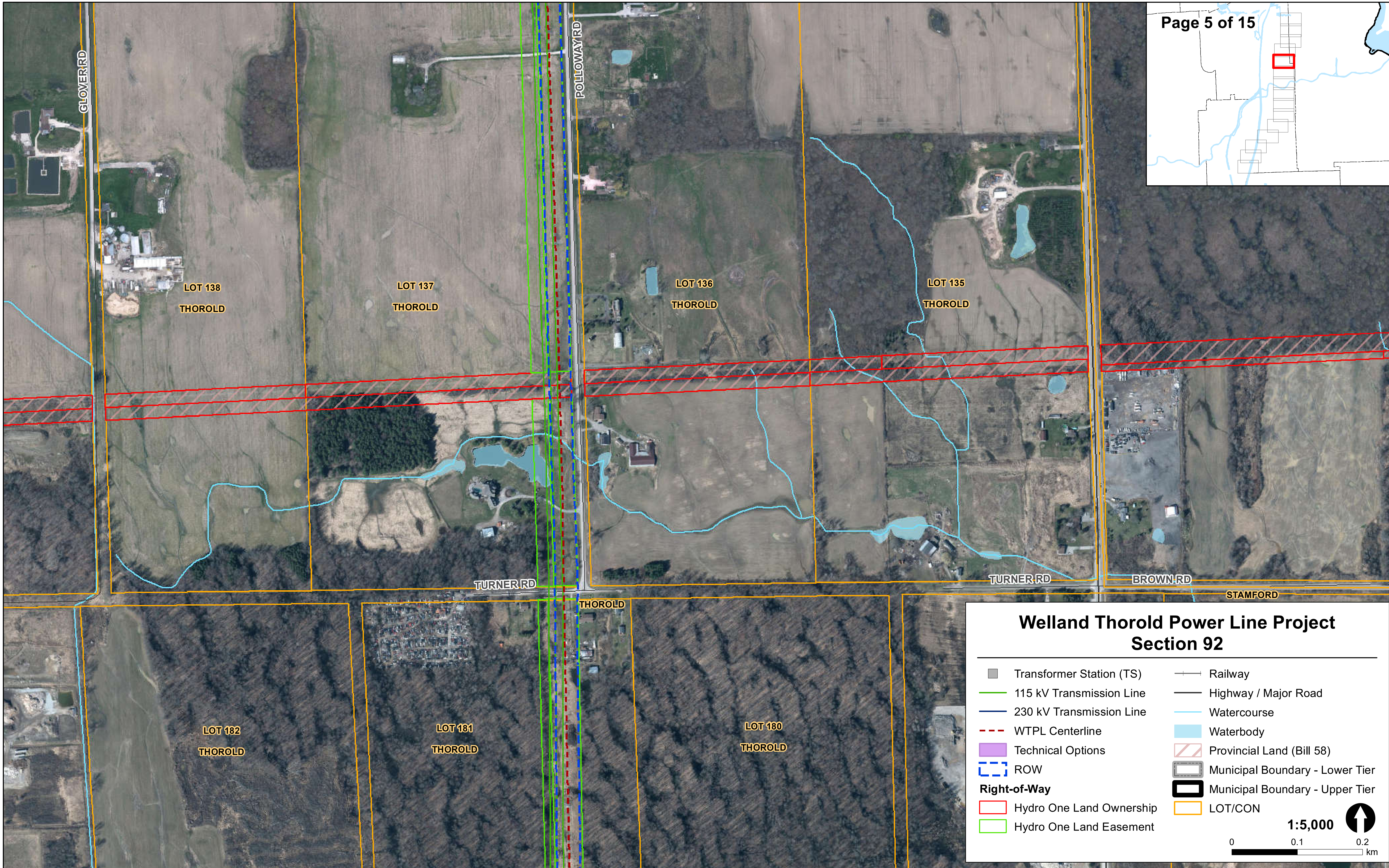

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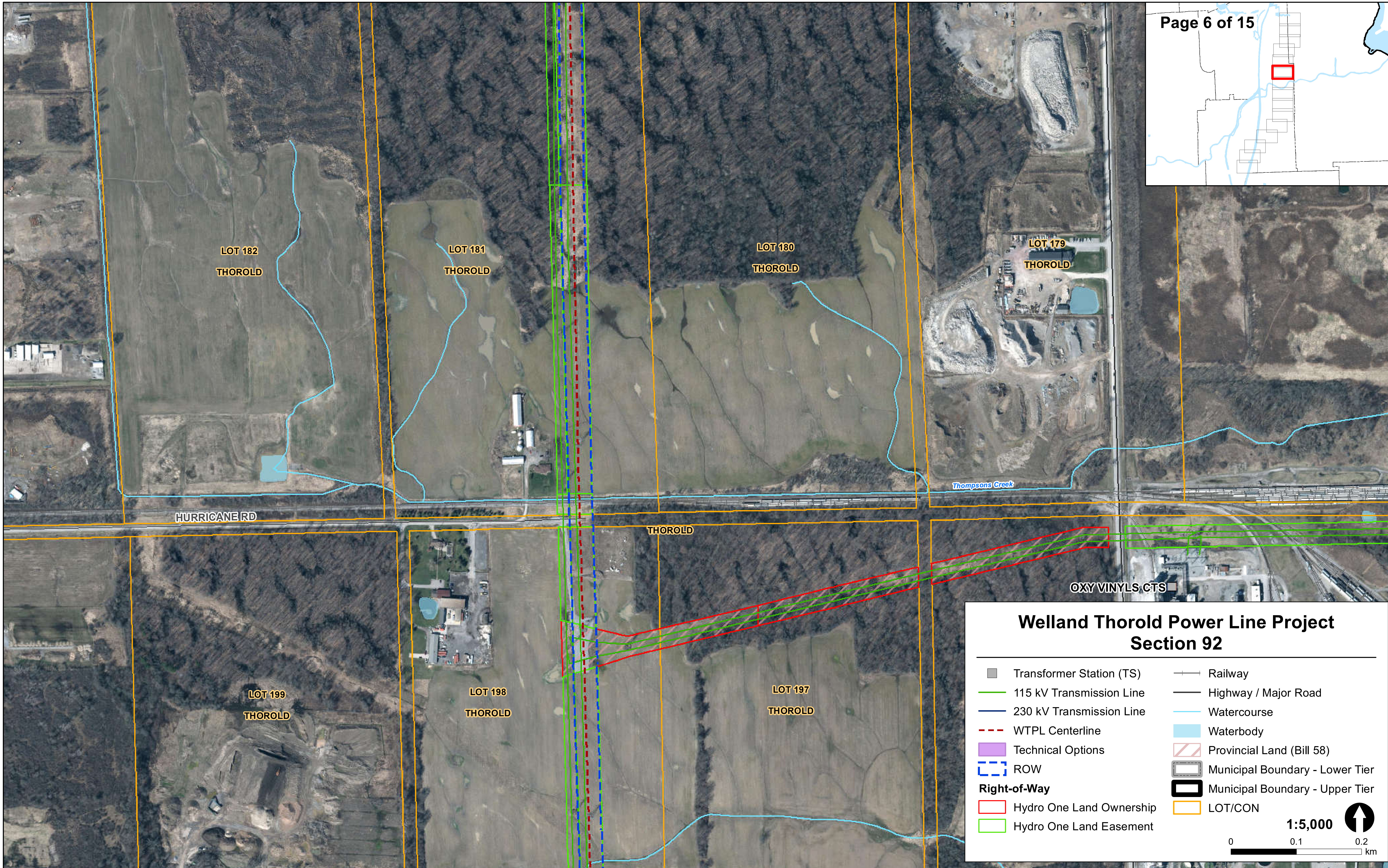

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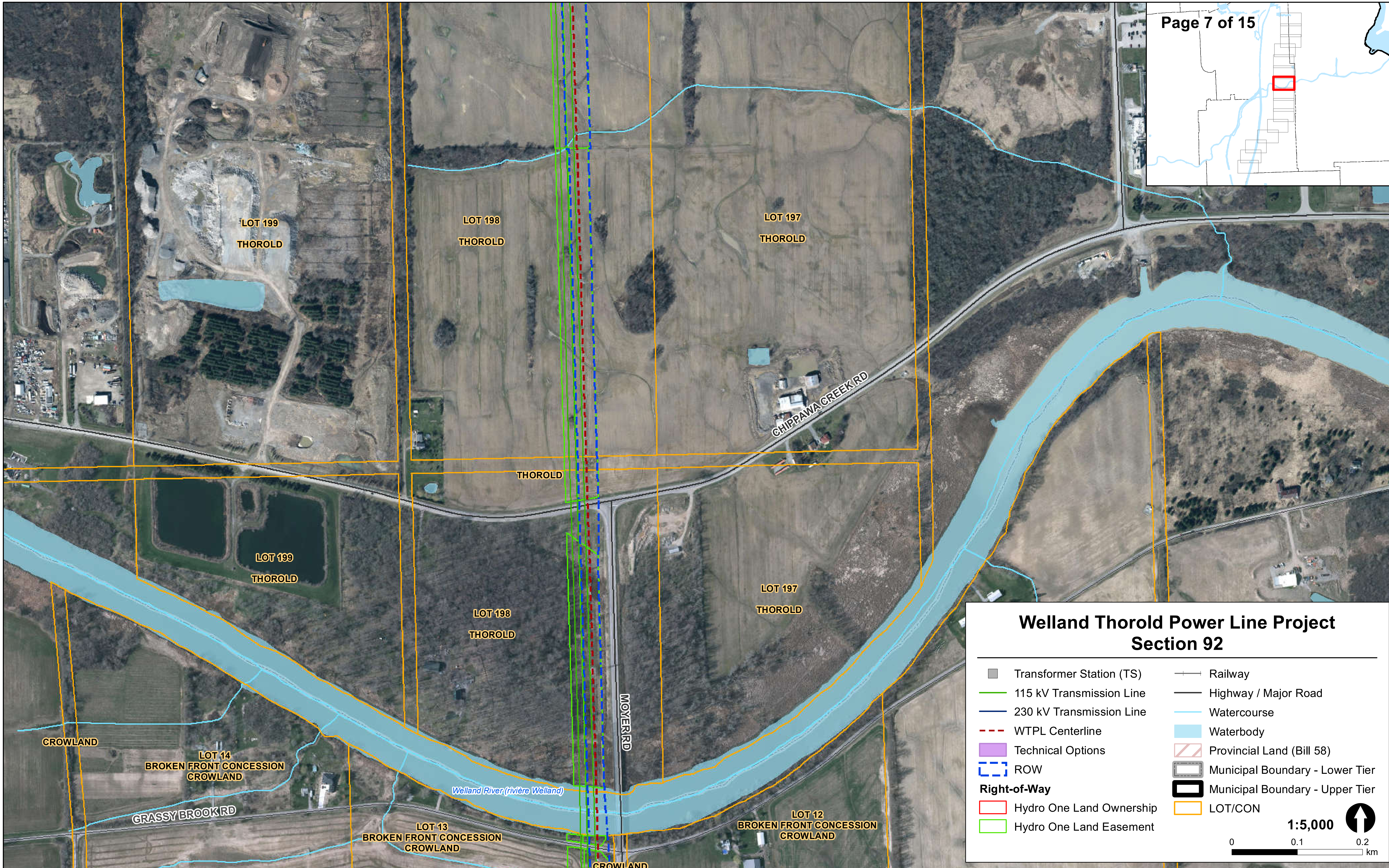

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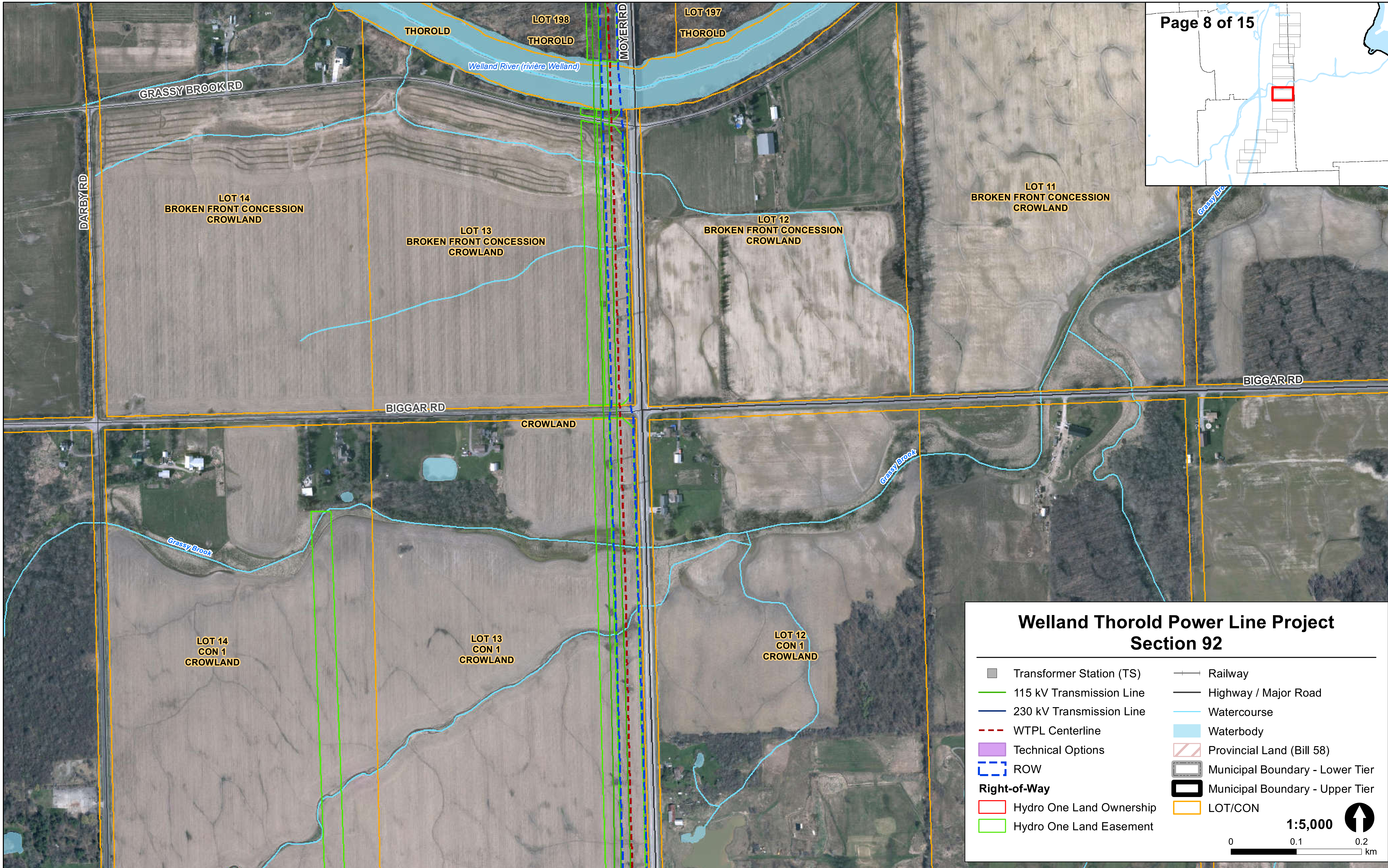

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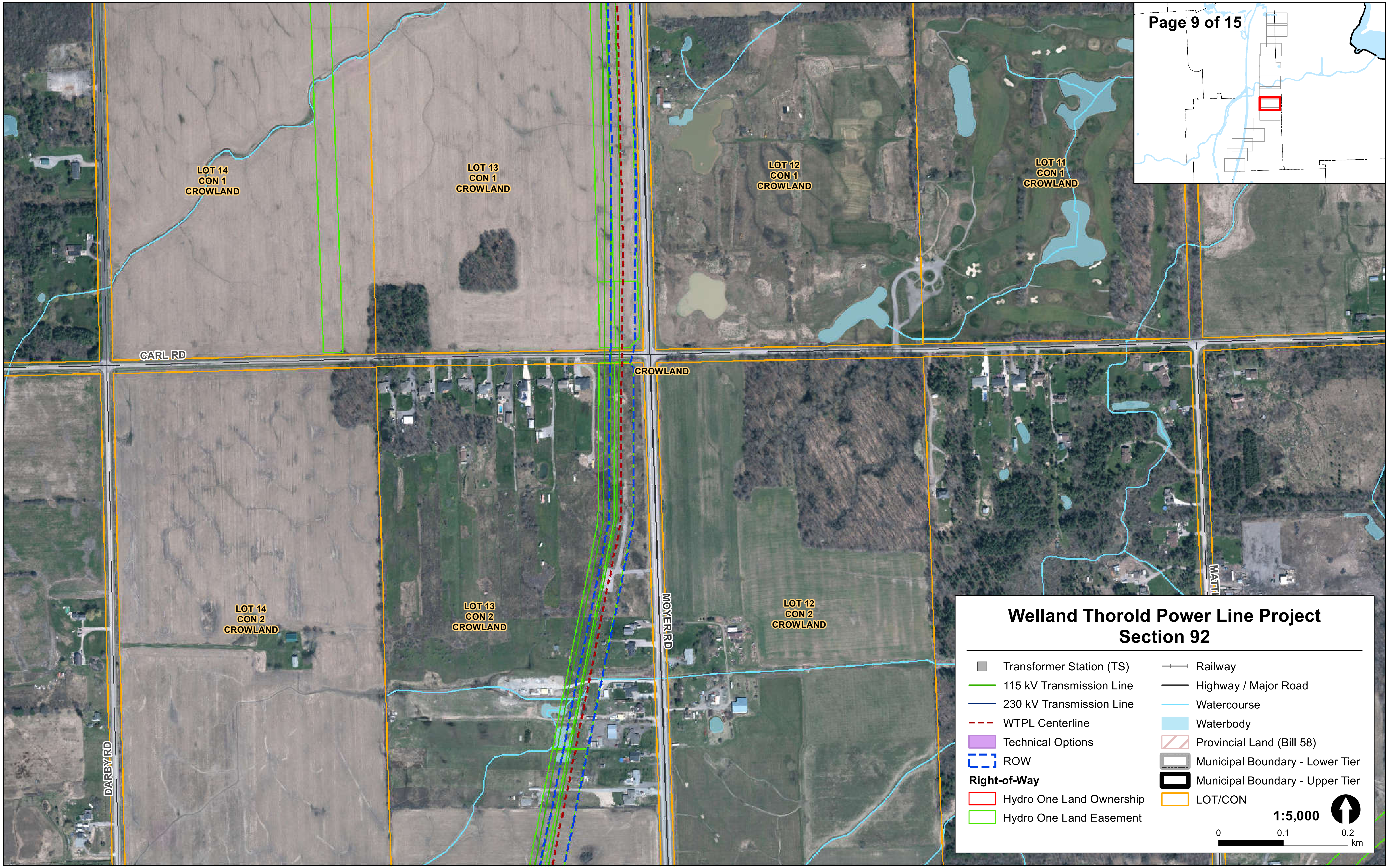

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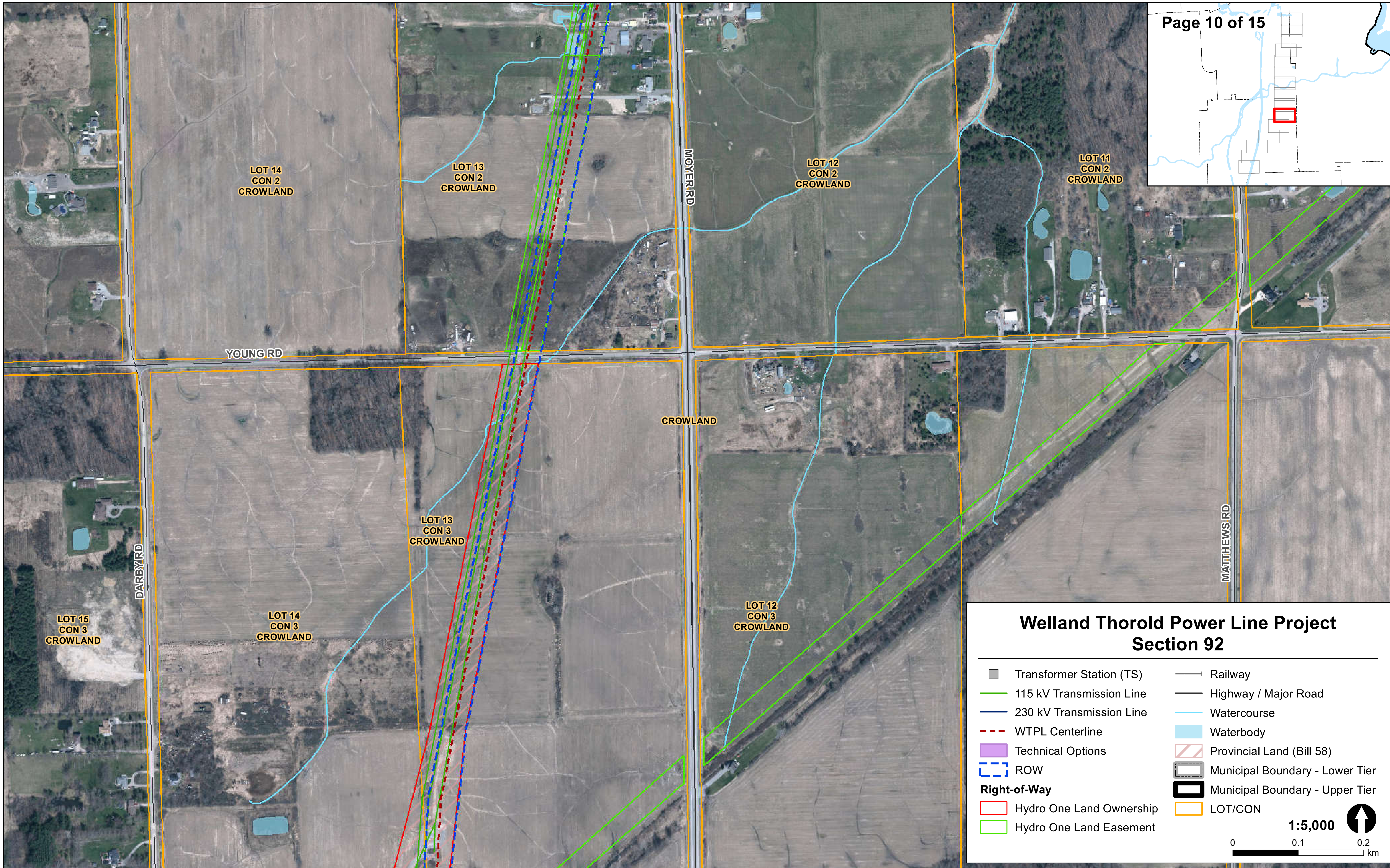

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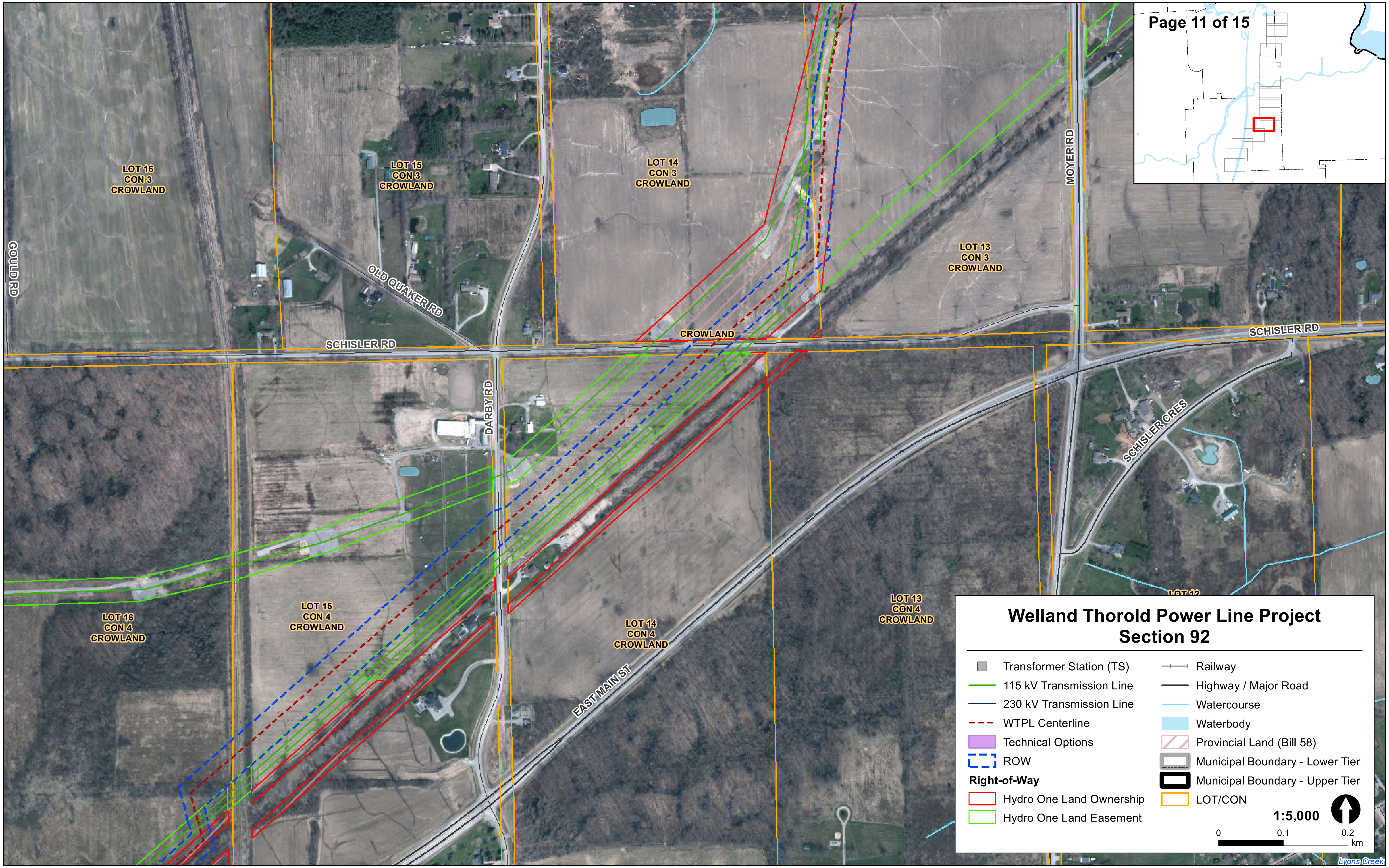

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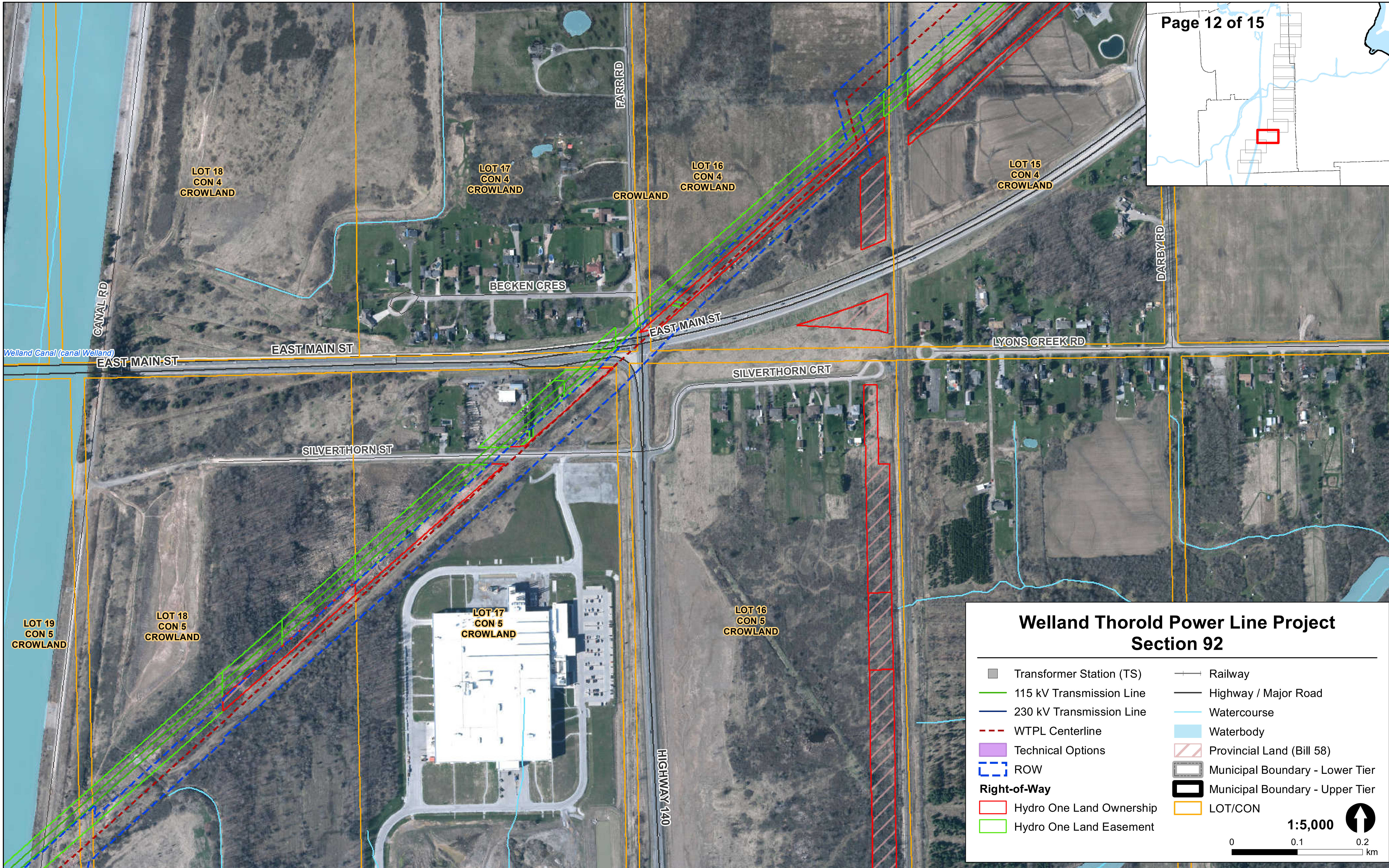

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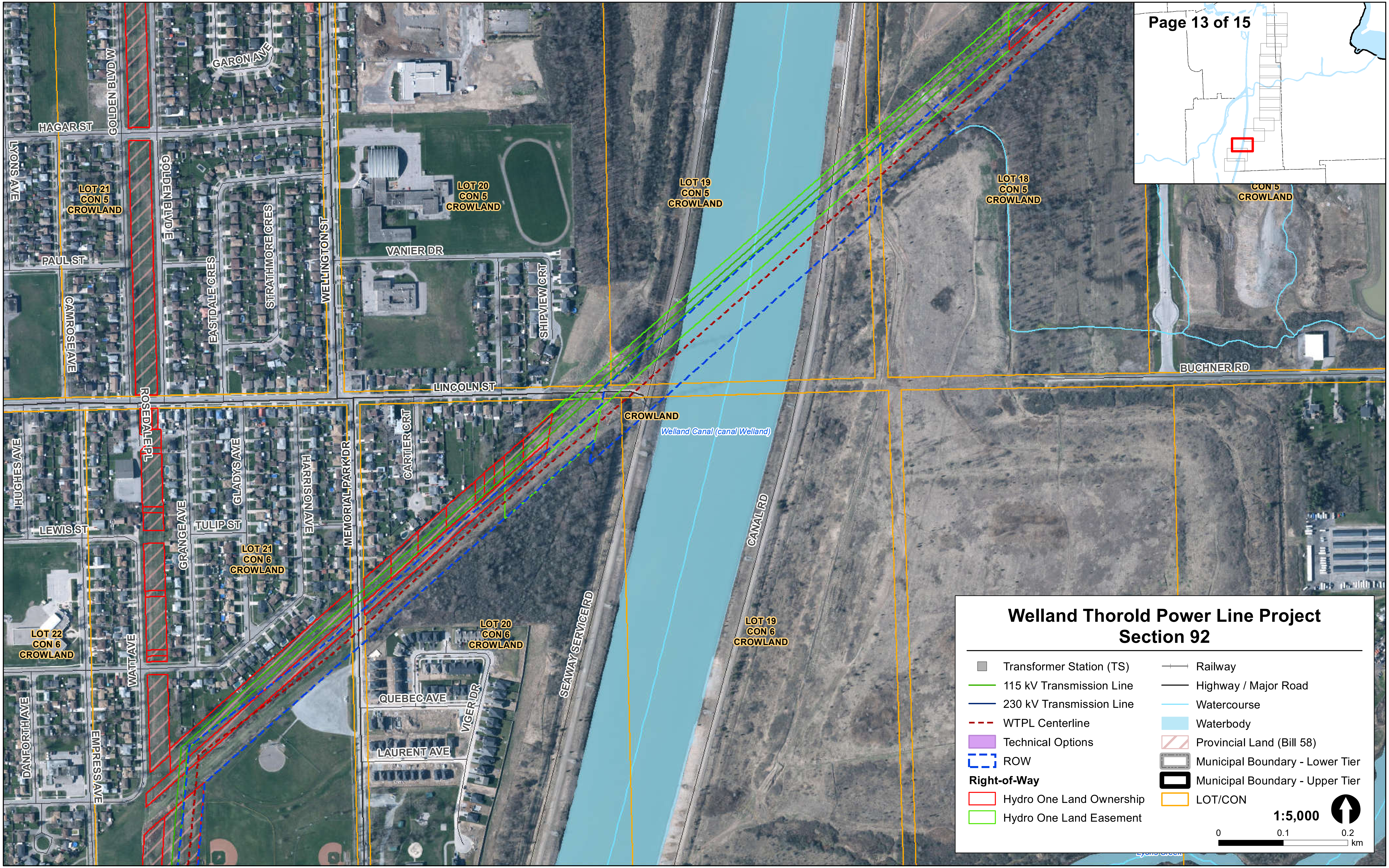

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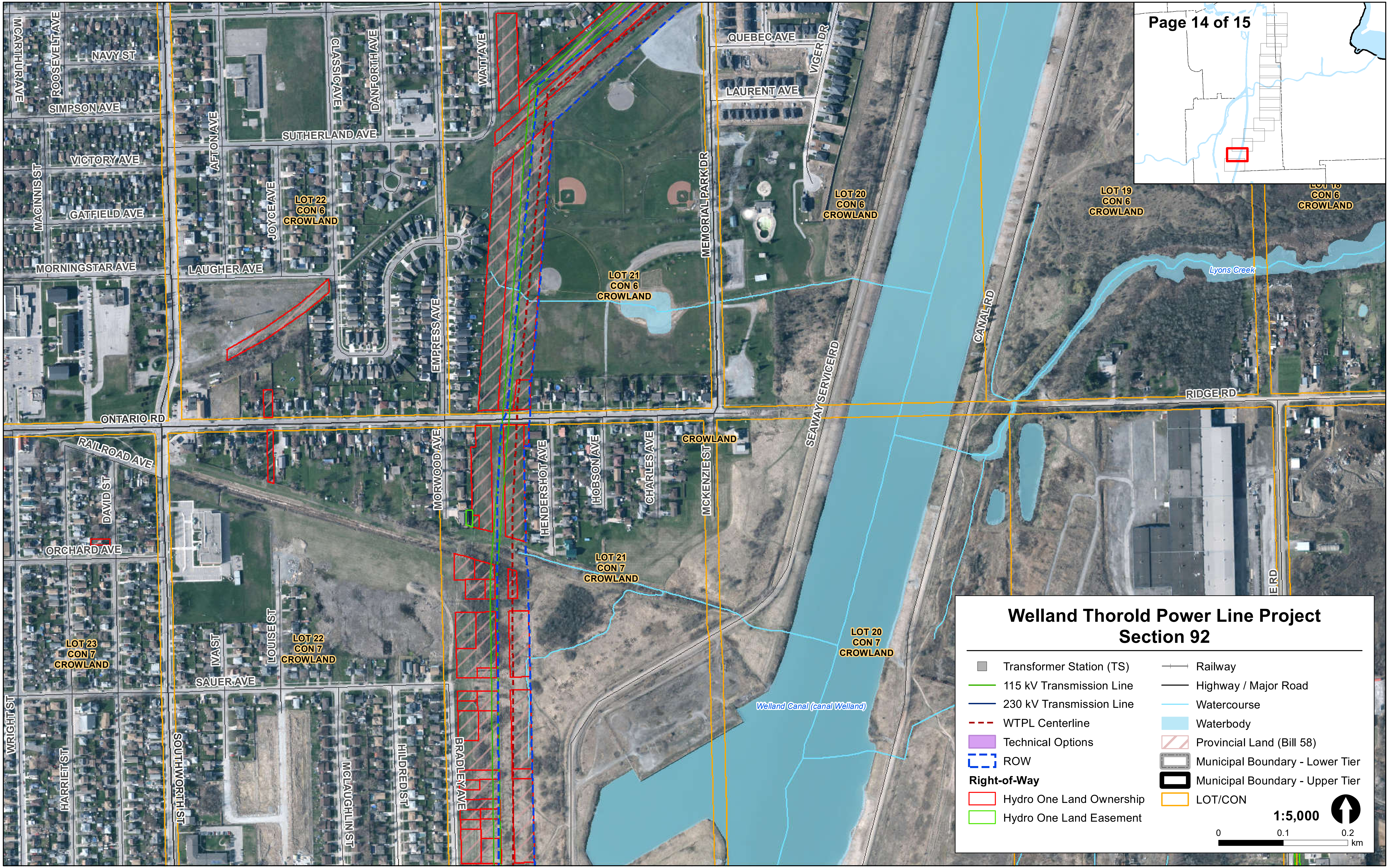

hydro one

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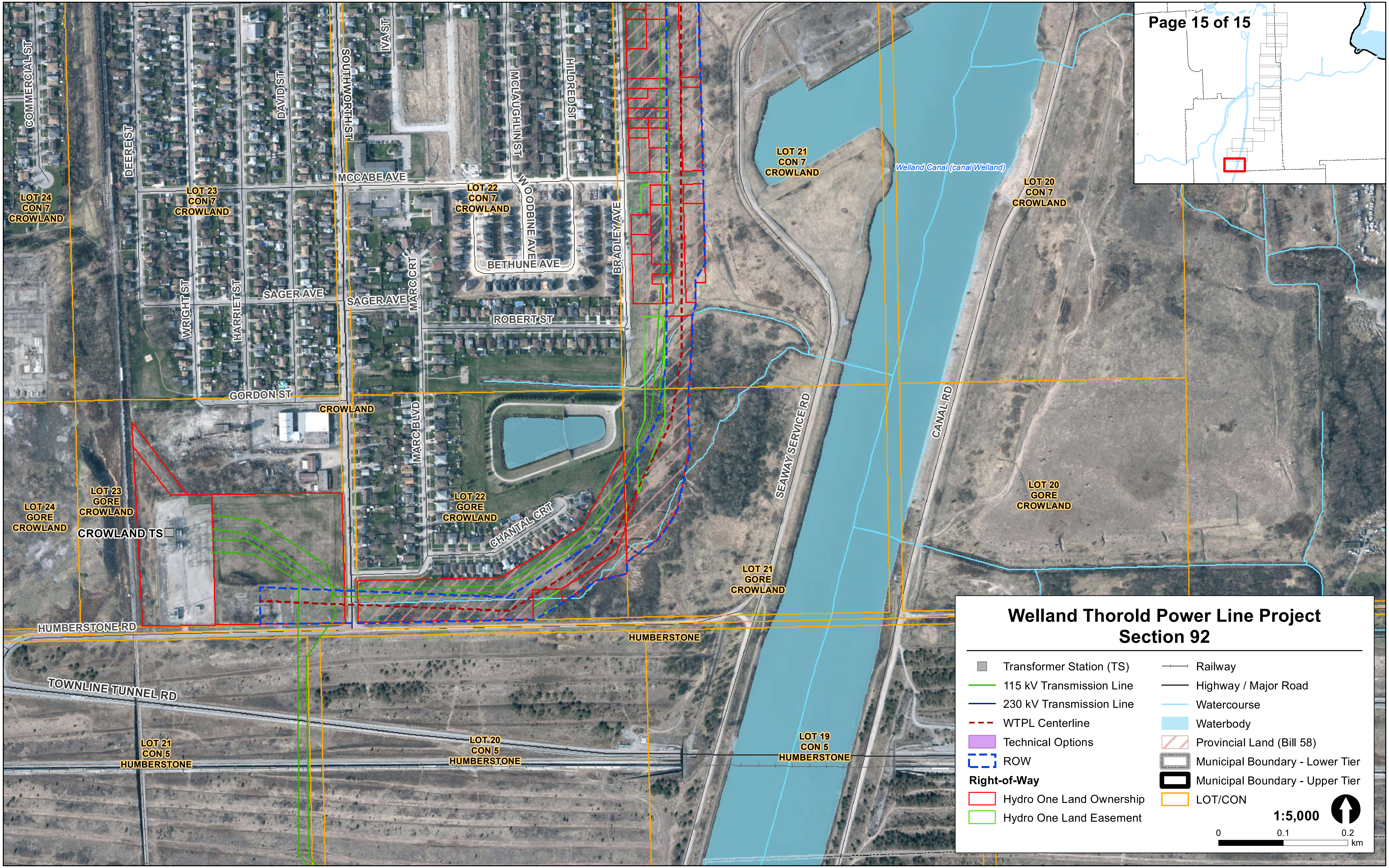

hydro one

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Date: Oct 16, 2025
Map25-046_WTPL_Section92_Tile

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
LAND RIGHTS ACQUISITIONS							
A01	640570086	PT TWP LT 43 THOROLD PT 1, 59R10929; THOROLD	Private	Yes	Permanent Easement	[redacted]	Part of 43 - Page 1 of 15
A02	640570076	PT RDAL BTN TWP LTS 43 & 66 THOROLD BEING PT 3 ON 59R10929 ; S/T INTEREST OF MUNICIPALITY ; THOROL	Private	Yes	Permanent Easement	[redacted]	Part of 43 and Part of Lot 66 - - Page 1 of 15
A03	640570077	PT TWP LT 66 THOROLD BEING PTS 4, 5, 6 & 7 ON 59R10929 ; S/T EASE OVER PT 6 ON 59R10929 AS IN RO149691 ; THOROLD	Private	Yes	Permanent Easement	[redacted]	Part of Lot 66 - Page 1 of 15
A04	640570045	PT TWP LT 66 THLD, AS IN RO670738 ; THOROLD	Private	Yes	Permanent Easement	[redacted]	Part of Lot 66 - Page 1 of 15
A05	640570046	PT TWP LT 66 THLD, AS IN RO209972 ; THOROLD	Private	Yes	Permanent Easement	[redacted]	Part of Lot 66 - Page 1 & 2 of 15
A06	640570088	PT TWP LT 89, THLD, BEING PT 2 ON 59R13776 ; THOROLD	Private	Yes	Permanent Easement	[redacted]	Part of Lot 89 - Page 2 of 15
A07	642650029	PT TWP LT 137 STAMFORD; PT TWP LT 152 STAMFORD AS IN RO155305 (2NDLY) ; NIAGARA FALLS	Private	Yes	Permanent Easement	[redacted]	Part of Lot 137 - Page 2 & 3 of 15
A08	642650030	PT TWP LT 152 STAMFORD PT 1, 59R9592 ; NIAGARA FALLS	Private	Yes	Permanent Easement	[redacted]	Part 152 - Page 2 & 3 of 15
A09	642640002	PT TWP LT 152 STAMFORD; PT TWP LT 153 STAMFORD AS IN RO123266; S/T DEBTS IN RO123266; S/T BENEFICIARIES INTEREST IN RO108807 ; NIAGARA FALLS	Private	Yes	Permanent Easement	[redacted]	Part 152 - Page 3 of 15
A10	642640003	PT TWP LT 152 STAMFORD; PT TWP LT 153 STAMFORD AS IN ST816, ST817 & ST818 LYING BTN THOROLD TOWNLINE RD & NICHOLS LANE ; NIAGARA FALLS	Railway	Yes	Crossing Permit	[redacted]	Part 152 - Page 3 of 15
A11	642640053	PT TWP LTS 152 & 153 STAMFORD AS IN RO197989 ; NIAGARA FALLS...2000-01-05 BY N.P.	Private	Yes	Permanent Easement	[redacted]	Part 152 & 153 - Page 3 of 15
A12	640580069	PT TWP LT 112 THOROLD AS IN RO297086 (SECONDLY) ; THOROLD	Private	Yes	Permanent Easement	[redacted]	Part 112 - Page 3 of 15
A13	640580070	PT TWP LT 112 THOROLD AS IN RO689590 ; THOROLD	Private	Yes	Permanent Easement	[redacted]	Part 112 - Page 4 of 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
B01	640580072	PT RDAL BTN TWP LTS 113 & 114 THOROLD PTS 2, 3 & 4 59R3377 & AS IN RO297086 (FIRSTLY); PT TWP LTS 112 & 113 THOROLD AS IN RO297086 (FIRSTLY) ; DESCRIPTION MAY NOT BE ACCEPTABLE IN FUTURE AS IN RO297086 ; S/T RO366239,TH22487,TH6096 THOROLD	Private	Yes	Permanent Easement	[redacted]	Part 113 & 114 - Page 4 of 15
B02	640580057	PT TWP LT 137 THOROLD AS IN RO385368 ; S/T TH14824, TH21534 THOROLD	Private	Yes	Permanent Easement		Part 137 - Page 4 of 15
B03	640580058	PT TWP LT 137 THOROLD AS IN RO536094 ; S/T TH14824, TH21534 THOROLD	Private	Yes	Permanent Easement		Part 137 - Page 4 & 5 of 15
B04	640580136	PT TWP PT LT 181, THLD, AS IN RO729520 , S/T RO729520 ; THOROLD	Private	Yes	Permanent Easement		Part 181 - Page 5 & 6 of 15
B05	640580138	PT TWP LT 181, THLD, AS IN RO729769 ; S/T TH21315 THOROLD	Private	Yes	Permanent Easement		Part 181 - Page 6 of 15
B06	640580139	PT TWP LT 181, THLD, AS IN AA23100 ; S/T TH21535 THOROLD	Private	Yes	Permanent Easement		Part 181 - Page 6 of 15
B07	640580107	PT RDAL BTN TWP LT 179 & 180 THOROLD, PT RDAL BTN TWP LT 181 & 182 THOROLD, PT TWP LTS 179, 180, 181, 182 & 183 THOROLD, AS IN TH17153 (FIRSTLY) LYING E OF ALLANPORT RD (AKA REGIONAL RD #82), S/T RO510283, RO612373, RO612374 & RO612375 ; S/T TH22635, RO395066, RO663585 CITY OF THOROLD	Railway	Yes	Permanent Easement		Part 179 & 180 - Page 5 & 6 of 15
B08	640580140	PT TWP LTS 197 & 198, THLD, PTS 1, 2, 3, 4, 5, 6, 7, 8, 9, 10 & 11 59R4268 EXCEPT PT 1 59R4743; S/T RO427227 ; S/T AA67756,RO651128 THOROLD	Private	Yes	Permanent Easement		Part 197 & 198 - Page 6 & 7 of 15
B09	640580144	PT TWP LTS 197 & 198, THLD; PT TWP LTS BROKEN FRONT 197 & BROKEN FRONT 198, THLD; PT RDAL BTN TWP LTS 198 & BROKEN FRONT 198, THLD; PT RDAL BTN TWP LTS 197 & BROKEN FRONT 197, THLD, ALL BEING PTS 7-11 & PTS 14-34 59R8603 , EXCEPT PTS 1 & 2 59R9960 ; S/T AA27693, AA88849,RO648012,RO663586,RO669483,RO82212,TH16063, TH21603 THOROLD	Private	Yes	Permanent Easement		Part 197 & 198 - Page 6 & 7 of 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
B10	644290200	PT TWP LT BROKEN FRONT 198 THOROLD , PART 1 & 2 , 59R10085 ; S/T TH21618 THOROLD	Private	Yes	Permanent Easement	[redacted]	Part 198 - Page 7 of 15
B11	644290180	WELLAND RIVER BETWEEN MOYER RD & THE E LIMIT OF THE WELLAND CANAL; EXCEPT, 59R862, 59R9154, PL M10, THE WELLAND RIVER WEST OF PT 26, 59R862, THE WELLAND RIVER AS IN RO319486 & THE WELLAND RIVER BTN THE WELLAND CANAL & THE WLY LIMIT OF RO319486 ; THOROL	Provincial	Yes	Land Use Permit		River - Page 7 & 8 of 15
B12	644290282	1STLY: PART LOTS 13 AND 14, CONCESSION BROKEN FRONT CROWLAND, PARTS 4 TO 11 PLAN 59R16311, SUBJECT TO AN EASEMENT AS IN CR18459; SUBJECT TO AN EASEMENT OVER PARTS 5 AND 7 PLAN 59R16311 AS IN CR17968; SUBJECT TO AN EASEMENT OVER PARTS 9 AND 10 PLAN 59R16311 AS IN RO99816; SUBJECT TO AN EASEMENT OVER PARTS 10 AND 11 PLAN 59R16311 AS IN CR22330; 2NDLY PART LOT 14 CONCESSION BROKEN FRONT CROWLAND, PARTS 1 TO 3 PLAN 59R16311; SUBJECT TO AN EASEMENT AS IN CR18459; SUBJECT TO AN EASEMENT OVER PART 2 PLAN 59R16311 AS IN CR17968; CITY OF WELLAND	Private	Yes	Permanent Easement		Part 13 & 14 - Page 7 & 8 of 15
B13	644290189	PT LTS 13 & 14, CON Broken Front Crowland , AS IN RO114368 ; S/T CR18549,CR22330,RO99816 S/T EASEMENT IN FAVOUR OF THE CONSUMERS' GAS C OMPANY LTD. OVER PT 1 59R11580 AS IN LT200425 ; WELLAND	Private	Yes	Permanent Easement		Part 13 & 14 - Page 7 & 8 of 15
B14	644310022	PT LTS 13 & 14 CON 1 CLD, PT 1 59R633 ; S/T BB77883, CR18506,CR21286,CR32004,CR32124 WELLAND	Private	Yes	Permanent Easement		Part 13 & 14 - Page 7 & 8 of 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
B15	644310025	PT LTS 13 & 14 CON 1 Crowland AS IN RO666940 (FIRSTLY) ; S/T AA72358 ; S/T BB77883,CR18506, CR21286,CR32004,CR32124 ; WELLAND ; SUBJECT TO EXECUTION 96-01582, IF ENFORCEABLE. ; SUBJECT TO EXECUTION 96-01583, IF ENFORCEABLE. ;	Private	Yes	Permanent Easement	[redacted]	Part 13 & 14 - Page 8 of 15
B16	644310052	PT LT 13, CON 2 CROWLAND ; WELLAND	Municipal	Yes	Permanent Easement	[redacted]	Part 13 - Page 8 & 9 of 15
B17	644310051	PT LT 13, CON 2 CROWLAND , PART 11 & 40 , 59R7332 ; S/T DEBTS IN RO597342 ; S/T CR23043,CR31920 WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 13 - Page 8 & 9 & 10 of 15
B18	644310053	PT LT 13, CON 2 CROWLAND , PART 12, 37 & 38 , 59R7332 ; S/T CR23043,CR31920 CITY OF WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 13 - Page 8 & 9 & 10 of 15
B19	644310054	PT LT 13 CON 2 CROWLAND PT 13, 35 & 36, 59R7332; S/T CR23043, CR31920; WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 13 - Page 8 & 9 & 10 of 15
B20	644310055	PT LT 13, CON 2 CROWLAND , PART 14, 33 & 34 , 59R7332 ; S/T CR23043,CR31920 CITY OF WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 13 - Page 8 & 9 & 10 of 15
B21	644310056	PT LT 13, CON 2 CROWLAND ; WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 13 - Page 8 & 9 & 10 of 15
B22	644310057	PT LT 13, CON 2 CROWLAND , PART 16, 29 & 30 , 59R7332 ; S/T CR23043,CR31920 WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 13 - Page 8 & 9 & 10 of 15
B23	644310058	PT LT 13, CON 2 CROWLAND , PART 17, 27 & 28 , 59R7332 ; S/T CR23043,CR31920 WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 13 - Page 8 & 9 & 10 of 15
B24	644310059	PT LT 13, CON 2 CRLD, PART 18, 25 & 26, 59R7332 ; S/T CR23043, CR31920 ; WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 13 - Page 8 & 9 & 10 of 15
B25	644310060	PT LT 13, CON 2 Crowland , PART 19, 23 & 24 , 59R7332 ; S/T CR23043,CR31920 WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 13 - Page 8 & 9 & 10 of 15
B26	644310061	PT LT 13, CON 2 CROWLAND, PARTS 20, 21 & 22 PLAN 59R7332 CITY OF WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 13 - Page 8 & 9 & 10 of 15
B27	644310038	PT LT 13 CON 2 CROWLAND AS IN RO756467; S/T CR29605, CR32125; WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 13 - Page 8 & 9 & 10 of 15
B28	644320040	PT LT 13, CON 3 Crowland , AS IN RO424566 (SECONDLY); T/W RO424566 ; S/T CR18046 WELLAN	Private	Yes	Permanent Easement	[redacted]	Part 13 - Page 9 & 10 & 11 of 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
C01	644320027	PT LT 14 CON 4 CROWLAND AS IN BB24465 EXCEPT BB91990 ; S/T & T/W BB24465 ; S/T CR17947,CR18459, CR22601,CR33098 WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 14 - Page 11 of 15
C02	644320053	PT LT 15 CON 4 CROWLAND AS IN BB24465 & RO107277 LYING N OF 59R753 EXCEPT PTS 48, 50, 52 & 53, 59R935; S/T & T/W BB24465 ; S/T CR22601 ; S/T EASEMENT IN GROSS OVER PTS 1 & 2 59R12854 AS IN SN94995; WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 15 - Page 11 & 12 of 15
C03	644320001	PT LTS 15 & 16 CON 4 CROWLAND , PTS 44, 46, 48, 50 & 52 59R935 S/T RO259243 ; S/T RO388174 ; S/T CR17935,CR22331,CR22601,CR33098 WELLAND	Railway	Yes	Crossing Permit	[redacted]	Part 15 & 16 - Page 11 & 12 of 15
C04	644280464	PT LT 16 CON 4 CROWLAND AS IN RO750264 & PT 45, 47, 49 & 51 59R935; S/T CR17935, CR22331, CR33045; WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 16 - Page 12 of 15
C05	644280466	PT LT 16 CON 4 CROWLAND PT 10 59R753; S/T INTEREST IN RO718612; S/T CR26081; WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 16 - Page 12 of 15
C06	644280513	PT LTS 6, 7, 8 & 216 PL 950 AS IN RO100167; LT 25-39, 83-95 PL 954; PT COLLEGE ST, VICTORIA ST PL 954; PT LT 23-24, 81-82, 40-43, 96-99 PL 954; PT RDAL BTN CON 4 AND CON 5 CROWLAND; PT LT 16 CON 4 CROWLAND; PT RDAL BTN LOTS 16 AND 17 CON 4 CROWLAND; PT LT 17-18 CON 4 CROWLAND; PT RDAL BTN LOTS 18 AND 19 CON 4 CROWLAND; PT LT 19 CON 4 CROWLAND; PT LT 19, 18, 17 CON 5 CROWLAND; PT RDAL BTN LT 18 & 19 CON 5 CROWLAND; PT LT 1-4, 21-28, 61-68 PL 962; PT FITZROY ST, BRUNSWICK ST PL 962 AS IN RO100167, RO176562, RO121671, PT 1 RO118895, PT 1-4 RD153, PT 1, 3, 5 & 8 RD31, PT 1, 2, 3 & 5 RD85, PT 1-6 RD21 BEING HWY 140 AKA EAST MAIN ST BTN HWY 406 AND FARR RD; S/T CR17992; WELLAND	Provincial	Yes	Crossing Permit	[redacted]	Page 12 of 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
C07	644280313	PT LT 17 CON 5 CROWLAND, PT 2 RO819498; WELLAND	Provincial	Yes	Crossing Permit	[redacted]	Part 17 - Page 12 of 15
C08	641280170	PT RDAL BTN LTS 16 & 17, CON 5 CROWLAND, PT 1 SN106361; WELLAND	Provincial	Yes	Crossing Permit		Part 16 & 17 - Page 12 of 15
n/a	641280002	THE KING'S HWY 140 (FMLY MOORE RD) LYING BTN E MAIN ST & RIDGE RD (FMLY ONTARIO RD) ; PT LT 16, CON 4 CROWLAND , PT LT 16, CON 5 CROWLAND , PT RDAL BTN CONS 4 & 5 CROWLAND , PT RDAL BTN LOTS 16 & 17, CON 5 CROWLAND , PT 2 ON RO140489 EXCEPT PT 7 ON RO198852 ; PT RDAL BTN LOTS 16 & 17, CON 5 CROWLAND , PT 2 ON RO224191 ; PT RDAL BTN LOTS 16 & 17, CON 5 CROWLAND , PT RDAL BTN LOTS 16 & 17, CON 6 CROWLAND , (CLOSED BY ORDER IN COUNCIL RO224191) PT 1 & 2 ON RO119798 ; PT LTS 16 & 17, CON 5 CROWLAND , PT LT 16 & 17, CON 6 CROWLAND , PT RDAL BTN CONS 5 & 6 CROWLAND , PT RDAL BTN CONS 6 & 7 CROWLAND , PT OF PT 1 ON RO109442 LYING BTN E MAIN ST & RIDGE RD (FMLY ONTARIO RD) ; PT LT 16, CON 5 CROWLAND , PART 1 , 59R1753 , EXCEPT PT 7 ON RO198852 ; PT LT 16, CON 5 CROWLAND , PT 1 ON RO125190 ; PT LT 16, CON 5 CROWLAND , PT 1, 2 & 3 ON RO125191 ; PT LT 16, CON 5 CROWLAND , PT 1, 2 & 3 ON RO125192 ; PT LTS 16 & 17, CON 6 CROWLAND , PART 1, 2 & 3 , RD102 ; PT RDAL BTN LOTS 16 & 17, CON 5 CROWLAND , PT 1 ON RO119798 ; PT RDAL BTN LOTS 16 & 17, CON 6 CROWLAND , PT 2 ON RO119798 ; S/T DEBTS IN RO126407 ; S/T BENEFICIARIES INTEREST(S) IN	Provincial	Yes	Crossing Permit		Page 12 of 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
n/a	641280146	PT LT 16, CON 5 CROWLAND BEING PART 2 ON 59R12788 ; WELLAND	Provincial	Yes	Crossing Permit	[redacted]	Part 16 - Page 12 of 15
C09	644110217	PT LT 17 CON 5 CROWLAND PTS 1-4 59R383 ; S/T CR18085,CR33139; T/W RO314765; WELLAND	Private	Yes	Permanent Easement		Part 17 - Page 12 of 15
C10	644110218	PT LT 17 CON 5 CROWLAND PT 12 59R753 & PT 1 RD132 ; S/T CR33139, S/T RO353938 ; WELLAND	Private	Yes	Permanent Easement		Part 17 - Page 12 of 15
C11	644110216	PT LT 17 CON 5 CROWLAND AS IN RO148620 ; S/T CR33139 ; WELLAND ;	Private	Yes	Permanent Easement		Part 17 - Page 12 of 15
C12	644110220	PT LT 17 CON 5 CROWLAND PT 1 59R292, PTS 1 & 2 RD222 & PTS 1, 8 & 9 RD20; S/T RO366554 ; S/T CR33139 SUBJECT TO AN EASEMENT IN FAVOUR OF PART LOT 17 CONCESSION 5 CROWLAND PART 1 59R4787 EXCEPT PARTS 1, 3 & 4 59R9133 AS IN SN494877 SUBJECT TO AN EASEMENT IN FAVOUR OF PART LOT 17 CONCESSION 5 CROWLAND PART 1 59R9133 AS IN SN494877 SUBJECT TO AN EASEMENT IN FAVOUR OF PART LOT 17 CONCESSION 5 CROWLAND PART 4 59R9133 AS IN SN494877 SUBJECT TO AN EASEMENT IN FAVOUR OF PART LOT 17 CONCESSION 5 CROWLAND PART 1 59R2229 EXCEPT PART 1 59R4787 AS IN SN494877 CITY OF WELLAND	Municipal	Yes	Permanent Easement		Part 17 - Page 12 of 15
C13	644110293	PT LTS 17 & 18 CON 5 TWP CLD ; PT 13, 59R753 ; WELLAN	Municipal	Yes	Permanent Easement		Part 17 & 18 - Page 12 & 13 of 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
C14	644110322	LTS 213 TO 215, 217 TO 218, 225 TO 238, 329 TO 338, 403 TO 413, 417, 443 TO 457,583, LAWRENCE AV, BIRMINGHAM ST, SHEFFIELD AV, DOMINION ST,WHITNEY ST,(CLOSED BY BYLAW AA23015), FRONT ST.(CLOSED BY BYLAW AA23015 & BB90236) PL 947 EXCEPT PART 1 59R12467; LTS 219 TO 224, 339 TO 402, 458 TO 582, 584 TO 733, EUCLID AVE. (CLOSED BY BYLAW AA23015 &BB90236) PL 947; LTS 1 TO 378, BRUNSWICK ST, DELDA AV, FITZROY ST, LINTON AV, MCDONALD AV, REEL AV (ALL CLOSED BY BYLAW BB90236) PL 962 EXCEPT RO100167; PT ELIZABETH ST (NKA DIMARTLE, CLOSED BY BYLAW BB90236) PL 953; PT LT 19 CON 5 CLD PT 17 59R753 & AS IN BB37309; PART LOTS 17 & 18, CON 5 CLD, PARTS 13 & 16 59R753 & BB37309; PT LT 19 CON 6 CLD, PT 18 59R753 & AS IN BB37309; PT RDAL BTN CONS 6 & 7 CLD (CLOSED BY BYLAW RO109259) AS IN BB37309; RD AL BTN LTS 18 & 19 CON 5 CLD EXCEPT RO100167; PT LT 20 CON 6 CLD PTS 14 & 18 59R753 & AS IN BB37309; PT LT 20 CON 6 CLD AS IN BB50310, BB51504 & BB61434; PT RDAL BTN CONS 5 & 6 CLD (AKA LINCOLN ST & REGIONAL RD 29) AS IN BB37309; WELLAND (A REVISED DESCRIPTION WILL BE REQUIRED IN THE FUTURE)	Federal	Yes	Crossing Permit	[redacted]	Page 13 of 15
C15	644110306	PT LT 20 CON 6, TOWNSHIP OF CROWLAND, BEING PT 14 ON 59R753 ; WELLAND	Private	Yes	Permanent Easement	[redacted]	Part 20 - Page 13 of 15
C16	641190574	PT LT 21, CON 6, Crowland , PT 15, 59R753 LYING E OF 59R8834 ; WELLAND	Municipal	Yes	Permanent Easement	[redacted]	Part 21 - Page 13 & 14 of 15
C17	641190575	PT LT 21, CON 6 CLD, PTS 1 & 2, BB53723 ; WELLAN	Municipal	Yes	Permanent Easement	[redacted]	Part 21 - Page 13 & 14 of 15
C18	641270504	PT LT 21 & 22 CON CROWLAND, AS IN CR272, CR304; WELLAN	Private	Yes	Permanent Easement	[redacted]	Part 21 - Page 14 of 15
C19	641270276	PT LT 21 & GORE CON 7 CROWLAND AS IN CR17047 (AMENDED BY CR18465)(FMLY LTS 569 TO 596, PL 970) ; S/T RO66358 WELLAND	Municipal	Yes	Permanent Easement	[redacted]	Part 21 - Page 14 of 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
C20	641270509	LT 230, PL 970 ; WELLAND	Municipal	Yes	Permanent Easement	[redacted]	Page 14 & 15
C21	641270530	LTS 1 TO 329, MACKENZIE DR., JEFFERY RD., LAMONT RD., BEST AVE., EVELYN ST (AS CLOSED BY BYLAW BB90236) PL 956 EXCEPT RO164895; LTS 104- 106, 141 TO 157, 192 TO 214, 228, 229, 260 TO 262, 264 TO 417, 504 TO 557, RICHARDSON AVE., SIDNEY AVE., SWAYZE ST., ROYCE AVE., SHEFFIELD AVE., PT CAROLINE AVE., PT SAUER AVE., PT MCCABE AVE., PT GLADE AVE., PT LYONS BLVD., PT HOBSON AVE., PT CHARLES AVE., PT EVELYN ST. (AS CLOSED BY BYLAW BB90236), PL 970 EXCEPT BB75643, RO745854, RO689583, RO747087; LTS 1 TO 23, NINA ST., VIDA ST., CHAMBERS ST., (FORMERLY LAWRENCE AVE.) (AS CLOSED BY BYLAW BB90236)PL 958; LTS 3 - 12, ENRICO ST., PT UDINE AVE (AS CLOSED BY BB90236), PL 971; LYONS CREEK RD., PL 961 (AS CLOSED BY BYLAW BB90236); PT LT 19 & GORE, 20 & GORE, PT LT 21 & GORE, PT LT 22 & GORE, CON 7 CLD, PT RDAL BTN LTS 20 & 21 CON 7 CLD (AS CLOSED BY BYLAW BB90236); PT LTS 17 TO 21, CON 5 HUMBERSTONE; PT RDAL BTN LTS 18 & 19 CON 5 HUMBERSTONE (AS CLOSED BY BYLAW RO102483 & RO185603); PT RDAL BTN LTS 20 & 21, CON 5 HUMBERSTONE (AS CLOSED BY BYLAW BB90236); PT RDAL BTN TWP	Federal	Yes	Permanent Easement	[redacted]	Page 14 & 15
C22	641270500	PT LT 22 & GORE, CON 7 Crowland , AS IN BB98456 & RO104704 EXCEPT PART 1 RO714112 ; S/T CR21093,RO87968 WELLAN	Federal	Yes	Permanent Easement	[redacted]	Page 14 & 15
NO/LIMITED RIGHTS REQUIRED							
	644290192	GRASSY BROOK RD (FMLY CREEK RD) BTN MOYER RD & PT 1, 59R8745 , BEING A FORCED RD THROUGH PT LTS 13, 14 & 15, CON Broken Front , Crowland ; THOROL	Road Allowance	No	Rely on S.41(1) of the Electricity Act	[redacted]	Page 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
	644290193	BIGGAR RD BTN MOYER RD (AKA REGIONAL RD NO. 84) & THE WELLAND CANAL ; PT RDAL BTN CON 1 & CON BF, LYING BTN MOYER RD & RO185456 ; PT LTS 16, 17 & 18, CON 1 Crowland , AS IN RO185456 ; PT RDAL BTN CON 1 & CON BF, CLD, AS IN RO185456 ; PT RDAL BTN LTS 16 & 17, CON 1 CLD, AS IN RO185456 ; WELLAND	Road Allowance	No	Rely on S.41(1) of the Electricity Act	[redacted]	Page 15
	642610001	RDAL BTN LT 12 & 13 CON 2 CROWLAND; RDAL BTN LT 12 & 13 CON 3 CROWLAND; PT RDAL BTN CON 2 & 3 CROWLAND; PT LT 12 CON 2 CROWLAND AS IN BB84595; PT LT 13 CON 2 CROWLAND AS IN BB82485, BB82484 & BB84599; PT LT 12 CON 3 CROWLAND AS IN BB82486 & PT 4, 59R753; PT LT 13 CON 3 CROWLAND AS IN BB84642 & PT 5 59R753; BEING MOYER RD (AKA REG RD 84), LYING BTN EAST MAIN ST & CARL RD ; WELLAND	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	644110136	MEMORIAL PARK DR (AKA REGIONAL RD 62) BEING RDAL BTN LTS 20 & 21 CON 6 Crowland ; WELLAND	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	641270508	PT HUMBERSTONE RD (AKA REGIONAL RD. 33) LYING E OF SOUTHWORTH ST., EXC EPT BB37309 BEING PT RDAL BTN TWP OF CROWLAND AND HUMBERSTONE ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	641270197	GLASGOW AV, PL 970 , (FORMERLY GOLDEN AV) PARTS 1 & 2 59R9292 ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	640580017	BARRON RD BTN ALLANPORT RD & TOWNLINE RD, RDAL BTN TWP LTS 116 & 139 THLD; RDAL BTN TWP LTS 115 & 138 THLD; RDAL BTN TWP LTS 114 & 137 THLD; RDAL BTN TWP LTS 113 & 136 THLD; RDAL BTN TWP LTS 112 & 135 Thorold ; THOROL	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
	640580155	CHIPPAWA CREEK RD (AKA RIVER RD, COUNTY RD #19 & REGIONAL RD #63) , LYING BTN ALLANPORT RD & STAMFORD TOWNLINE RD, BEING A FORCED RD THROUGH PT TWP LTS 199, 200, Broken Front 199, Broken Front 198, Broken Front 197, 197, 196 & PT RDAL BTN LT 199 & Broken Front 199 & LT 197 & Broken Front 197, Thorold AS IN RO114158 LYING E OF THE SLY PRODUCTION OF THE WLY LIMIT OF PT 1 59R1312, PT 2 59R6407 & RO745826 (THIRDLY, FOURTHLY LYING W OF THE SLY PRODUCTION OF THE E LIMIT OF AA11709, SEVENTHLY, EIGHTHLY, NINTHLY, TENTHLY, ELEVENTHLY, TWELTHLY, THIRTEENTHLY, FOURTEENTHLY & FIFTEENTHLY) ; THOROLD	Road Allowance	No	Rely on S.41(1) of the Electricity Act	[redacted]	Page 15
	642640001	RDAL BTN TWP OF THOROLD & TWP OF STAMFORD LYING BTN LUNDYS LANE & MCLEOD RD ALL BEING THOROLD TOWNLINE RD (AKA REGIONAL RD 70) ; NIAGARA FALLS/THOROLD	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	641190598	ONTARIO RD (AKA REGIONAL RD 31) BEING RDAL BTN CONS 6 & 7 CROWLAND ; ONTARIO ROAD, PL 976 , (AKA WIDENING) ; PT LT 22, CON 7 CROWLAND , PT 1, 59R6338 ; 'PT LT 22, CON 6 CROWLAND, PT 1, 59R7742' ; WELLAND (AMENDED 99-FEB-26 BY AM BERTRAND)	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	644280534	PT LT 16 CON 4 CROWLAND; PT RDAL BTN CON 4 AND CON 5 CROWLAND PT 19, 20, 21 & 22 59R394 EXCEPT PT 4, 30R11506; BEING EAST MAIN ST BTN FARR RD AND 59R935; WELLAND	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	644310026	CARL RD, LYING BTN THE WLY LIMIT OF PT 14, 59R862 & MOYER RD, BEING; PT RDAL BTN CON 1 & 2 Crowland ; PT LTS 13 & 14 CON 1 Crowland AS IN AA70265 ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
	644280463	PT RDAL BTN LOTS 16 AND 17 CON 4 CROWLAND; PT LT 16 CON 4 CROWLAND AS IN RO198852 & AA59161 BEING FARR RD BTN SCHISLER RD AND EAST MAIN ST; WELLAND	Road Allowance	No	Rely on S.41(1) of the Electricity Act	[redacted]	Page 15
	641270270	MCCABE AV, PL 970 , EXCEPT BB90236 ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	644080075	PT HUMBERSTONE RD. (AKA REGIONAL RD. 33) LYING BTN THE CANADIAN RAILWAY LANDS AND SOUTHWORTH ST; BEING PT RDAL BTN TWP OF CROWLAND AND HUMBERSTONE ; WELLAND	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	641270266	SAUER AV, PL 970 , EXCEPT BB90236 ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	641270275	GLADE AV, PL 970 , EXCEPT BB90236 ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	641270264	PT REILLY AV, PL 970 , (FORMERLY GOLDEN AV) LYING BTN CAROLINE AV (FORMERLY ORCHARD AV) & SAUER AV ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	642620166	RDAL BTN LT 12 & 13 CON Broken Front CROWLAND; RDAL BTN LT 12 & 13 CON 1 CROWLAND; PT LT 12 CON Broken Front CROWLAND; PT LT 13 CON Broken Front CROWLAND; PT LT 12 CON 1 CROWLAND; PT LT 13 CON 1 CROWLAND AS IN RO748309, ALL BEING MOYER RD, LYING BTN THE WELLAND RIVER & CARL RD ; S/T CR20752,CR21286,CR22330 NIAGARA FALLS	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	641270459	EVELYN ST, PL 970 , EXCEPT BB90236 ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	641270001	SOUTHWORTH ST (AKA REG RD 60 & 68) LYING BTN ONTARIO RD & HWY 406 BEING RDAL BTN LT 22 & GORE & 23 & GORE CON 7 CROWLAND ; PT LT 22 & GORE, CON 7 CROWLAND , PART 8 , 59R1145 , PT LT 22 & GORE, CON 7 CROWLAND , PART 2 , 59R6338 ; PT LT 22 & GORE, CON 7 CROWLAND , PT LT 545, PL 946 , PART 8 , 59R2478 ; PT LTS 83, 84, 85, 86, 87, 88, 89, 90 & 91, PL 946 , PART 1 , 59R5879 ; WELLAND	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
	644310040	YOUNG RD (FMLY CAMBRIDGE RD), LYING BTN WLY LIMIT OF PT 8 PL 59R862 & MOYER RD, BEING; PT RDAL BTN CONS 2 & 3 Crowland ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act	[redacted]	Page 15
	640580059	POLLOWAY RD, RDAL BTN TWP LT 136 & 137 Thorold ; THOROL	Road Allowance	No	Rely on S.41(1) of the Electricity Act	[redacted]	Page 15
	640570020	UPPERS Lane (AKA UPPER LANE) BEING; PT RDAL BTN TWP LTS 70 & 93 THLD, RDAL BTN TWP LTS 69 & 92 THLD, RDAL BTN TWP LTS 68 & 91 THLD, RDAL BTN TWP LTS 67 & 90 Thorold & RDAL BTN TWP LTS 66 & 89 THLD, LYING BTN THE KING'S HWY # 58 & TOWN LINE RD ; THOROL	Road Allowance	No	Rely on S.41(1) of the Electricity Act	[redacted]	Page 15
	644320026	DARBY RD , LYING BTN SCHISLER RD (FMLY OXFORD RD) & E MAIN ST , BEING; PT LT 15 CON 4 CLD, PT RDAL BTN LTS 14 & 15 CON 4 CLD, ALL BEING PT 2, RO198852 ; PT RDAL BTN LOTS 14 & 15, CON 4 Crowland ; S/T CR26080 WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act	[redacted]	Page 15
	640580108	HURRICANE RD , LYING BTN ALLANPORT RD & STAMFORD TOWNLINE RD , BEING ; RDAL BTN TWP LT 179 & 196 Thorold , RDAL BTN TWP LT 180 & 197 Thorold , RDAL BTN TWP LT 181 & 198 Thorold , RDAL BTN TWP LT 182 & 199 Thorold , RDAL BTN TWP LT 183 & 200 Thorold ; THOROLD	Road Allowance	No	Rely on S.41(1) of the Electricity Act	[redacted]	Page 15
	642650084	CONSOLIDATION OF VARIOUS PROPERTIES PT TWP LT 134 STAMFORD; PT TWP LT 137 STAMFORD; PT RDAL BTN TWP LT 137 & 138 STAMFORD; PT TWP LT 138 STAMFORD; PT RDAL BTN TWP LT 138 & 139 STAMFORD; PT TWP LT 139 STAMFORD; PT TWP LT 152 STAMFORD; PT TWP LT 153 STAMFORD AS IN AA96852& RO607148; BEING LUNDYS LANE (AKA KING'S HWY #20 & NIAGARA RD 51) FORMERLY CANBORO RD) LYING BTN THOROLD TOWN LINE RD & KALAR RD; NIAGARA FALLS	Road Allowance	No	Rely on S.41(1) of the Electricity Act	[redacted]	Page 15
	644110219	SILVERTHORNE ST BEING; PT LTS 17 & 18 CON 5 Crowland AS IN RO198852 (PTS 9 & 10) ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act	[redacted]	Page 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
	642650001	PT RDAL BTN TWP OF STAMFORD & THOROLD; PT TWP LT 152 STAMFORD PT 2, 59R9592 & AS IN AA96852; BEING THOROLD TOWNLINE RD (AKA THOROLD TOWN LINE RD & REGIONAL RD 70) LYING BTN BEAVERDAMS RD & LUNDYS Lane ; NIAGARA FALL	Road Allowance	No	Rely on S.41(1) of the Electricity Act	[redacted]	Page 15
	641270261	CAROLINE AV, PL 970 , (FORMERLY ORCHARD AV), EXCEPT BB90236 ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	640580093	TURNER RD BTN ALLENPORT RD & TOWNLINE RD, RDAL BTN TWP LTS 139 & 183 THLD; RDAL BTN TWP LTS 138 & 182 THLD; RDAL BTN TWP LTS 137 & 181 THLD; RDAL BTN TWP LTS 136 & 180 THLD; RDAL BTN TWP LTS 135 & 179 Thorold ; THOROL	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	641270187	BRADLEY AV, PL 970 , (FORMERLY EMPRESS AV) ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	641270260	PT REILLY AV, PL 970 , (FORMERLY GOLDEN AV) LYING N OF CAROLINE AV (FORMERLY ORCHARD AV) ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	644320019	SCHISLER RD (FMLY OXFORD RD), LYING BTN THE CNR & MOYER RD, BEING ; PT RDAL BTN CONS 3 & 4 Crowland , EXCEPT PT 2, RO187686 ; PT LT 13, CON 3 Crowland , PART 1 , RD93 ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	641270273	PT REILLY AV, PL 970 , (FORMERLY GOLDEN AV) LYING BTN MCCABE AV AND GLADE AV ; WELLAN	Road Allowance	No	Rely on S.41(1) of the Electricity Act		Page 15
	641270268	PT REILLY AV, PL 970 , (FORMERLY GOLDEN AV), LYING BTN SAUER AV & MCCABE AV ; WELLAN	Bill 58/Owned	No	Rely on S.41(1) of the Electricity Act		Page 15
	642620001	PT TWP LT 198 Broken Front THOROLD BEING MOYER RD (AKA REGIONAL RD 84), A GIVEN RD THROUGH ; NIAGARA FALL	Bill 58/Owned	No	Rely on S.41(1) of the Electricity Act		Page 15
	640580192	PT TWP LT 114 THOROLD BEING PT 1 ON 59R12706 ; THOROLD	Bill 58/Owned	No	Owned by Hydro One		Page 15
	641270456	PT LT 22 & GORE CON 7 CLD, AS IN AA9549, AA62792, CR32656 ; PT LT 21 & GORE, CON 7 CROWLAND , AS IN AA9549, AA10951; S/T RO166194; WELLAND (AMENDED JUNE 25, 1999, A. ROBLEY	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
	640580143	PT TWP LTS 197 & 198, THLD, AS IN BB41309, BB43049 & BB41310; S/T RO113288 ; THOROL	Bill 58/Owned	No	Rights in Place (Bill 58)	[redacted]	Page 15
	640580195	PT TWP LTS 112 & 113 THOROLD PTS 1 & 2 59R3205; PT RDAL TWP LTS 113 & 114 THOROLD PT 3 59R3205; S/T INTEREST OF THE MUNICIPALITY; THOROLD	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15
	641270267	LTS 418, 419, 420, 421, 422, 423, 424, 425, 426, 427, 428, 429, 430, 431, 432, 433 & 434, PL 970, S/T RO166194; WELLAND (AMENDED JUNE 25, 1 999, A. ROBLEY	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15
	640570002	PT TWP LTS 43, 44 & 67 Thorold , AS IN TH17683, EXCEPT PTS 1, 2, 3 59R6514, LYING E OF HWY 58 AS SHOWN ON BB73017 & S BEAVER DAMS RD ; PT RDAL BTN TWP LT 44 & 45 Thorold , AS IN TH17683, LYING S HWY 58, AS SHOWN ON BB73017 ; RDAL BTN TWP LT 44 & 67 Thorold , EXCEPT PT 1, 59R6514 ; PT TWP LT 43 Thorold , AS IN TH17360, TH21123 ; PT TWP LT 45 Thorold , AS IN TH17371, LYING SE OF HWY 58, N RDAL BTN TWP LTS 45 & 68 Thorold & W RDAL BTN TWP LTS 44 & 45 Thorold ; PT RDAL BTN TWP LT 67 & 68 Thorold , AS IN TH17683, LYING N PTS 1 & 4, 59R6514 ; PT TWP LT 68 Thorold , AS IN TH21125, LYING E THE KINGS HWY # 58 (AS SHOWN ON BB73017) ; PT RDAL BTN TWP LT 45 & 68 Thorold , (CLOSED BY BL122) LYING E OF THE KING"S HIGHWAY # 58 ; S/T INTEREST OF MUNICIPALITY ; S/T RO298735 ; THOROLD (AMENDED ON 2000/07/18 AT 15:14 BY M.SEVERY)	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15
	644110208	PT LT 17 CON 5 AS IN CR3671 LYING N OF SILVERTHORNE ST ; S/T RO176244 ; S/T EASEMENT AS IN RO314765; WELLAND	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15
	644110305	PT LT 20 CON 6 CROWLAND AS IN CR3713, BB23180, BB27824, RO142499,RO142500, RO142502, RO142504 & RO153271; WELLAND	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
	642650023	PT TWP LT 136 STAMFORD; PT TWP LT 137 STAMFORD AS IN ST53431, ST53581 & RO68350; S/T ST53581; S/T ST53431 ; NIAGARA FALL	Bill 58/Owned	No	Rights in Place (Bill 58)	[redacted]	Page 15
	640570041	PT TWP LT 89 THOROLD , TH22995 & TH22334, S/T TH22995 ; PT RDAL BTN TWP LT 90 & 91 THOROLD , PT TWP LT 90 THOROLD , AS IN TH22330, S/T TH22330; S/T EASEMENT OVER PT 9 ON 59R13352 AS IN RO727581 ; THOROLD	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15
	641270198	LTS 36, 37, 38, 39, 40, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 54, 55, 56, 57 & 58, PL 970 ; WELLAN	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15
	641190576	LT 8, PL 976 ; PT LT 21, CON 6, CROWLAND, AS IN CR20943 & CR32474 ; S/T RO166194 WELLAN	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15
	644080074	PT LT 23 & GORE CON 7 CROWLAND AS IN AA15185, CR21171, CR21053 ; S/T RO353835 WELLAND (AMENDED DESC. JUNE 29, 1999, A. ROBLEY)	Bill 58/Owned	No	Owned by Hydro One		Page 15
	644110566	PART LOT 20 CONCESSION 6 CROWLAND BEING PARTS 1, 2 & 3 ON PLAN 59R16672 SUBJECT TO AN EASEMENT IN GROSS OVER PART 2 ON PLAN 59R16672 AS IN SN577726 CITY OF WELLAND	Bill 58/Owned	No	Rights in Place (Instrument SN577726)		Page 15
	640580052	PT TWP LTS 137 & 138 Thorold AS IN TH5203 & TH5169 ; THOROL	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15
	641270265	LTS 253, 255, 256, 257, 258 & 259, PL 970, S/T RO166194 (AMENDED JUNE 25, 1999, A. ROBLEY) ; WELLAN	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15
	644320039	PT LTS 13 & 14 CON 3 Crowland AS IN CR3666; PT LTS 13 & 14 Crowland AS IN CR31939 ; S/T CR31939; S/T & T/W CR3666 ; DESCRIPTION MAY NOT BE ACCEPTABLE IN FUTURE AS IN CR3666 ; S/T EASEMENT IN FAVOUR OF ENBRI DGE GAS DISTRIBUTION INC. OVER PT 1, 59R11427 AS IN LT227397 ; WELLAND	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15
	641190261	BLK A, PL 635 ; WELLAN	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15
	644280465	PT LT 16 CON 4 CROWLAND AS IN CR3663 BTN EAST MAIN ST AND PT 44 59R935; WELLAND	Bill 58/Owned	No	Rights in Place (Bill 58)		Page 15

File	PIN	LEGAL DESCRIPTION	TYPE OF PROPERTY	RIGHTS REQUIRED (YES OR NO)	RIGHTS REQUIRED	OWNER 1	Map Reference -
	641270274	LTS 493, 494, 495, 496, 497, 498, 499, 500, 501, 502 & 503, PL 970 , EXCEPT PART 1 RO714112 ; S/T RO166194 WELLAN	Bill 58/Owned	No	Rights in Place (Bill 58)	[redacted]	Page 15
	641190440	PT LT 21, CON 6, Crowland , AS IN CR3726 & CR3734 LYING E OF 59R7479; T/W RO647918 ; WELLAN	Bill 58/Owned	No	Rights in Place (Bill 58)	[redacted]	Page 15
	641270257	LT 231, PL 970 , EXCEPT PART 1 RO714112 ; WELLAN	Bill 58/Owned	No	Rights in Place (Bill 58)	[redacted]	Page 15
	644110207	PT LT 18 CON 5 Crowland AS IN CR3671, CR3641 & CR3673 LYING S OF SILVERTHORNE ST ; WELLAN	Bill 58/Owned	No	Rights in Place (Bill 58)	[redacted]	Page 15

THIS AGREEMENT made in duplicate the _________day of _______________202__

Between:

INSERT NAME

(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 LEGAL DESCRIPTION] as in PIN XXXXX-XXXX (LT), (the "Lands").

WHEREAS HONI in connection with the Welland Thorold Power Line Project (the "Project") desires the right to enter onto a portion of the Lands in order to carry out all necessary real estate, environmental and engineering studies and testing including but not limited to borehole testing, archaeological studies, soil assessments, property appraisals and surveys on, over and upon the Lands associated with the Project.

WHEREAS the Grantor is agreeable in allowing HONI to enter onto a portion of the Lands for the purpose of all necessary studies and testing on, over and upon the Lands, subject to the terms and conditions contained herein.

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the sum of TWO DOLLARS ($2.00) now 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 green as shown in Schedule "A" attached hereto (the "Preferred Route"), 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 Preferred Route for the purpose of real estate, environment and engineering studies and testing associated with the Project, subject to payment of compensation for damages including payment for crop land out of production caused thereby;

(b) to cut and remove all trees, brush and other obstructions made necessary by the exercise of the rights granted hereunder with prior consent of the Grantor, subject to payment of compensation for damages.

2. The term of this Agreement and the permission granted herein shall be two (2) years (the "Initial Term") commencing in accordance with the option selected by the Grantor below:

(i) The Initial Term commences on the Agreement date written above.

☐ Grantor Initials for Option 2(i):_________________________

(ii) The Initial Term commences on September 1, 2025 or earlier as agreed upon between HONI and Grantor.

☐ Grantor Initials for Option 2(ii):________________________

3. Upon execution of this Agreement by all parties, HONI shall pay to the Grantor the amount of FIVE THOUSAND DOLLARS ($5,000.00), which is compensation for the permission granted herein for the Initial Term.

4. HONI may, in its sole discretion, and upon 5 days prior written notice to the Grantor, extend the Initial Term for an additional term of one (1) year on the same terms and conditions contained herein save for this right to extend and section 3 herein (the "Extended Term").

5. In the event that HONI exercises its right to extend the Initial Term, HONI shall pay to the Grantor the amount of TWO THOUSAND FIVE HUNDRED DOLLARS ($2,500.00), which is compensation for the permission granted herein for the Extended Term.

6. Upon the expiry of the Term or any extension thereof, HONI shall repair any physical damage to the Preferred Route and/or Lands resulting from HONI's use of the Preferred Route and the permission granted herein; and, shall restore the Preferred Route to its original condition so far as possible and practicable.

7. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Preferred Route 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.

8. 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 Preferred Route or of its activities on or in connection with the Preferred Route 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.

9. 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 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 7S3

Attention: Real Estate Acquisitions
Tel: 905-875-2508
Fax: 905-878-8356

TO GRANTOR:

Name:
Address:

Attention:
Tel:

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 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.

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. 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.

12. The burden and benefit of this Agreement shall run with the Lands and everything herein contained shall operate to the benefit of, and be binding upon, the respective heirs; successors, permitted assigns and other legal representatives, as the case may be, or each of the Parties hereto.

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.

SIGNED, SEALED AND DELIVERED
In the presence of)
)
)
)
)
______________________________________) ______________________________________
(seal)
Print Name of Witness [INSERT NAME]

[INSERT FULL LEGAL NAME]

Per:
____
Name:
Title:

Per:
____
Name:
Title:

We/I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

Per:
____
Name: **Aaron Fair**

Title: **Real Estate Services Supervisor**

I have authority to bind the Corporation

<u>SCHEDULE "A"</u>

PROPERTY SKETCH

Conceptual sketch only.

[INSERT PROPERTY MAP]

OPTION AGREEMENT - EASEMENT

THIS OPTION AGREEMENT made as of the __________ day of _________________, 20___ (the "**Agreement Date**").

B E T W E E N:

JOHN SMITH

(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 **XX ($XX)** 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 **XX ($XX)** 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:	**OWNER:**
	l/s
Name:	Name: ***John Smith***
Address:	
	l/s
Name:	Name:
Address:	
	l/s
Name:	Name:
Address:	

WITNESS:

The spouse of the Owner hereby consents to this Agreement

SPOUSE OF OWNER:

	l/s
Name:	Name:
Address:	

JOHN SMITH

Per: ____________________
Name:
Title:

We/I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ____________________
Name: Aaron Fair
Title: Real Estate Services Supervisor

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________________

Name: Thanh Lam

Title: Senior Manager, Transmission Acquisition

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________________

Name: Ranjit Multani

Title: Director, Land Acquisitions and Management

I have authority to bind the Corporation

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 $10,000 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: Real Estate Manager
Fax: (905) 946-6242

with a copy to its solicitors,

Attention:
Fax:

OWNER:

123 Main Street

XXXX, ON

Phone Number: XXX-XXX-XXXX
Email: XXXXXXX

with a copy to their solicitors,

Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5^{th}) 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

XXXXXXXX (the "**Transferor**") is the owner in fee simple and in possession of the certain lands legally described as XXXXXXXXXXXXXXXXXXXXXXXXXXXXXX (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:	Name: **John Smith**
Address:	
_______________________	_______________________ l/s
Name:	Name:
Address:	
_______________________	_______________________ l/s
Name:	Name:
Address:	

WITNESS:	The spouse of the Owner hereby consents to this Acknowledgement and Direction
	SPOUSE OF OWNER:
	l/s
Name:	Name: **Property Owner Spouse Name**

JOHN SMITH

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:

JOHN SMITH

(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 XXXXXXX 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 ($XX)** 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 50% 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: Real Estate Manager
Fax: (905) 946-6242

with a copy to its solicitors,

Attention:
Fax:

OWNER:

123 Main Street
XXXX, ON

Phone Number: XXXXXXXXXX
Email: XXXXXXXXXXXXX

with a copy to their solicitors,

Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5^{th}) 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.

(THE REMAINDER OF THIS PAGE IS INTENTIONALLY LEFT BLANK)

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

WITNESS:	**OWNER:**
	l/s
Name:	Name: **John Smith**
Address:	
	l/s
Name:	Name:
Address:	
	l/s
Name:	Name:
Address:	

WITNESS:

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

SPOUSE OF OWNER:

l/s

Name:

Address:

Name:

Per:

Name:

Title:

We/I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per:

Name: Aaron Fair

Title: Real Estate Services Supervisor

I have authority to bind the Corporation

HYDRO ONE
HST 870865821RT0001

HYDRO ONE NETWORKS INC.

Per: ______________________________

Name: Thanh Lam

Title: Senior Manager, Transmission Acquisition

I have authority to bind the Corporation

HYDRO ONE
HST 870865821RT0001

HYDRO ONE NETWORKS INC.

Per: ______________________________

Name: Ranjit Multani

Title: Director, Land Acquisitions and Management

I have authority to bind the Corporation

SCHEDULE "A"

LANDS

(LEGAL DESCRIPTION OF LANDS)

SCHEDULE “B”

CALCULATION SHEET

Insert screenshot of calculation sheet

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.

D. As the Owner's primary residence is located on the Lands within 100 metres from the centreline of the proposed new transmission line to be constructed on the Easement Lands, Hydro One has agreed that if Hydro One exercises the Option it will offer to purchase the Lands up to XXXXXX on the terms and conditions of the Voluntary Buyout Offer (the "Voluntary Buyout Offer") attached as Schedule "E" to this Option Agreement which Voluntary Buyout Offer shall be made on the Closing Date.

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:	**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 Agreement **SPOUSE OF OWNER:**
	l/s
Name: «Real_Estate_Representative»	Name: **Property Owner Spouse Name**
Address: 1800 Main Street East Milton, ON L9T 7S3	

«OWNER_1_NAME_FOR_LETTERS»

Per: ______________________

Name:

Title:

We/I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________

Name: Aaron Fair

Title: Real Estate Services Supervisor

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________________

Name: Thanh Lam

Title: Senior Manager, Transmission Acquisition

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST 870865821RT0001

Per: ______________________________

Name: Ranjit Multani

Title: Director, Land Acquisitions and Management

I have authority to bind the Corporation

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 $10,000 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: Real Estate Manager
Fax: (905) 946-6242

with a copy to its solicitors,

Attention
Fax:

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.

28. **VOLUNTARY BUYOUT OFFER**

a) If Hydro One exercises the Option in accordance with the terms hereof then, on Closing in addition to delivery of a cheque for the Purchase Price, Hydro One shall deliver to the Owner an offer to purchase the Lands on the terms set out in the Voluntary Buyout Offer attached as Schedule “E”.

b) The Purchase Price of the Voluntary Buyout Offer shall be the fair market value of the Lands as determined by a new appraisal commissioned by Hydro One and, prepared by an external, independent appraiser with the Accredited Appraiser Canadian Institute (“AACI”) designation at the time the Owner accepts the offer set out in Schedule “E” of this Option Agreement.

If the Owner does not accept the Voluntary Buyout Offer within the prescribed time specified therein, Hydro One shall not be required to purchase the Owner’s interest in the Lands, and the Voluntary Buyout Offer shall be of no further force or effect and Hydro One shall be released of all obligations in respect thereof.

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»

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

Name: **«Owner_3_name_for_letters»**

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

SCHEDULE "E"
VOLUNTARY BUYOUT OFFER

B E T W E E N:

«OWNER_1_NAME_FOR_LETTERS» & «OWNER_2_NAME_FOR_LETTERS» & «OWNER_3_NAME_FOR_LETTERS»

(hereinafter called the "**Vendor**")

OF THE FIRST PART

- and -

HYDRO ONE NETWORKS INC.

(hereinafter called the "Purchaser")

OF THE SECOND PART

- and -

XXXXXXXX

(hereinafter called the "**Spouse**")

OF THE THIRD PART

RECITALS

A. The Vendor entered into an Option Agreement with the Purchaser dated ● (the "**Option Agreement**") pursuant to which the Vendor granted the Purchaser an option to purchase a right-of-way and easement (the "**Easement**") in, on, over, under, across and through that portion of the Lands described on Schedule "A-1" attached thereto (the "**Easement Lands**"), the terms of which are more particularly set out in the Transfer and Grant of Easement (the "**Easement Agreement**") attached thereto as Schedule "C".

B. The Purchaser entered into an agreement with the Vendor having a date the same as the Option Agreement (the "**Compensation and Incentive Agreement**") whereby the Purchaser offered to compensate the Vendor for injurious affection damages, if applicable.

C. The Purchaser has exercised the Option to acquire the Easement pursuant to the Option Agreement.

D. As the Vendor's primary residence is located on the Lands within 100 metres from the centreline of the proposed new transmission line to be constructed on the Easement Lands, pursuant to the Option Agreement the Purchaser agreed to offer to purchase the Lands on the terms and conditions set out herein.

E. Initially capitalized terms not otherwise defined in this agreement shall have the meaning given to them in the Option Agreement and Compensation and Incentive Agreement.

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

ARTICLE 1
OFFER

1.1 The Purchaser hereby offers to purchase from the Vendor the lands and premises more particularly described in Schedule "A" attached hereto (the "**Lands**") upon and subject to the terms and conditions hereinafter set forth.

1.2 The Vendor acknowledges and understands that upon acceptance of this Offer by the Vendor there shall be a binding Agreement of Purchase and Sale between the Purchaser and the Vendor.

1.3 Included in the Purchase Price is the purchase of all of the Vendor's interest in all fixtures, improvements, and appurtenances located on the Property except those listed below which are expressly excluded:

To be determined

1.4 The parties acknowledge and agree that this offer shall be irrevocable by the Purchaser until 3:30PM on the earlier of:

(a) December 31, 2026; or

(b) the date on which the Vendor ceases to be the registered and beneficial owner of the Lands (the "Irrevocable Date").

If the Vendor has not delivered a copy of this Agreement executed by the Vendor to the Purchaser on or before 3:30PM on the Irrevocable Date, this offer shall be null and void.

ARTICLE 2
PURCHASE PRICE

2.1 The purchase price for the Lands (the "Purchase Price") shall be the fair market value of the Lands as determined, as of the date of acceptance of this offer by the Vendor, by an external, independent AACI accredited appraiser retained by the Purchaser, at its expense, less an amount equal to the aggregate of the following amounts paid by the Purchaser to the Vendor pursuant to the Option Agreement and the Compensation and Incentive Agreement:

(a) the Purchase Price for the Easement (as defined in the Option Agreement) in the amount of XXXXX Dollars ($XXXXX.00);
(b) the IA Compensation, if any, in the amount of XXXXX Dollars ($XXXXX.00);
(c) Other compensation, if any, in the amount of XXXXX Dollars ($XXXXX.00).

2.2 The amount to be paid by the Purchaser to the Vendor on Closing for the Lands shall be the Purchase Price, as adjusted, after deducting the amounts as set out in Section 2.1 hereof, being the minimum amount of SEVEN HUNDRED FOURTY-NINE THOUSAND EIGHT HUNDRED FIFTY DOLLARS ($749,850.00) representing the current fair market value of the land after adjustments. Should the appraised value of the land at the time of acceptance by the Vendor yield a result after adjustments that exceeds the minimum, the Vendor shall be entitled to the excess value. Should the appraised value of the land at the time of acceptance by the Vendor yield a result after adjustments that is less than the minimum, the Vendor shall be entitled to the minimum.

2.3 The Purchaser agrees to obtain and register, at its sole expense, any new Reference Plan with respect to the Lands that may be required by the Purchaser for completion of the transaction contemplated herein.

ARTICLE 3
CLOSING

3.1 The closing of this transaction shall be completed on the day that is ninety (90) days after the Vendor notifies the Purchaser of its intention to accept the Offer. If the Closing falls on a day when the Land Registry Office (the "Land Registry Office") in which the Lands are registered is closed, then the Closing shall be extended to the next day on which the Land Registry Office is open. 3.2 On Closing:

(a) Vacant possession of the Lands shall be given to the Purchaser;

(b) The Purchaser shall pay to the Vendor by uncertified cheque or electronic funds transfer the Purchase Price as adjusted and subject to the deductions made in accordance with section 2.1 of this Agreement;

(c) Rents, realty taxes, local improvement charges, water and unmetered utility charges and the cost of fuel as applicable shall be apportioned and allowed to the date of completion (the day itself to be apportioned to the Purchaser);

(d) 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"), Purchaser shall report and pay to the Receiver General, the Harmonized Sales Tax ("HST") applicable to the purchase and sale of the Property. For the purposes of this clause 3.2(b), the Purchaser 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 Property for use primarily in the course of its commercial activities.

3.3 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.

ARTICLE 4
TITLE

4.1 The Purchaser shall be allowed thirty (30) days from the date of acceptance of this Agreement to investigate title to the Property at its own expense (the "**Title Search Period**"), to satisfy itself that there are no outstanding encumbrances, or liens save and except those listed in Schedule "B" attached hereto (the "Permitted Encumbrances") and until the earlier of: (i) thirty (30) days from the later of the last date of the title search period or the date or which the conditions in this Agreement are fulfilled or otherwise waived or; (ii) five (5) days prior to completion, to satisfy itself that there are no outstanding work orders or deficiency notices affecting the Lands. Vendor hereby consents to the Municipality or other governmental agencies releasing to the Purchaser details of all outstanding work orders affecting the Lands and the Vendor agrees to execute and deliver such further authorizations in this regard as Purchaser may reasonably require.

4.2 Provided that the title to the Lands is good and free from all registered restrictions, charges, liens and encumbrances except the Permitted Encumbrances, if within the Title Search Period, any valid objection to title is made by the Purchaser in writing to the Vendor together with documentary verification thereof, and which the Vendor shall be unwilling or unable to remove and which the Purchaser will not waive, this Agreement, notwithstanding any intermediate acts or negotiations in respect of such objections, shall be at an end and the Vendor shall not be liable for any costs or damages and the Vendor and the Purchaser shall be released from all obligations hereunder, and the Vendor shall also be released from all obligations under this Agreement, save and except those covenants of the Purchaser expressly stated to survive Closing or other termination of this Agreement. Save as to any valid objection to title made in accordance with this Agreement and within the Title Search Period, and except for any objection going to the root of title, Purchaser shall be conclusively deemed to have accepted Vendor's title to the Lands.

4.3 The Vendor agrees to provide to the Purchaser any existing survey of the Lands in the Vendor's possession, within fifteen (15) days from the date of the Vendor's acceptance of the offer.

ARTICLE 5
PURCHASER'S INVESTIGATION RESULTS

5.1 Purchaser shall, at its own cost, forthwith make such investigation as the Purchaser deems appropriate of the Lands and Vendor's title as provided for in this Agreement and shall notify the Vendor of any objection to title, together with a complete copy of any documents and other material information related thereto prior to the expiry of the Title Search Period.

ARTICLE 6
INSURANCE

6.1 The Vendor covenants and agrees that the Lands and all structures or fixtures being purchased are insured, and that such insurance will remain in force until closing. The Lands and all structures or fixtures being purchased shall be and remain at the risk of the Vendor until Closing.

6.2 Pending completion, Vendor shall hold all insurance policies and the proceeds thereof in trust for the parties as their interests may appear and in the event of substantial damage to the Lands the Purchaser will take the proceeds of any insurance and complete the purchase.

ARTICLE 7
PLANNING ACT

7.1 This Agreement is subject to the express condition that it is to be effective only if the subdivision control provisions of the *Planning Act* R.S.O. 1990, c. P.13 as amended (the "*Planning Act*") are complied with by the Vendor prior to Closing. The Vendor shall forthwith make any application to the local Committee of Adjustment or Land Division Committee for any consent that may be required pursuant to the *Planning Act*. In the event that any such application for consent is denied, or any condition imposed by such body is unacceptable to the Vendor, this Agreement shall be terminated.

ARTICLE 8
ADDITIONAL PROVISIONS

8.1 The Transfer/Deed of Land (the "**Transfer**"), and the Land Transfer Tax Affidavit, shall be prepared in registrable form by the Purchaser, and the Purchaser covenants at its cost to register the Transfer on Closing. If requested by Purchaser, Vendor covenants that the Transfer Deed to be delivered on completion shall contain the statements contemplated by s. 50(22) of the *Planning Act*.

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

8.3 Any tender of documents or money hereunder may be made upon the Parties or their respective solicitors on the day set for Closing. Money may be tendered by bank draft, uncertified cheque, or electronic funds transfer.

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

with a copy to its solicitors,

Barriston LLP
90 Mulcaster St
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,

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 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.

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

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

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

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

8.9 The offer to purchase contained herein is personal to the Vendor and shall not be assigned by the Vendor and does not enure to the benefit of the Vendor's successors or assigns.

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

8.11 The Purchaser may, in its sole discretion and at its sole expense register this Agreement to Purchase or notice thereof on title to the Lands.

8.12 Where each of the Vendor and the Purchaser retain a solicitor to complete this Agreement and where the transaction contemplated herein will be completed by electronic registration pursuant to Part III of the *Land Registration Reform Act*, R.S.O. 1990, c. L.4 and any amendments thereto, the Vendor and the Purchaser acknowledge and agree that the delivery of documents and the release thereof to the Vendor and the Purchaser may, at the solicitor's discretion; (a) not occur contemporaneously with the registration of the Transfer/Deed of Land (and other registrable) documentation), and (b) be subject to conditions whereby the solicitor receiving documents and/or money will be required to hold them in trust and not release them except in accordance with the terms of a written agreement between the solicitors

8.13 The provisions of the attached Schedules "A" and "B" shall form part of this Agreement as if set out herein.

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

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

8.16 The parties hereto agree that any representations or covenants contained in this 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 Agreement.

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

8.18 The Vendor covenants and agrees to execute if necessary, at no further cost or condition to the Purchaser except payment of the Vendor's reasonable out-of-pocket costs, such other instruments, plans and documents as may reasonably be required by the Purchaser to effect the registration of any right or interest transferred hereunder or notice of this Agreement on title to the Lands.

8.19 The Purchaser agrees to pay the Vendor's reasonable legal costs in connection with this transaction.

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

IN WITNESS WHEREOF the parties hereto have hereunto set their respective hands and seals to this Agreement of Purchase and Sale.

PURCHASER:

This Offer is dated the day of 20__.

	HYDRO ONE NETWORKS INC.
HYDRO ONE HST 870865821RT0001	Per: ______________________ Name: Thanh Lam Title: Senior Manager, Transmission Acquisition **I have authority to bind the Corporation**
	HYDRO ONE NETWORKS INC.
HYDRO ONE HST 870865821RT0001	Per: ______________________ Name: Ranjit Multani Title: Director, Land Acquisitions and Management **I have authority to bind the Corporation**

VENDOR:

The undersigned Vendor hereby accepts the above offer and covenants, promises and agrees to and with the Purchaser to duly carry out the same on the terms and conditions above mentioned.

Dated and accepted as at this day of 20___.

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

The undersigned Spouse of the Vendor hereby consents to the disposition evidenced herein pursuant to the provisions of the *Family Law Act*, R.S.O. 1990, c.F.3, and amendments thereto.

In consideration of One Dollar ($1.00), the receipt of which from the Purchaser is hereby acknowledged, the undersigned Spouse of the Vendor hereby agrees with the Purchaser that he/she will execute all necessary or incidental documents to give full force and effect to the sale evidenced herein.

WITNESS:	**SPOUSE OF VENDOR:**
	l/s
Name: «Real_Estate_Representative»	Name: **Property Vendor Spouse Name**

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

SCHEDULE “A”

The Property is more particularly described as follows:

«Legal_Description»

SCHEDULE “B”

PERMITTED ENCUMBRANCES

The parties agree that title on Closing may be subject to, and will be acceptable to the Purchaser, as follows:

[NTD: the Easement Agreement.]

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.

Page 2 of 4

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

SCHEDULE "A"

*Sketch for reference only, not to scale.

Page 4 of 4

THIS AGREEMENT made in duplicate the ___________day of ____________2021

Between:

XXXXXXXXX

(hereinafter referred to as the "Grantor")
OF THE FIRST PART

--- and ---

HYDRO ONE NETWORKS INC.

(hereinafter referred to as "HONI")
OF THE SECOND PART

WHEREAS the Grantor is the owner in fee simple and in possession of certain lands legally described as ***(INSERT LEGAL DESCRIPTION)*** **(the "Lands").**

WHEREAS The Grantor has entered into a Temporary Access Agreement with HONI on a portion of the Lands highlighted in green in Schedule "A" (the "Access Lands"). HONI will be utilizing a portion of the Lands as a means of off-corridor access highlighted in red in Schedule "A" ("Off-Corridor Access Lands").

WHEREAS the Owner is agreeable in allowing HONI to enter onto the Lands to use the Off-Corridor Access Lands in order to commence activities which shall include necessary real estate, environmental and engineering studies and testing including but not limited to borehole testing, archaeological studies, soil assessments, property appraisals and surveys in, on or below the Lands subject to the terms and conditions contained herein (the "Activities").

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the lump sum of **$XXXXX.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 Grantor hereby grants to HONI the right to enter upon the Lands for the purpose of Off-Corridor Access Lands.

2. The Grantor hereby grants to HONI, as of the date this Agreement, (i) the right to enter upon and exit from, and to pass and repass at any and all times in, over, along, upon, across, through and under the Off-Corridor Access Lands as may be reasonably necessary, at all reasonable times, for HONI and its respective officers, employees, workers, permittees, servants, agents, contractors and subcontractors, with or without vehicles, supplies, machinery, plant, material and equipment for the purpose of the Activities, subject to payment of compensation for damages including payment for crops caused thereby. HONI agrees that it shall take all reasonable care while undertaking the Activities.

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

4. Upon the expiry of the Term or any extension thereof, HONI shall repair any physical damage to the Off-Corridor Access Lands and/or Lands resulting from HONI's use of the Access Lands and the permission granted herein; and, shall restore the Access Lands to its original condition so far as possible and practicable.

5. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Off-Corridor Access Lands 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 Off-Corridor Access Lands or of its activities on or in connection with the Off-Corridor Access Lands 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 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 7S3

Attention:	Real Estate Acquisitions
Tel:	905-875-2508
Fax:	905-878-8356

TO GRANTOR:

XXXXXXXX
XXXXXXXX

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 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.

Page 2 of 4

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.

SIGNED, SEALED & DELIVERED In the presence of: ____________________________ Witness	**OWNER(S):** ____________________________ **Name:**
SIGNED, SEALED & DELIVERED In the presence of: ____________________________ Witness	____________________________ **Name:**

HYDRO ONE
HST # 870 865 821 RT001

HYDRO ONE NETWORKS INC.

By: ____________________________

Name:
Title:

I have authority to bind the Corporation

Page 3 of 4

SCHEDULE “A”

PROPERTY SKETCH

CROPLAND OUT-OF-PRODUCTION FOR 202X CROP GROWING SEASON

Full and Final Release

IN CONSIDERATION of the payment in the amount of **$XXXXXX ($00.00)** (the **"Settlement Amount"**) by Hydro One Networks Inc. to **«Owner_1_name_for_letters» & «Owner_2_name_for_letters» & «Owner_3_name_for_letters»** and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, each of the undersigned, on behalf of himself/herself, his/her heirs, executors, administrators, successors and assigns (hereinafter the "Releasors"), hereby releases and forever discharges **HYDRO ONE NETWORKS INC.** and its respective officers, directors, employees, servants and agents and its parent, affiliates, subsidiaries, and their respective successors and assigns (hereinafter collectively the "Releasee") jointly and severally from any and all actions, causes of action, claims and demands for damages, indemnity, costs, interest and loss or injury of every nature and kind whatsoever, howsoever arising, which the Releasors now have, may have had or may hereafter have arising from or in any way related or as a result of the loss of crop land being out of production for the 202X crop growing season on the lands legally described as **«Legal_Description» being PIN «PIN» (LT) (the "Property").**

The Releasors acknowledge that the Settlement Amount was calculated (hereto attached as Schedule "A") in accordance with the XXXXXXX Option set out in the Cropland Out–of-Production Booklet, as selected by the Releasors.

AND THE RELEASORS hereby confirm and acknowledge that for the XXXXXXX Option, any cropland out-of-production will not be offered to the Property Owner if the Property Owner transacts, sells, transfers, assigns, conveys or suspends agricultural operations on the lands subject to the Cropland Out-of-Production Program.

AND FOR THE SAID CONSIDERATION, the Releasors further agree not to make any claim or take any proceedings against any other person or corporation who might claim contribution or indemnity under the provisions of the *Negligence Act* and the amendments thereto from the persons or corporations discharged by the release.

AND THE RELEASORS hereby confirm and acknowledge that the Releasors have sought or declined to seek independent legal advice before signing this Release, that the terms of this Release are fully understood, and that the said amounts and benefits are being accepted voluntarily, and not under duress, and in full and final compromise, adjustment and settlement of all claims against the Releasees.

IT IS UNDERSTOOD AND AGREED that the said payment or promise of payment is deemed to be no admission whatsoever of liability on the part of the Releasees.

AND IT IS UNDERSTOOD AND AGREED that this Release may be executed in separate counterparts (and may be transmitted by email) each of which shall be deemed to be an original and that such counterparts shall together constitute one and the same instrument, notwithstanding the date of actual execution.

IN WITNESS WHEREOF, the Releasors have hereunto set their respective hands this _______ day of ___________, 202X.

SIGNED, SEALED AND DELIVERED
In the presence of)

____________________________________	___________________________(seal)
Print Name of Witness	*«Owner_1_name_for_letters»*
____________________________________	___________________________(seal)
Print Name of Witness	*«Owner_2_name_for_letters»*
______________________________	____________________________(seal)
Print Name of Witness	*«Owner_3_name_for_letters»*

HYDRO ONE NETWORKS INC.

Per: ___________________________________
Name:

Title:

I have authority to bind the Corporation

Page 2 of 3

Schedule "A"

The area of cropland out-of-production for the growing season of 202X being calculated and accepted by Releasors is shown below:

Page 3 of 3

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

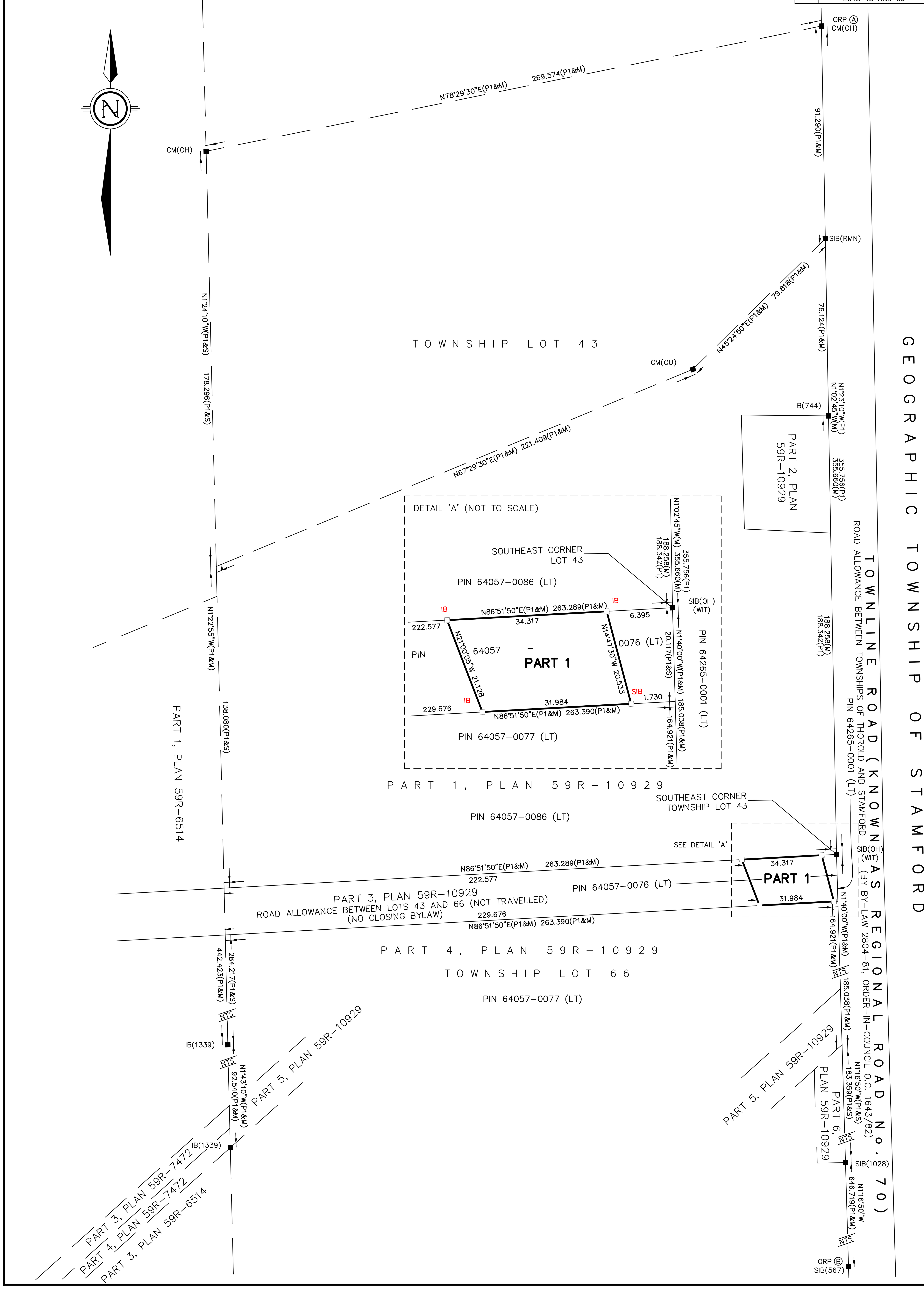
____
Signature

ATTACHMENT 11 - DESCRIPTION OF LANDS AND SPECIFIC INTERESTS IN LANDS OVER WHICH AUTHORITY TO EXPROPRIATE IS BEING REQUESTED

#	Hydro One's File No.	Municipality	Property Identification Number	Registered Property Owner Name(s)	Legal Description of Property (per Parcel Register)	General Description of Interest to be Expropriated	Name(s) of Other Registered Interest Holder(s) on Title	Type of Interest on Title	Instrument	Voluntary Land Rights Agreement Status *(as of Nov 6, 2025)*
1	A02	Thorold	64057-0076 (LT)	[redacted]	PT RDAL BTN TWP LTS 43 & 66 THOROLD BEING PT 3 ON 59R10929 ; S/T INTEREST OF MUNICIPALITY ; THOROLD	Permanent Easement (Corridor)	[redacted]	[redacted]	N/A	Voluntary Land Rights Agreement Offer Not Presented
2	B18	Welland	64431-0053 (LT)	[redacted]	PT LT 13, CON 2 CROWLAND , PART 12, 37 & 38 , 59R7332 ; S/T CR23043,CR31920; CITY OF WELLAND	Permanent Easement (Corridor)	[redacted]	[redacted]	CR23043 CR31920 SN734414 SN738478 SN444977	Voluntary Land Rights Agreement Offer Not Presented
3	B28	Welland	64432-0040 (LT)	[redacted]	PT LT 13, CON 3 CROWLAND , AS IN RO424566 (SECONDLY); T/W RO424566 ; S/T CR18046 WELLAND	Permanent Easement (Corridor)	[redacted]	[redacted]	CR18046	Voluntary Land Rights Agreement Offer Not Presented
4	C04	Welland	)	[redacted]	PT LT 16 CON 4 CROWLAND AS IN RO750264 & PT 45, 47, 49 & 51 59R935; S/T CR17935, CR22331, CR33045; WELLAND	Permanent Easement (Corridor)	[redacted]	[redacted]	CR17935 CR22331 CR33045 RO173874 RO194505 RO206430 RO223191 RO244321 RO254072 RO555679 RO666966 RO750263	Voluntary Land Rights Agreement Offer Not Presented

DRAFT EXPROPRIATION REFERENCE PLANS

S C H E D U L E				
PART	GEOGRAPHIC	PIN	AREA	NAME OF MOST RECENT TRANSFEREE
1	PART OF THE ROAD ALLOWANCE BETWEEN THOROLD TOWNSHIP LOTS 43 AND 66	PART OF PIN PIN 64057–0076 (LT)	666.6m²	[redacted]



PLAN OF SURVEY OF
PART OF THE ROAD ALLOWANCE BETWEEN THOROLD TOWNSHIP LOTS 43 AND 66
CITY OF THOROLD
REGIONAL MUNICIPALITY OF NIAGARA

TULLOCH GEOMATICS INC.
2025
SCALE 1:1000

10m 0 10 50m

THE INTENDED PLOT SIZE OF THIS PLAN IS 610mm IN WIDTH BY 610mm IN HEIGHT WHEN PLOTTED AT A SCALE OF 1:1000.

METRIC:

DISTANCES AND COORDINATES SHOWN ON THIS PLAN ARE IN METRES AND CAN BE CONVERTED TO FEET BY DIVIDING BY 0.3048.

DISTANCE NOTE:

GROUND DISTANCES SHOWN HEREON CAN BE CONVERTED TO UTM GRID BY MULTIPLYING BY A COMBINED SCALE FACTOR OF 0.999840.

BEARING NOTE:

BEARINGS ARE UTM GRID DERIVED FROM SIMULTANEOUS GNSS OBSERVATIONS FROM OBSERVED REFERENCE POINTS A AND B USING THE PRECISE POINT POSITIONING (PPP) SERVICE AND ARE REFERRED TO THE CENTRAL MERIDIAN OF UTM ZONE 17 (81°00' WEST LONGITUDE) NAD83 (CSRS) (2010.0).

ROTATION NOTE:

A ROTATION OF 1°13'10" COUNTER CLOCKWISE HAS BEEN APPLIED TO THE ASTRONOMIC BEARINGS OF UNDERLYING PLAN 59R–10929 TO ACCOUNT FOR DIFFERENT REFERENCE MERIDIANS.

LEGEND:

■	DENOTES FOUND MONUMENT
□	DENOTES PLANTED MONUMENT
CM	DENOTES CONCRETE MONUMENT
IB	DENOTES IRON BAR
SIB	DENOTES STANDARD IRON BAR
WIT	DENOTES WITNESS
N.T.S.	DENOTES NOT TO SCALE
ORP	DENOTES OBSERVED REFERENCE POINT
PIN	DENOTES PROPERTY IDENTIFICATION NUMBER
MMM	DENOTES MARSHALL, MACKLIN, MONAGHAN, O.L.S.
OH	DENOTES ONTARIO HYDRO
OU	DENOTES ORIGIN UNKNOWN
RMN	DENOTES REGIONAL MUNICIPALITY OF NIAGARA
567	DENOTES R.B. ERWIN, O.L.S.
744	DENOTES MATTHEWS, CAMERON, HEYWOOD KERRY T. HOWE SURVEYING LTD., O.L.S.
1028	DENOTES R.R. SCOTT, O.L.S.
M	DENOTES MEASURED
S	DENOTES SET
P1	DENOTES PLAN 59R–10929

INTEGRATION COORDINATE TABLE

OBSERVED REFERENCE POINTS DERIVED FROM GNSS OBSERVATIONS USING THE PRECISE POINT POSITIONING (PPP) SERVICE AND ARE REFERRED TO UTM ZONE 17 (81°00' WEST LONGITUDE), NAD83 (CSRS) (2010.0).

COORDINATES TO RURAL ACCURACY PER SECTION 14 (2) OF O.REG 216/10.

ORP	NORTHING	EASTING
A	4773802.939	648471.163
B	4772432.677	648501.573

COORDINATES CANNOT, IN THEMSELVES, BE USED TO RE–ESTABLISH THE CORNERS OR BOUNDARIES SHOWN ON THIS PLAN.

SURVEYOR'S CERTIFICATE

I CERTIFY THAT:

(1) THIS SURVEY AND PLAN ARE CORRECT AND IN ACCORDANCE WITH THE SURVEYS ACT, THE SURVEYORS ACT, AND THE LAND TITLES ACT AND THE REGULATIONS MADE UNDER THEM.

(2) THE SURVEY WAS COMPLETED ON THE XX DAY OF XXX, 2025.

DRAFT

DATE

MICHAEL J. MASCIOTRA
ONTARIO LAND SURVEYOR

THIS PLAN OF SURVEY RELATES TO AOLS PLAN SUBMISSION FORM NUMBER XXXXXXX.

TULLOCH
TULLOCH GEOMATICS INC.
5405 EGLINTON AVE. W
SUITE 202
ETOBICOKE, ON
M9C 5K6
T. 905 481.1678
toronto@tulloch.ca

DRAWN BY: SC | FILE: 252300–400–A02

ACAD FILE: P:\2025\252300\Geomatics\06 Production\Drafting (Rplans)\A02 64057–0076\252300–400–A02.DWG

SCHEDULE					
PART	LOT	CONCESSION	PIN	AREA	NAME OF MOST RECENT TRANSFEREE
1	PART OF LOT 13	2	PART OF PIN 64431–0053(LT)	903.4m²	[redacted]
2				236.7m²	

PART 1 IS SUBJECT TO EASEMENT AS IN CR23043.
PART 2 IS SUBJECT TO EASEMENT AS IN CR23043 AND CR31920.

DRAFT

PLAN OF SURVEY OF
PART OF LOT 13, CONCESSION 2
GEOGRAPHIC TOWNSHIP OF CROWLAND
NOW IN THE CITY OF WELLAND
REGIONAL MUNICIPALITY OF NIAGARA

TULLOCH GEOMATICS INC.
2025
SCALE 1:500

5m 0 5 25m

THE INTENDED PLOT SIZE OF THIS PLAN IS 610mm IN WIDTH BY 610mm IN HEIGHT WHEN PLOTTED AT A SCALE OF 1:500.

METRIC:

DISTANCES AND COORDINATES SHOWN ON THIS PLAN ARE IN METRES AND CAN BE CONVERTED TO FEET BY DIVIDING BY 0.3048.

DISTANCE NOTE:

GROUND DISTANCES SHOWN HEREON CAN BE CONVERTED TO UTM GRID BY MULTIPLYING BY A COMBINED SCALE FACTOR OF 0.999840.

BEARING NOTE:

BEARINGS ARE UTM GRID DERIVED FROM SIMULTANEOUS GNSS OBSERVATIONS FROM OBSERVED REFERENCE POINTS A AND B USING THE PRECISE POINT POSITIONING (PPP) SERVICE AND ARE REFERRED TO THE CENTRAL MERIDIAN OF UTM ZONE 17 (81°00' WEST LONGITUDE) NAD83 (CSRS) (2010.0).

ROTATION NOTE:

A ROTATION OF 1°13'25" COUNTER CLOCKWISE HAS BEEN APPLIED TO THE ASTRONOMIC BEARINGS OF UNDERLYING PLAN 59R–7332 TO ACCOUNT FOR DIFFERENT REFERENCE MERIDIANS.

LEGEND:

■	DENOTES FOUND MONUMENT
□	DENOTES PLANTED MONUMENT
IB	DENOTES IRON BAR
SIB	DENOTES STANDARD IRON BAR
SSIB	DENOTES SHORT STANDARD IRON BAR
ORP	DENOTES OBSERVED REFERENCE POINT
PIN	DENOTES PROPERTY IDENTIFICATION NUMBER
744	DENOTES MATTHEWS, CAMERON, HEYWOOD KERRY T. HOWE SURVEYING LTD., O.L.S.
1495	DENOTES P.D. REITSMA SURVEYING LTD, O.L.S.
1251	DENOTES ERIC EICHMANIS, O.L.S.
M	DENOTES MEASURED
S	DENOTES SET
P1	DENOTES PLAN 59R–7332
D1	DENOTES REGISTERED INSTRUMENT CR23043
D2	DENOTES REGISTERED INSTRUMENT CR31920

INTEGRATION COORDINATE TABLE

OBSERVED REFERENCE POINTS DERIVED FROM GNSS OBSERVATIONS USING THE PRECISE POINT POSITIONING (PPP) SERVICE AND ARE REFERRED TO UTM ZONE 17 (81°00' WEST LONGITUDE), NAD83 (CSRS) (2010.0).

COORDINATES TO RURAL ACCURACY PER SECTION 14 (2) OF O.REG 216/10.

ORP	NORTHING	EASTING
A	4764433.585	647530.712
B	4764409.172	647941.633

COORDINATES CANNOT, IN THEMSELVES, BE USED TO RE–ESTABLISH THE CORNERS OR BOUNDARIES SHOWN ON THIS PLAN.

SURVEYOR'S CERTIFICATE

I CERTIFY THAT:

(1) THIS SURVEY AND PLAN ARE CORRECT AND IN ACCORDANCE WITH THE SURVEYS ACT, THE SURVEYORS ACT, AND THE LAND TITLES ACT AND THE REGULATIONS MADE UNDER THEM.

(2) THE SURVEY WAS COMPLETED ON THE XX DAY OF XXX, 2025.

DRAFT

DATE

MICHAEL J. MASCIOTRA
ONTARIO LAND SURVEYOR

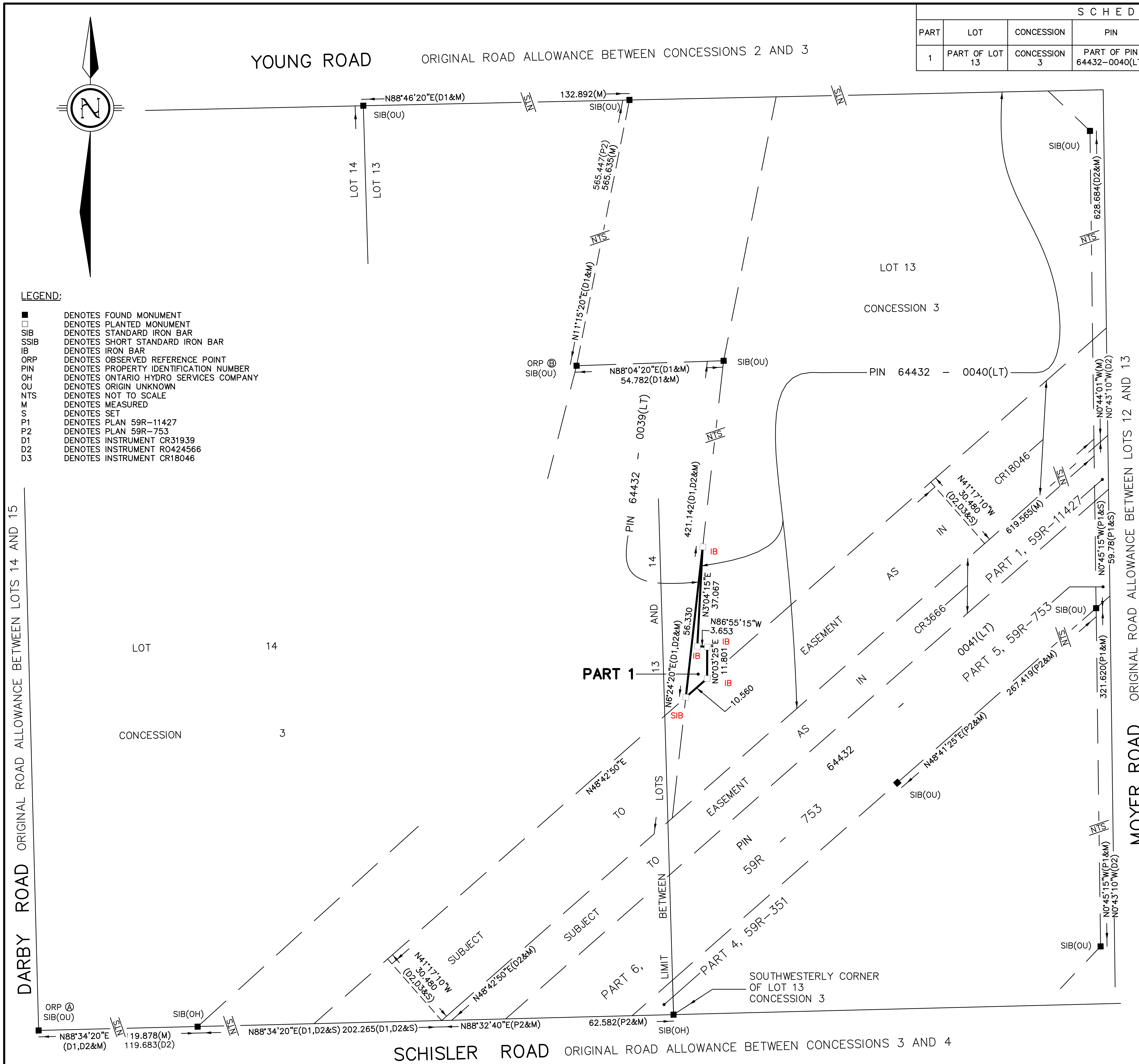
THIS PLAN OF SURVEY RELATES TO AOLS PLAN SUBMISSION FORM NUMBER XXXXXXX.

TULLOCH GEOMATICS INC.
5405 EGLINTON AVE. W
SUITE 202
ETOBICOKE, ON
M9C 5K6
T. 905 481.1678
toronto@tulloch.ca

DRAWN BY: SC | FILE: 252300–400–B18

ACAD FILE: P:\2025\252300\Geomatics\06 Production\Drafting (Rplans)\B18 64431–0053\252300–400–B18.DWG

SCHEDULE					
PART	LOT	CONCESSION	PIN	AREA	NAME OF MOST RECENT TRANSFEREE
1	PART OF LOT 13	CONCESSION 3	PART OF PIN 64432-0040(LT)	142.5m²	[redacted]



LEGEND:

- ■ DENOTES FOUND MONUMENT
- □ DENOTES PLANTED MONUMENT
- SIB DENOTES STANDARD IRON BAR
- SSIB DENOTES SHORT STANDARD IRON BAR
- IB DENOTES IRON BAR
- ORP DENOTES OBSERVED REFERENCE POINT
- PIN DENOTES PROPERTY IDENTIFICATION NUMBER
- OH DENOTES ONTARIO HYDRO SERVICES COMPANY
- OU DENOTES ORIGIN UNKNOWN
- NTS DENOTES NOT TO SCALE
- M DENOTES MEASURED
- S DENOTES SET
- P1 DENOTES PLAN 59R-11427
- P2 DENOTES PLAN 59R-753
- D1 DENOTES INSTRUMENT CR31939
- D2 DENOTES INSTRUMENT RO424566
- D3 DENOTES INSTRUMENT CR18046

PLAN OF SURVEY OF PART OF LOT 13, CONCESSION 3 GEOGRAPHIC TOWNSHIP OF CROWLAND CITY OF WELLAND REGIONAL MUNICIPALITY OF NIAGARA

TULLOCH GEOMATICS INC.
2025
SCALE 1:1000

10m 0 10 50m

THE INTENDED PLOT SIZE OF THIS PLAN IS 610mm IN WIDTH BY 457mm IN HEIGHT WHEN PLOTTED AT A SCALE OF 1:1000.

METRIC:

DISTANCES AND COORDINATES SHOWN ON THIS PLAN ARE IN METRES AND CAN BE CONVERTED TO FEET BY DIVIDING BY 0.3048.

DISTANCE NOTE:

GROUND DISTANCES SHOWN HEREON CAN BE CONVERTED TO UTM GRID BY MULTIPLYING BY A COMBINED SCALE FACTOR OF 0.999840.

BEARING NOTE:

BEARINGS ARE UTM GRID DERIVED FROM SIMULTANEOUS GNSS OBSERVATIONS FROM OBSERVED REFERENCE POINTS A AND B USING THE PRECISE POINT POSITIONING (PPP) SERVICE AND ARE REFERRED TO THE CENTRAL MERIDIAN OF UTM ZONE 17 (81°00' WEST LONGITUDE) NAD83 (CSRS) (2010.0).

ROTATION NOTE:

A ROTATION OF 1°12'40" COUNTER CLOCKWISE HAS BEEN APPLIED TO THE ASTRONOMIC BEARINGS OF UNDERLYING INSTRUMENT RO424566 AND CR31939 TO ACCOUNT FOR DIFFERENT REFERENCE MERIDIANS.

A ROTATION OF 1°02'40" COUNTER CLOCKWISE HAS BEEN APPLIED TO THE ASTRONOMIC BEARINGS OF UNDERLYING PLAN 59R-753 TO ACCOUNT FOR DIFFERENT REFERENCE MERIDIANS.

INTEGRATION COORDINATE TABLE		
OBSERVED REFERENCE POINTS DERIVED FROM GNSS OBSERVATIONS USING THE PRECISE POINT POSITIONING (PPP) SERVICE AND ARE REFERRED TO UTM ZONE 17 (81°00' WEST LONGITUDE), NAD83 (CSRS) (2010.0).		
COORDINATES TO RURAL ACCURACY PER SECTION 14 (2) OF O.REG 216/10.		
ORP	NORTHING	EASTING
A	4762743.022	647186.234
B	4763243.217	647586.291
COORDINATES CANNOT, IN THEMSELVES, BE USED TO RE-ESTABLISH THE CORNERS OR BOUNDARIES SHOWN ON THIS PLAN.		

SURVEYOR'S CERTIFICATE

I CERTIFY THAT:

(1) THIS SURVEY AND PLAN ARE CORRECT AND IN ACCORDANCE WITH THE SURVEYS ACT, THE SURVEYORS ACT, AND THE LAND TITLES ACT AND THE REGULATIONS MADE UNDER THEM.

(2) THE SURVEY WAS COMPLETED ON THE XX DAY OF XXX, 2025.

DRAFT

DATE

MICHAEL J. MASCIOTRA
ONTARIO LAND SURVEYOR

THIS PLAN OF SURVEY RELATES TO AOLS PLAN SUBMISSION FORM NUMBER XXXXXXX.

TULLOCH
TULLOCH GEOMATICS INC.
5405 EGLINTON AVE. W
SUITE 202
ETOBICOKE, ON
M9C 5K6
T. 905 481.1678
toronto@tulloch.ca

DRAWN BY: SC | FILE: 252300-400-B28

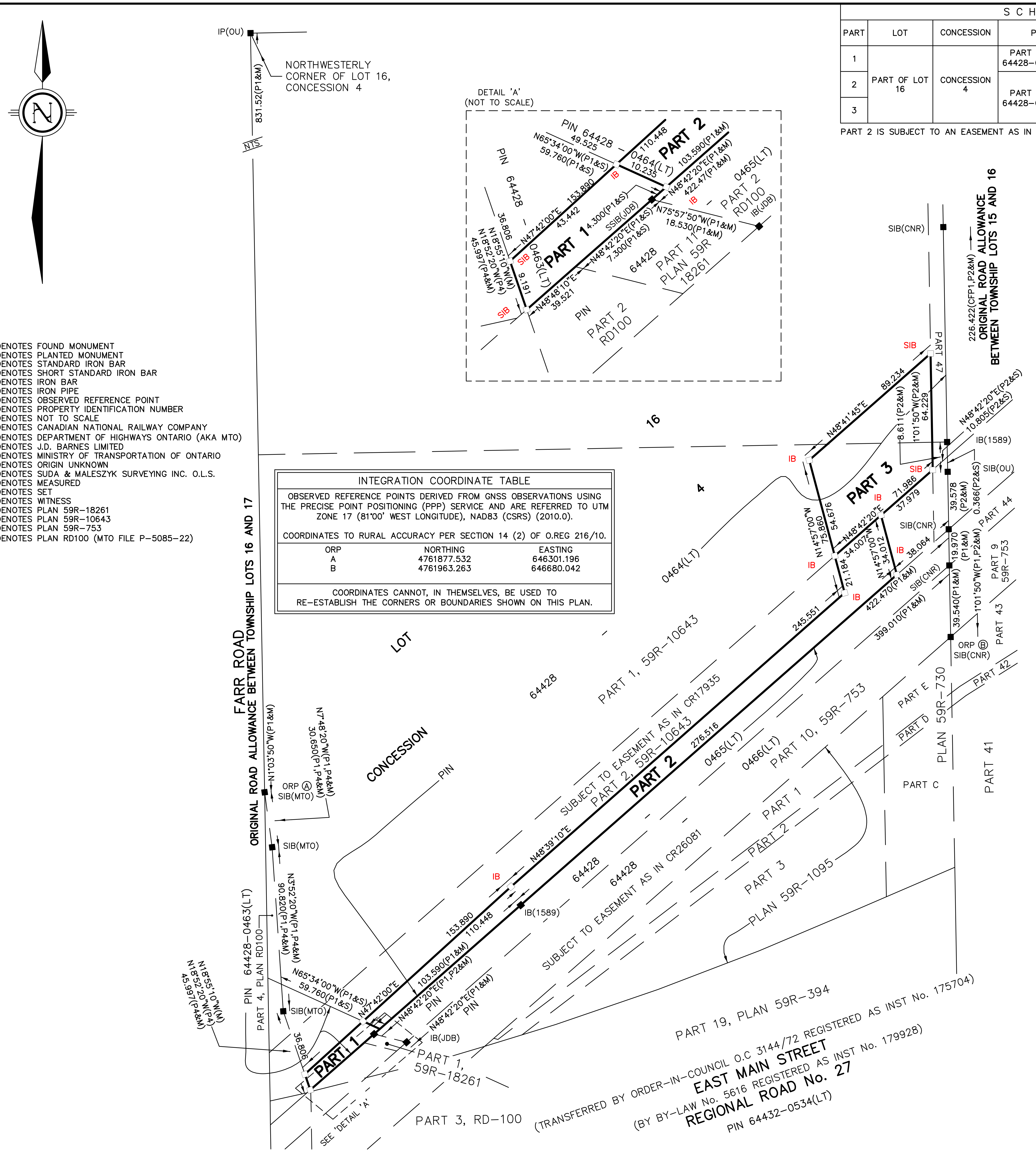
ACAD FILE: P:\2025\252300\Geomatics\06 Production\Drafting (Rplans)\B28 64432-0040\B18 64431-0053\252300-400-B28.DWG

SCHEDULE

PART	LOT	CONCESSION	PIN	AREA	NAME OF MOST RECENT TRANSFEREE
1	PART OF LOT 16	CONCESSION 4	PART OF PIN 64428-0463(LT)	421.9m^2	[redacted]
2			PART OF PIN 64428-0464(LT)	4916.8m^2	
3				3950.0m^2	

PART 2 IS SUBJECT TO AN EASEMENT AS IN CR17935

DRAFT



INTEGRATION COORDINATE TABLE

OBSERVED REFERENCE POINTS DERIVED FROM GNSS OBSERVATIONS USING THE PRECISE POINT POSITIONING (PPP) SERVICE AND ARE REFERRED TO UTM ZONE 17 (81°00' WEST LONGITUDE), NAD83 (CSRS) (2010.0).

COORDINATES TO RURAL ACCURACY PER SECTION 14 (2) OF O.REG 216/10.

ORP	NORTHING	EASTING
A	4761877.532	646301.196
B	4761963.263	646680.042

COORDINATES CANNOT, IN THEMSELVES, BE USED TO RE-ESTABLISH THE CORNERS OR BOUNDARIES SHOWN ON THIS PLAN.

LEGEND:

■	DENOTES FOUND MONUMENT
□	DENOTES PLANTED MONUMENT
SIB	DENOTES STANDARD IRON BAR
SSIB	DENOTES SHORT STANDARD IRON BAR
IB	DENOTES IRON BAR
IP	DENOTES IRON PIPE
ORP	DENOTES OBSERVED REFERENCE POINT
PIN	DENOTES PROPERTY IDENTIFICATION NUMBER
NTS	DENOTES NOT TO SCALE
CNR	DENOTES CANADIAN NATIONAL RAILWAY COMPANY
DHO	DENOTES DEPARTMENT OF HIGHWAYS ONTARIO (AKA MTO)
JDB	DENOTES J.D. BARNES LIMITED
MTO	DENOTES MINISTRY OF TRANSPORTATION OF ONTARIO
OU	DENOTES ORIGIN UNKNOWN
1589	DENOTES SUDA & MALESZYK SURVEYING INC. O.L.S.
M	DENOTES MEASURED
S	DENOTES SET
WIT	DENOTES WITNESS
P1	DENOTES PLAN 59R-18261
P2	DENOTES PLAN 59R-10643
P3	DENOTES PLAN 59R-753
P4	DENOTES PLAN RD100 (MTO FILE P-5085-22)

PLAN OF SURVEY OF PART OF LOT 16, CONCESSION 4 GEOGRAPHIC TOWNSHIP OF CROWLAND NOW IN THE CITY OF WELLAND REGIONAL MUNICIPALITY OF NIAGARA

TULLOCH GEOMATICS INC.
2025
SCALE 1:1500

15m 0 15 75m

THE INTENDED PLOT SIZE OF THIS PLAN IS 610mm IN WIDTH BY 457mm IN HEIGHT WHEN PLOTTED AT A SCALE OF 1:1500.

METRIC:

DISTANCES AND COORDINATES SHOWN ON THIS PLAN ARE IN METRES AND CAN BE CONVERTED TO FEET BY DIVIDING BY 0.3048.

DISTANCE NOTE:

GROUND DISTANCES SHOWN HEREON CAN BE CONVERTED TO UTM GRID BY MULTIPLYING BY A COMBINED SCALE FACTOR OF 0.999840.

BEARING NOTE:

BEARINGS ARE UTM GRID DERIVED FROM SIMULTANEOUS GNSS OBSERVATIONS FROM OBSERVED REFERENCE POINTS A AND B USING THE PRECISE POINT POSITIONING (PPP) SERVICE AND ARE REFERRED TO THE CENTRAL MERIDIAN OF UTM ZONE 17 (81°00' WEST LONGITUDE) NAD83 (CSRS) (2010.0).

ROTATION NOTE:

A ROTATION OF 1°07'20" COUNTER CLOCKWISE HAS BEEN APPLIED TO THE ASTRONOMIC BEARINGS OF UNDERLYING PLAN 59R-10643 TO ACCOUNT FOR DIFFERENT REFERENCE MERIDIANS.

A ROTATION OF 1°02'00" COUNTER CLOCKWISE HAS BEEN APPLIED TO THE ASTRONOMIC BEARINGS OF UNDERLYING PLAN 59R-753 TO ACCOUNT FOR DIFFERENT REFERENCE MERIDIANS.

A ROTATION OF 1°07'50" COUNTER CLOCKWISE HAS BEEN APPLIED TO THE ASTRONOMIC BEARINGS OF UNDERLYING PLAN RD100 (MTO FILE P-5085-22) TO ACCOUNT FOR DIFFERENT REFERENCE MERIDIANS.

SURVEYOR'S CERTIFICATE

I CERTIFY THAT:

(1) THIS SURVEY AND PLAN ARE CORRECT AND IN ACCORDANCE WITH THE SURVEYS ACT, THE SURVEYORS ACT, AND THE LAND TITLES ACT AND THE REGULATIONS MADE UNDER THEM.

(2) THE SURVEY WAS COMPLETED ON THE XX DAY OF XXX, 2025.

DRAFT

DATE

MICHAEL J. MASCIOTRA
ONTARIO LAND SURVEYOR

THIS PLAN OF SURVEY RELATES TO AOLS PLAN SUBMISSION FORM NUMBER XXXXXXX.

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SYSTEM IMPACT ASSESSMENT

Please refer to **Attachment 1** of this Schedule for the Final SIA prepared by the IESO (SIA reference # CAA 2024-811).

The Final SIA concludes that 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.

Hydro One confirms that it will implement the requirements noted by the IESO in the SIA.

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System Impact Assessment Report

Final Report - Public

CAA ID: 2024-811
Project: Crowland TS - Welland-Thorold 230kV Power Line
Connection Applicant: Hydro One Networks Inc.

November 19, 2025

ieso
Connecting Today.
Powering Tomorrow.

Acknowledgement

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

Disclaimers

IESO

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.

Hydro One

The results reported in this report are based on the information available to Hydro One, at the time of the study, suitable for a System Impact Assessment of this connection proposal.

The short circuit and thermal loading levels have been computed based on the information available at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed facilities on load and generation customers.

In this report, short circuit adequacy is assessed only for Hydro One circuit breakers. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One circuit breakers and identifying upgrades required to incorporate the proposed facilities. These results should not be used in the design and engineering of any new or existing facilities. The necessary data will be provided by Hydro One and discussed with any connection applicant upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and facility loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed facilities have been identified to the extent permitted by a System Impact Assessment under the current IESO Connection Assessment and Approval process. Additional facility studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

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Project Description

Hydro One Networks Inc. (the "connection applicant", the "transmitter") is proposing to transfer the existing Crowland Transformer Station (TS) from Allanburg 115 kV area to 230kV supply (the "project"). The project consists of the following:

- A new 18 km 230 kV double-circuit transmission circuit that will connect the Crowland TS to the existing 230 kV transmission circuits Q24HM/Q29HM at a point approximately 12.3 km from Sir Adam Beck 2 Generation Station (GS). Each circuit will have one load interrupting 230 kV circuit switcher at the tap location.
- Two new 215.5/28/28 kV power transformers at new Crowland TS. Each transformer will connect the two 27.6 kV buses, one winding to each bus.
- To allow proper protection of Q29HM and Q24HM circuits after the project, Hydro One Networks Inc. will sectionalize the Q29HM and Q24HM circuits by adding an inline breaker on each circuit about 14 km away from Beck 2 TS, west of the connection point for the project.

  After the sectionalization, Q29HM becomes E29HM and Q29E, and Q24HM becomes E24HM and Q24E, and the inline breakers at the new switching station (Crowland SS) are called L29L29 and L24L24, respectively. Note that the nomenclature for the sectionalized circuits is for the SIA purpose only and subject to change during the Market Registration.

The planned in-service date for the project is Q3 2029, with the peak forecasted load of 121.1 MW in 2039.

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 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.

2. The connection applicant shall ensure that the BPS elements are in compliance with the applicable NPCC criteria and the BES elements in compliance with the applicable NERC reliability standards. To determine the standard requirements that are applicable, the IESO provides mapping tools titled "NPCC Criteria Mapping Spreadsheet" for BPS elements and "NERC Reliability Standard Mapping Tool/Spreadsheet" for BES elements at the IESO's website of Applicability Criteria for Compliance with Reliability Requirements.

   Note, the connection applicant may request an exception to the application of the BES definition. The procedure for submitting an application for exemption can be found in Market Manual 11.4: "Ontario Bulk Electric System (BES) Exception" at the IESO's website.

   The IESO's criteria for determining applicability of NERC reliability standards and NPCC Criteria can be found in the Market Manual 11.1: "Applicability Criteria for Compliance with NERC Reliability Standards and NPCC Criteria" at the IESO's website.

   Compliance with these reliability standards will be monitored and assessed as part of the IESO's Ontario Reliability Compliance Program. For more details about compliance with applicable reliability standards reliability standards, the connection applicant is encouraged to contact orcp@ieso.ca and also visit the Ontario Reliability Compliance Program webpage.

   However, like any other system element in Ontario, the BPS and BES classifications of the project will be periodically re-evaluated as the electrical system evolves.

3. In accordance with Appendix 4.3 of the Market Rules, the connection applicant shall ensure the project has the capability to ride-through routine switching events and design criteria contingencies on the transmission system assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times, unless disconnection by configuration or a lower level ride-through capability has been approved by the IESO.

   The connection applicant will be required to demonstrate the project's voltage ride-through capability during commissioning by either providing manufacturer test results or monitoring several variables under a set of IESO specified field tests, and the test results must be verifiable using the dynamic models provided for the project.

   The connection applicant will be required to take corrective actions, that could include upgrades to the project, if the performance of their facilities becomes inadequate or causes any adverse impact on the IESO-controlled grid (e.g. tripping for out of zone faults) after the project is in-service. If upgrades are needed, the IESO may direct the transmitter or the distributor to disconnect the project until such upgrades are being deployed, to the satisfaction of the IESO. Automatic reconnection of the loads to the system is not allowed.

The IESO may require changes to voltage ride-through settings based on updates in NERC or Market Rules requirements. Changes to these settings shall not be enabled without IESO approval.

4. In accordance with Appendix 4.3 of the Market Rules, the connection applicant shall ensure the project have the capability to maintain the power factor within the range of 0.9 lagging and 0.9 leading as measured at the defined meter point of the project.

5. The connection applicant shall ensure that the project's equipment meet the voltage requirements specified in section 4.2 and section 4.3 of the Ontario Resource and Transmission Assessment Criteria (ORTAC).

6. 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.

   The connection applicant shall ensure that the circuit breakers/switchers installed at the project have rated interrupting time that satisfies Appendix 2 of the TSC. Fault interrupting devices installed at the project must be able to interrupt fault currents at the applicable maximum continuous voltage as specified in Section 4.2 and Section 4.3 of ORTAC.

7. The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the TSC. New protection systems must be coordinated with existing protection systems. Protection systems within the project shall only trip the appropriate equipment isolating the fault.

   Associated overvoltage protective relaying must be set to ensure that the project's equipment does not automatically trip for voltages up to 5% above the equipment's corresponding maximum continuous voltage as specified in section 4.2 of the ORTAC.

   BPS elements are deemed by the IESO to be essential to system reliability and security and must be protected by redundant protection systems in accordance with Section 8.2 of the TSC. These redundant protection systems must satisfy all requirements of the TSC, and in particular, they must be physically separated and not use common components, common battery banks, or common instrument transformer secondary windings.

   The protection systems for transmission voltage BES elements (whose rated voltage is higher than 100 kV) must be redundant. Redundancy must be present in protective relaying for normal fault clearing and control circuitry associated with protective functions including trip coils of the circuit breakers or other interrupting devices. These redundant protection systems must not use common instrument transformer secondary windings. A single communication system, if used, must be monitored and reported and a single DC supply, if used, must be monitored and reported for both low voltage and open circuit.

As the electrical system evolves, transmission voltage non-BPS or non-BES elements (whose rated voltage is higher than 100 kV) within the project, may be re-classified as BPS elements or BES elements. The connection applicant is recommended to design the protection systems for these elements according to the protection requirements for BPS elements or have adequate provisions for future upgrade to meet those requirements.

As currently assessed, the project is not required to participate in a Remedial Action Scheme (RAS). However, the IESO recommends that the connection applicant include adequate provision in the design of the project's protections and controls to allow for future installation of RAS equipment, and ensure that the RAS can be implemented should such a requirement arise in the future. If the project is required to participate in a RAS, its RAS facilities must comply with the NPCC Reliability Reference Directory #7 for Type 1 RAS and NERC RAS Standards. In particular, if the RAS is designed to have redundant 'A' and 'B' protection systems at a single location, they must be on different non-adjacent vertical mounting assemblies or enclosures. Two independent trip coils are required on any breakers to be selected for L/R as part of a RAS design.

8. The connection applicant has a total peak load at all its owned facilities, including the project, which is greater than 25 MW. According to Section 10.4.6 of Chapter 5 of the Market Rules and Section 11.3 of the Market Manual 7.1, the connection applicant is required to participate in the automatic Under-Frequency Load Shedding (UFLS) program and must select 35% of total peak load among its owned facilities for under-frequency tripping, based on a date and time specified by the IESO that approximates system peak, according to Section 10.4 of Chapter 5 of the Market Rules.

   The UFLS relay connected loads shall be set to achieve the amounts to be shed as stated in Section 11.3 of Market Manual 7.1. Table 1: UFLS relay settings summarizes UFLS relay settings as a function of the total peak load of all facilities, including the project, owned by the connection applicant.

Table 1: UFLS relay settings

Aggregate Summer Peak Load	UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)	Load Shed at stage as % of Connection Applicant's Load	Cumulative Load Shed at stage as % of Connection Applicant's Load
25 MW or more and less than 50 MW	1	59.5	0.3	≥ 35	≥ 35
50 MW or more and less than 100 MW	1	59.5	0.3	≥ 17	≥ 17
	2	59.1	0.3	≥ 18	≥ 35
100 MW or greater	1	59.5	0.3	7 – 9	7 – 9
	2	59.3	0.3	7 – 9	15 – 17
	3	59.1	0.3	7 – 9	23 – 25
	4	58.9	0.3	7 - 9	32 - 34
	Anti-Stall	59.5	10.0	3 – 4	35 - 37

The connection applicant, in conjunction with the transmitter, must also ensure that capacitor banks connected to the same station bus as the load are shed by UFLS facilities at 59.5 Hz with a time delay of 3 seconds.

The maximum load that can be connected to any single UFLS relay is 150 MW to ensure that the inadvertent operation of a single under-frequency relay during the transient period following a system disturbance does not lead to further system instability.

The IESO will review the requirements annually and inform the relevant market participants of their automatic UFLS obligations.

9. The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient conditions. Failures of the connection equipment must be contained within the project and have no adverse impact on the IESO-controlled grid.

10. In accordance with Section 7.5 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.17 of the Market Rules on a continual basis. The data shall be provided in accordance with the performance standards set forth in Appendix 4.22, subject to Section 7.6A of Chapter 4 of the Market Rules. The whole telemetry list will be finalized during the IESO's Market Registration process.

    The connection applicant must install monitoring equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2 of the Market Rules. As part of the IESO's Market Registration process, the connection applicant must also complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO's final approval to connect any phase of the project is granted.

11. The connection applicant must initiate the IESO's Market Registration process at least eight months prior to the commencement of any project related outages.

    The connection applicant is required to provide "as-built" equipment data for the project during the IESO Market Registration process. If the submitted equipment data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

    At the sole discretion of the IESO, performance tests may be required at generation and transmission facilities. The objectives of these tests are to demonstrate that equipment performance meets the IESO requirements, and to confirm models and data are suitable for IESO purposes. The transmitter may also have its own testing requirements. The IESO and the transmitter will coordinate their tests, share measurements and cooperate on analysis to the extent possible.

    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

    Be advised that any registration changes could have an impact on a market participant's monthly global adjustment charges. Such registration changes include but are not limited to:

    - New facility registrations
    - Modifications to existing facility registration
    - Electrical configuration changes
    - Meter installation reconfigurations
    - Full or partial transfers of a facility to a separate legal entity
    - Transferring a facility between the retail electricity market and the IESO-administered wholesale electricity market (IAM)

    Note that any newly registered facility in the IAM will automatically be treated as a Class B facility, unless stated otherwise in Ontario Regulation 429/04. It is the sole responsibility of the market participant to declare if any such provisions of Ontario Regulation 429/04 are applicable.

    Subject to compliance with all regulatory requirements, a new facility may become eligible to participate in the Industrial Conservation Initiative (ICI) program (i.e. to be treated as a Class A facility) after the facility has been registered in the IAM for the entire duration of a base period (i.e. the facility has registered withdrawals from the IESO-controlled grid from May 1 to April 30 of the following calendar year).

12. The connection applicant shall ensure that wholesale revenue metering installations comply with Chapter 6 of the Market Rules. This includes any intermediate project stages such as installation of temporary equipment or the use of mobile transformers. For more details, the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group in early stages of project design.

13. If the connection applicant is currently a participant in the Ontario Power System Restoration Plan, its restoration participant attachment is required to be updated to include the project

according to Market Manual 7.8. For either an existing or newly identified participant in the Ontario Power System Restoration Plan, details regarding restoration participant requirements will be finalized during the IESO Market Registration process.

If the project is classified as a Key Facility that is required to establish a Basic Minimum Power System following a system blackout, it shall meet testing requirements of Critical Components belonging to Key Facilities as specified in Market Manual 7.8. Key Facility, Basic Minimum Power System and Critical Component terms are defined in the NPCC Glossary of Terms.

14. 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.

    The connection applicant will be required to also provide updates and notifications in order for the IESO to determine if the project is "committed" as per Section 3.3 of Market Manual 1.4: Connection Assessment and Approval.

Appendix B: Project Data (Confidential)

Appendix C: Facility Classifications and Additional Telemetries (Confidential)

Appendix D: Study Scope of Work (Confidential)

Appendix E: Detailed Study Results (Confidential)

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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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Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

CUSTOMER IMPACT ASSESSMENT

NEW 230kV SUPPLY INTO WELLAND AREA

CIA ID: 2025-32
Revision: Final
Date: November 21 2025

Issued by**:**
Transmission System Planning
Hydro One Networks Inc.

Disclaimer

This Customer Impact Assessment was prepared based on preliminary information available about the new 230kV supply into Welland Area in the Niagara area. It is intended to highlight significant impacts, if any, to affected transmission customers early in the project development process and thus allow an opportunity for these parties to bring forward any concerns that they may have, including those needed for the review of the connection and for any possible application for Leave to Construct. Subsequent changes to the required modifications or the implementation plan may affect the impacts of the proposed connection identified in this Customer Impact Assessment. The results of this Customer Impact Assessment and the estimate of any outage requirements are subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements. The fault levels computed as part of this Customer Impact Assessment are meant to assess current conditions in the study horizon and are not intended to be for the purposes of sizing equipment or making other project design decisions. Many other factors beyond the existing fault levels go into project design decisions.

Hydro One Networks Inc. shall not be liable, whether in contract, tort or any other theory of liability, to any person who uses the results of the Customer Impact Assessment under any circumstances whatsoever for any damages arising out of such use unless such liability is created under some other contractual obligation between Hydro One Networks Inc. and such person.

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CUSTOMER IMPACT ASSESSMENT

NEW 230KV SUPPLY INTO WELLAND AREA

1.0 INTRODUCTION

Hydro One is proposing supplying the Welland Area with a new double 230kV transmission circuit and new 230kV-27.6kV DESN at Crowland TS to meet the expected growth in the area.

This Customer Impact Assessment (CIA) study assesses the potential impact of the new 230kV double circuit on the transmission customers in the Niagara area.

In accordance with Section 6 of the Ontario Energy Board's Transmission System Code ("TSC"), Hydro One Networks Inc. ("Hydro One") is to carry out a Customer Impact Assessment ("CIA") study to assess the potential impact of the proposed project on existing transmission customers in the affected area. As part of the Connection Assessment and Approval ("CAA") process, impact of the project on the bulk electricity system is the subject of the System Impact Assessment ("SIA"), which was carried out by the Independent Electricity System Operator ("IESO").

This study is intended to supplement the IESO System Impact Assessment (SIA) report CAA ID 2024-811 Crowland TS: Welland-Thorold 230kV Power Line, dated November 19 2025 for the proposed new 230kV supply into the Welland area.

This Customer Impact Assessment (CIA) study report is being issued to all area transmission customers being affected by the proposed work for review and comments.

This study does not evaluate the overall impact of the new 230kV double circuits on the bulk system. The impact of the new generator on the bulk system is the subject of the System Impact Assessment (SIA) which is issued by the Independent Electricity System Operator (IESO).

This study does not evaluate the impact of the new 230kV double circuits on the existing network Protection and Control facilities. Protection and Control aspects will be reviewed during the preparation of the Connection Cost Estimate and will be reflected in the Connection and Cost Recovery Agreement.

2.0 BACKGROUND

The most recent Niagara Integrated Regional Resource Plan (IRRP) highlights a growing electricity demand in the Welland region, especially south of Allanburg Transformer Station (TS). This future load will increase loading on the four (4) Hydro One 230kV/115kV Allanburg autotransformers, which, during certain multiple contingencies, approach its limited time ratings. With this expected growth in the area, expansion of the transmission system in the area is required. Welland, the area south of Allanburg TS is served by two 115kV circuits, A6C/A7C.

To alleviate this issue, Hydro One will be building a double 230kV transmission circuit and new 230kV-27.6kV DESN at Crowland TS to support the expected increasing load south of Allanburg TS.

The Project will construct approximately 18.5 km of new transmission line inclusive of 11 km of new 230 kV double circuit transmission line and 7.5 km of a new triple circuit transmission line (two 230 kV circuits, single 115 kV circuit) initiating from Abitibi Consolidated Junction to Crowland TS. To adequately protect the new and existing 230kV circuits, 230kV high voltage breakers will be installed to sectionalize the Q24HM and Q29HM circuits between Beck 2 TS and Beach/Middleport TS.

No electrical connection changes are planned for the 115kV system, aside from transferring the existing Crowland TS load to the newly established 230kV system.

The expected in-service date of the new multi 230kV double and 115kV single circuit and 230kV Crowland TS is October 2029.

Figure 1 shows the simplified single-line diagram of the new transmission facilities.

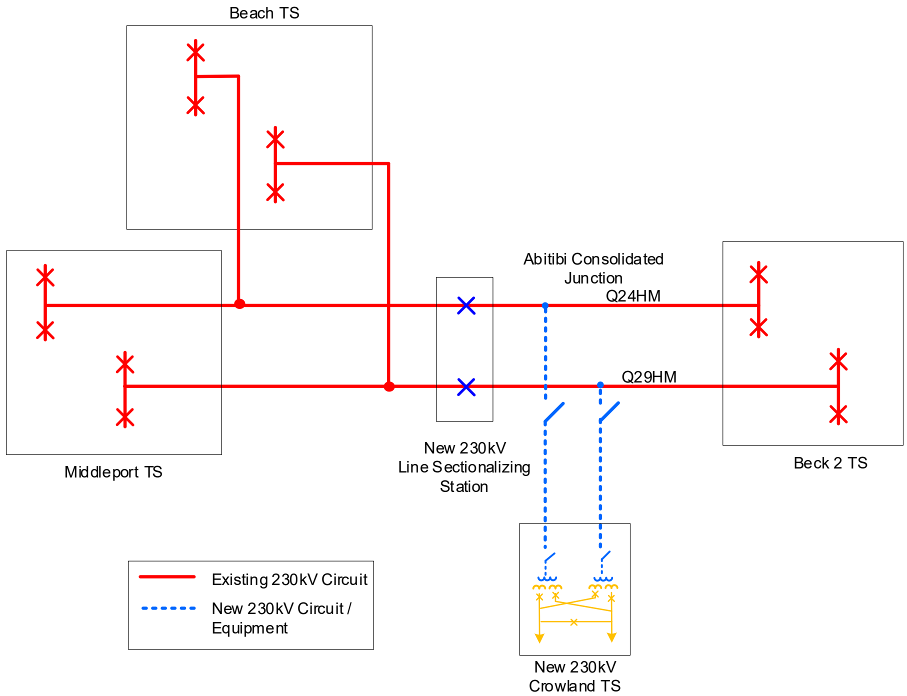

Figure 1: Simplified Single-Line Diagram of the new 230kV circuit and Crowland TS

3.0 CONNECTED CUSTOMERS

The purpose of the CIA is to assess the impact of the proposed facility upgrade on customers connected to Hydro One's transmission system between Beck GS # 2, Beach TS and Middleport TS. Table 1 summarizes the customers connected at each station.

Station	Customers
Sir Adam Beck SS #2	Ontario Power Generation
Crowland TS	Welland Hydro
ASW Steel TS	ASW Steel

Table 1: Connected Customers

4.0 CIA ASSESSMENT

4.1 Load Flow & System Study

Load flow and system study was performed by the IESO and it was concluded in the SIA report CAA ID 2024-811 that the proposed connection of this project does not have any significant impact on the system load flow.

Bus Location	Pre-Contingency Voltage[1]	Loss of Q24HM (Beck x New SS)		Loss of Q29HM (Beck x New SS)	
	kV	kV	Delta	kV	Delta
Sir Adam Beck #2 SS	239.1	238.8	-0.1%	238.8	-0.1%
Abitibi Consolidated Junction – Q24HM	238.7	-	-	237.2	-0.6%
Abitibi Consolidated Junction – Q29HM	238.8	237.2	-0.6%	-	-
Crowland TS – HV Q24HM	237.4	-	-	234.0	-1.4%
Crowland TS – HV Q29HM	237.4	234.0	-1.4%	-	-
Crowland TS – K Bus	28.8	29.0	0.7%	29.0	0.7%
Crowland TS – J Bus	28.8	29.0	0.7%	29.0	0.7%

[1] Based on IESO Summer 2025 base case

The new 230kV double circuit meets all voltage requirements before and after tap changer action following a contingency.

4.2 Short Circuit Study

The fault levels for the stations in the area are not expected to have any impact as a result of the new 230kV circuits.

The short circuit levels at the area HV buses are given in the table below. The local customer is advised to review the short circuit results to ensure that their equipment ratings are adequate for the fault current level.

Bus Name	Base kV	Prefault kV	Fault Level (kA) [1]				Breaker Ratings (kA)	
			3-phase		Line to Ground			
			Sym	Asym[2]	Sym	Asym[2]	Sym	Asym
Abitibi Consolidated Junction	**220**	250	20.4	22.3	16.0	16.7	-	-
Crowland TS	**220**	250	9.8	10.9	7.0	7.5	63	80
Crowland TS - J Bus (DER)	**27.6**	29	15.1	19	12.4	15.7	40	40
Crowland TS - K Bus	**27.6**	29	12.6	16.4	10.0	13.2	40	40
ASW Steel Jct	**118.1**	127	9.9	10.1	7.1	7.5	-	-

[1] Based on 2025 IESO Basecase.
[2] Based on contact parting time of 33ms for 220kV and 118kV, 50ms for 27.6kV

4.3 Customer Reliability & Outages Impact

The proposed new 230kV double circuit will require sectionalizing the Q29HM and Q24HM circuits by adding an inline breaker on each circuit approximately 14 kilometres away from Sir Adam Beck 2 TS.

The existing protection scheme for transmission circuits Q24HM and Q29HM employs a three-terminal line current differential system, supervised by a distance-based Directional Direct Over-

Reaching (DOR/T) scheme. This setup utilizes ‘A’ and ‘B’ Intelligent Electronic Devices (IEDs) located at Beck 2 TS, Beach TS, and Middleport TS. However, this configuration is insufficient to provide adequate protection for the newly added 230kV circuit. To resolve this protection problem, it is necessary to sectionalize the existing 230kV Q24HM and Q29HM circuits approximately 25 kilometres west of the Abitibi Consolidated Junction.

Having high voltage sectionalizing breakers will allow Hydro One to adequately detect, trip and isolate all faults along the new and sectionalized 230kV circuits. Faults along 230kV circuits will be cleared by the HV breaker and are expected to have minimum impact on the customers supplied by the local 230kV circuits.

It is to be noted that some outages may be required at Beck SS #2 during the construction phase for the upgrade but is not expected to impact external customers. Also, customers on the existing 115kV D3A south of Allanburg TS will require planned outages as the new 115kV D3A will be transferred onto a temporary supply until the new multi-circuit towers are built and energized.

These outages will be managed and coordinated with the affected customers.

5.0 CONCLUSION

This report concludes that the proposed work will not have any adverse effect on Hydro One transmission customers in the electrical vicinity. The local customer is advised to review the short circuit results to ensure that their equipment ratings are adequate for the fault current level.

REGIONAL AND BULK PLANNING

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

Attachment 1: Regional Infrastructure Plan (July 2023)
Attachment 2: IRRP (December 2022)

These reports conclude that the construction of the Project is the most feasible and cost-effective option that alleviates the supply capacity need in the area and maintains system reliability, consistent with the IESO's evidence in support of need provided in **Exhibit B, Tab 3, Schedule 1, Attachment 1**.

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NIAGARA

REGIONAL INFRASTRUCTURE PLAN

July 12, 2023

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Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Niagara Technical Working Group

DISCLAIMER

This Regional Infrastructure Plan (RIP) Report 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 NIAGARA REGION.

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

- Alectra Utilities Corporation ("Alectra")
- Canadian Niagara Power Inc. ("CNP")
- Grimsby Power Inc. ("Grimsby Power")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator ("IESO")
- Niagara-on-the-Lake Hydro Inc. ("NOTL")
- Niagara Peninsula Energy Inc. ("NPEI")
- Welland Hydro Electric System Corp. ("Welland Hydro")

This RIP is the final phase of the second cycle of the Niagara Region regional planning (RP) process and it follows the completion of the Niagara Region Integrated Regional Resource Plan ("IRRP") [1] in December 2022; and the Niagara Region Needs Assessment ("NA") [2] and Scoping Assessment ("SA") in May 2021 and August 2021, respectively. This RIP provides a consolidated summary of needs and recommended plans for the Niagara Region over a 10-year planning horizon (2023-2032) based on available information. The load forecast for the 2033-2042 period is provided to show the longer-term needs and trend. All needs for this long-term horizon will be covered and confirmed in future regional planning cycles.

The first cycle of Regional Planning process was completed in March 2017 with the publication of the Niagara Region RIP [3], which provided a description of needs and recommendations of preferred wires plans to address near-term needs. Since the previous planning cycle, the following projects have been completed:

- Decew Falls SS (2017) – Five (5) 115kV breakers were replaced with sulfur hexafluoride (SF_6) equivalent breakers to improve supply reliability.

- Q4N Line Section Upgrade (2019) – Line section of 115kV Q4N circuit between Beck SS #1 x Portal Junction section (egress out from the generation station) was upgraded to meet load supply needs.

- A6C Line Section Refurbishment (2020) –115kV A6C circuit line conductor between Crowland TS and Port Colborne TS was replaced. The conductor needed replacement due to its asset condition.

- Stanley TS (2022) – The existing 40/53/67 MVA, 115/13.8 kV transformer T2 was replaced with a 45/60/75 MVA unit. This transformer needed replacement due to asset condition. Some 13.8kV switchyard components and protection and control equipment were also replaced due to asset condition.

- Port Colborne TS (2022) – The 28/37/47 MVA, 115/27.6 kV transformers T61 and T62 were replaced with 50/66.7/83.3 MVA units. These transformers needed replacement due to asset condition. The 27.6kV switchyard components and protection and control equipment were also replaced due to asset condition to improve the reliability of supply.

The recommended major infrastructure investments including assets replacements in the Niagara Region over the near and medium-term (2023-2032) period are given in Table 1 on the next page, along with their planned in-service date and budgetary estimate for planning purposes.

The Niagara Region TWG recommends that:

- Hydro One and LDCs continue with the implementation of infrastructure investments listed in Table 1 while keeping the TWG apprised of project status;
- All the other identified needs/options are to be further reviewed by the TWG in the next regional planning cycle.

The next regional planning cycle for the Niagara Region must be triggered within five years, beginning with the Needs Assessment ("NA") phase. It is expected that the next NA will be initiated in 2026. However, the next regional planning cycle can be started earlier if required to address any new emerging needs.

Table 0-1 Niagara Region - Recommended Plans over the 2023-2032 Study Period

No.	Investments	I/S Date	Cost[1]
A	**Increase Capacity**		
1	230 kV circuit Q28A – Uprate circuit between Beck 2 SS and Abitibi Jct.	TBD	$3M
2	Lincoln Area: Build new 230/27.6 kV, 50/83 MVA transformer station	2026	$45M
4	Crowland TS: Convert station to 230 kV with new 230/27.6 kV, 75/125 MVA transformer station and build a new 18 km of double circuit line from Abitibi Jct to Crowland TS	2027	$128M
5	Murray TS: Uprate T11/T12 75 MVA transformers with new 100MVA units	2027	$41M
6	Carlton TS: Transfer excess load to Bunting TS	2029	$5M
B	**Asset Replacement**		
1	Thorold TS: Replace Transformer T1	2024	$43M
2	Glendale TS: Replace Transformers T1 and T2	2027	$55M
3	Carlton TS: Replace LV Switchgear	2027	$55M
4	Bunting TS: Replace existing Transformers T1 and T2	2029	$45M
5	Murray TS: Replace Transformers T13 and T14	2031	$27M
6	Vansickle TS: Replace LV Switchgear	2032	$14M
7	Allanburg TS: Replace Transformer T3	2032	$20M
8	115kV Line D1A/D3A: Refurbish line section between Gibson Jct and Thorold TS	2024	$4M
9	115kV Line Q2AH: Refurbish line section between Rosedene Jct. and St. Anns Jct.	2025	$10M

[1] These costs are budgetary estimates for planning purposes only.

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1 INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Niagara Region 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:

- Alectra Utilities Corporation ("Alectra")
- Canadian Niagara Power Inc. ("CNP")
- Grimsby Power Inc. ("Grimsby Power")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator ("IESO")
- Niagara-on-the-Lake Hydro Inc. ("NOTL")
- Niagara Peninsula Energy Inc. ("NPEI")
- Welland Hydro Electric System Corp. ("Welland Hydro")

The Niagara Region includes the Regional Municipality of Niagara as shown in Figure 1-1. It includes the Cities of Niagara Falls, Port Colborne, St. Catharines, Thorold and Welland, the Towns of Fort Erie, Grimsby, Lincoln, Niagara-on-the-Lake and Pelham and the Townships of Wainfleet and West Lincoln.

Electrical supply to the Niagara region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck Generating Station (GS) #1, Sir Adam Beck GS #2, Decew Falls GS, Thorold GS and the 230kV/115kV autotransformers at Allanburg TS. Bulk supply is provided through the 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) connecting the Sir Adam Beck #2 Switching Station (SS) to stations in the Hamilton/Burlington area. The summer 2022 non-coincident peak load of the Region was about 977 MW.

Figure 1-1: Niagara Region Map

1.1 Scope and Objectives

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

- 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 needs;
- Provide the status of wires planning currently underway or completed for specific 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 reviews factors such as the load forecast, 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 (2023-2032) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan);
- Identification of any new needs over the 2023-2032 period and wires plans to address these needs based on new and/or updated information;
- Consideration of long-term needs 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 region;
- 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 and identifies the needs;
- Section 7 discusses the needs and provides the alternatives and 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 [1] ("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) determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and a Local Plan ("LP") is developed to address them. These needs are local in nature and can be best addressed by a straightforward wires solution.

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 was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

[1] also referred to as Needs Screening

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 in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves confirmation of previously identified needs; 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 of this stage is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report can be referenced in 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, plan 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.

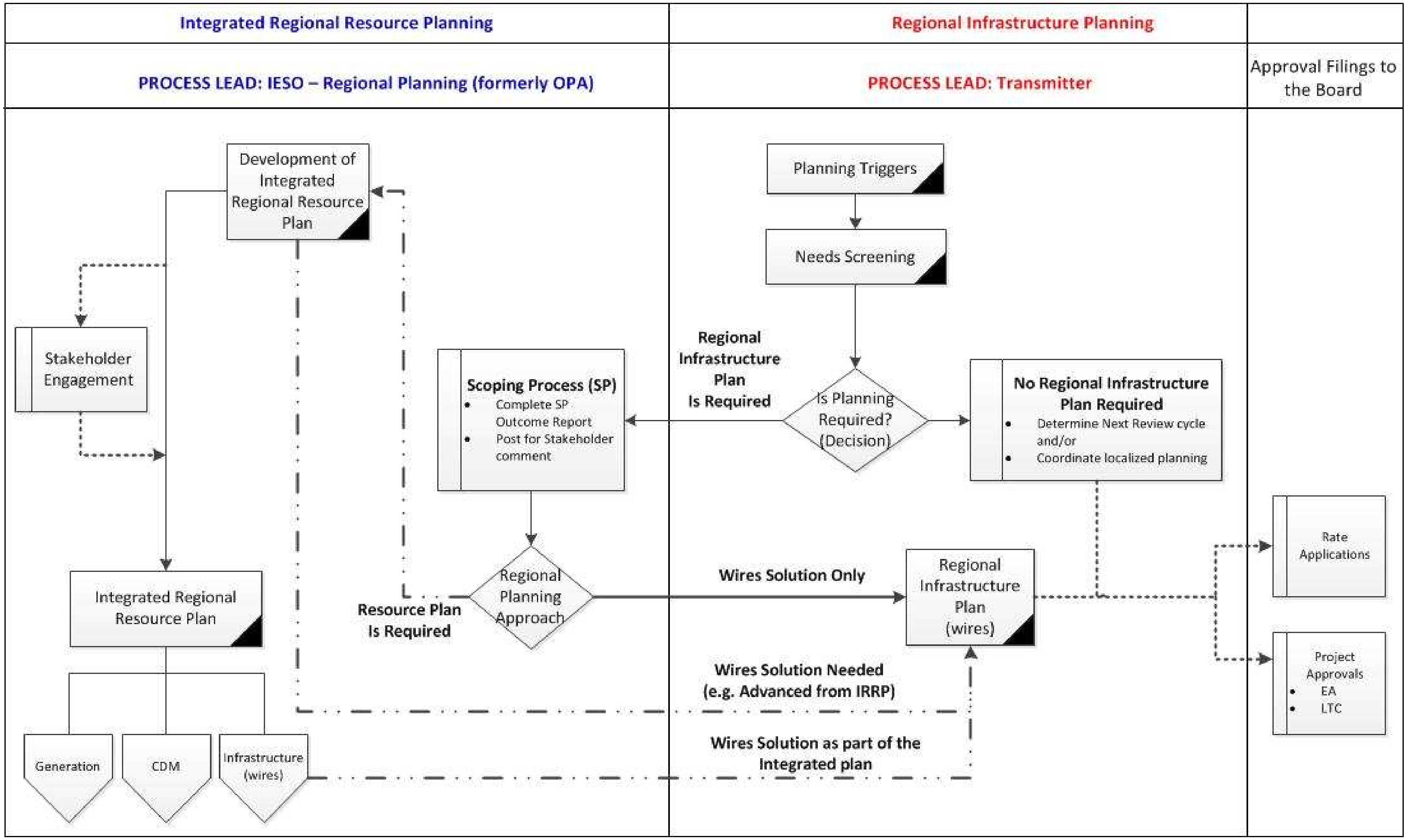

Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see

Figure 2-2) as follows:

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 Working Group 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.
    - Existing area network and capabilities including any bulk system power flow assumptions.
    - Other data and assumptions as applicable such as asset conditions, 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 to come up with 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.

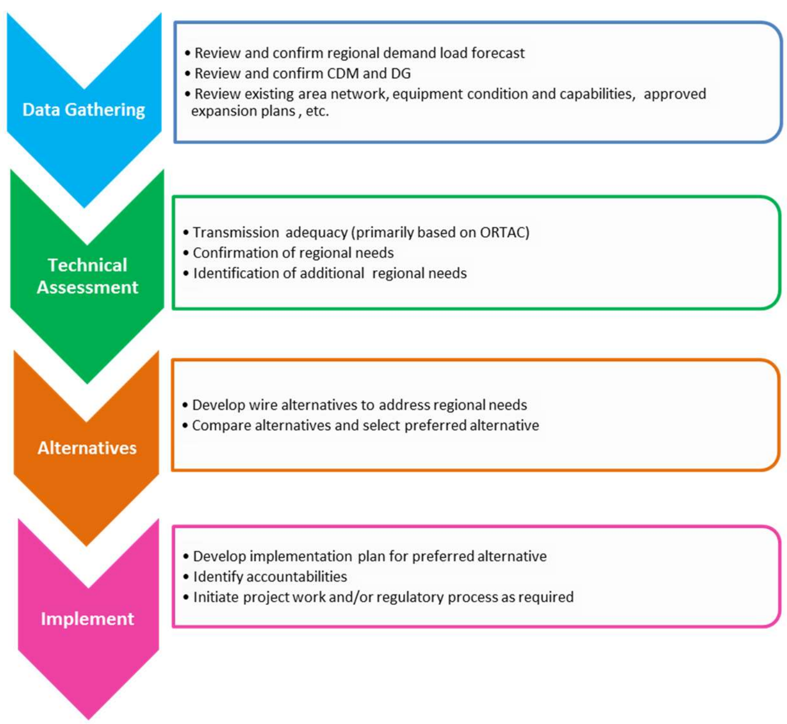

Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE NIAGARA REGION COVERS THE REGIONAL MUNICIPALITY OF NIAGARA AND INCLUDES THE CITIES OF NIAGARA FALLS, PORT COLBORNE, ST. CATHARINES, THOROLD AND WELLAND, THE TOWNS OF FORT ERIE, GRIMSBY, LINCOLN, NIAGARA-ON-THE-LAKE AND PELHAM AND THE TOWNSHIPS OF WAINFLEET AND WEST LINCOLN.

The Local Distribution Companies in the Niagara Region are Alectra Utilities Corporation, Canadian Niagara Power Inc., Grimsby Power Inc., Hydro One Networks Inc. (Distribution), Niagara-on-the-Lake (NOTL) Hydro Inc., Niagara Peninsula Energy Inc., and Welland Hydro Electric System Corp. A listing of the LDCs along with the associated supply stations is given in Appendix C. The high-voltage system in this Region also provides supply to number of direct transmission-connected customers transformer stations.

Electrical supply to the Niagara region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck GS #1, Sir Adam Beck GS #2, Decew Falls GS, Thorold GS and the 230kV/115kV autotransformers at Allanburg TS. The 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) from Sir Adam Beck #2 SS connect this region to Hamilton/Burlington. The power is distributed through thirteen (13) HONI and six (6) LDC owned step-down transformer stations (please see Appendix B for a complete list. The distribution system in this Region is at two voltage levels, 27.6 kV and 13.8 kV. An electrical single line diagram for the Niagara Region transmission facilities is shown in Figure 3-1. The circuits and stations are provided in Table 3-1.

Table 3-1: Station and Circuits in the Niagara Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
Q3N, Q4N, Q11S, Q12S, A36N, A37N, A6C, A7C, D9HS, D10S, D1A, D3A, Q2AH	Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M, Q10P	Allanburg TS*, Beamsville TS, Bunting TS, Carlton TS, Crowland TS, Dunnville TS, Glendale TS, Kalar MTS, Niagara Murray TS, Niagara West MTS, NOTL York MTS, NOTL #2 MTS, Port Colborne TS, Stanley TS, Thorold TS, Vansickle TS, Vineland DS, CNPI Station #17 MTS, CNPI Station #18 MTS	Sir Adam Beck GS #1, Sir Adam Beck GS #2, Sir Adam Beck PGS, Thorold CGS, Decew Falls GS

*Station with Autotransformers installed

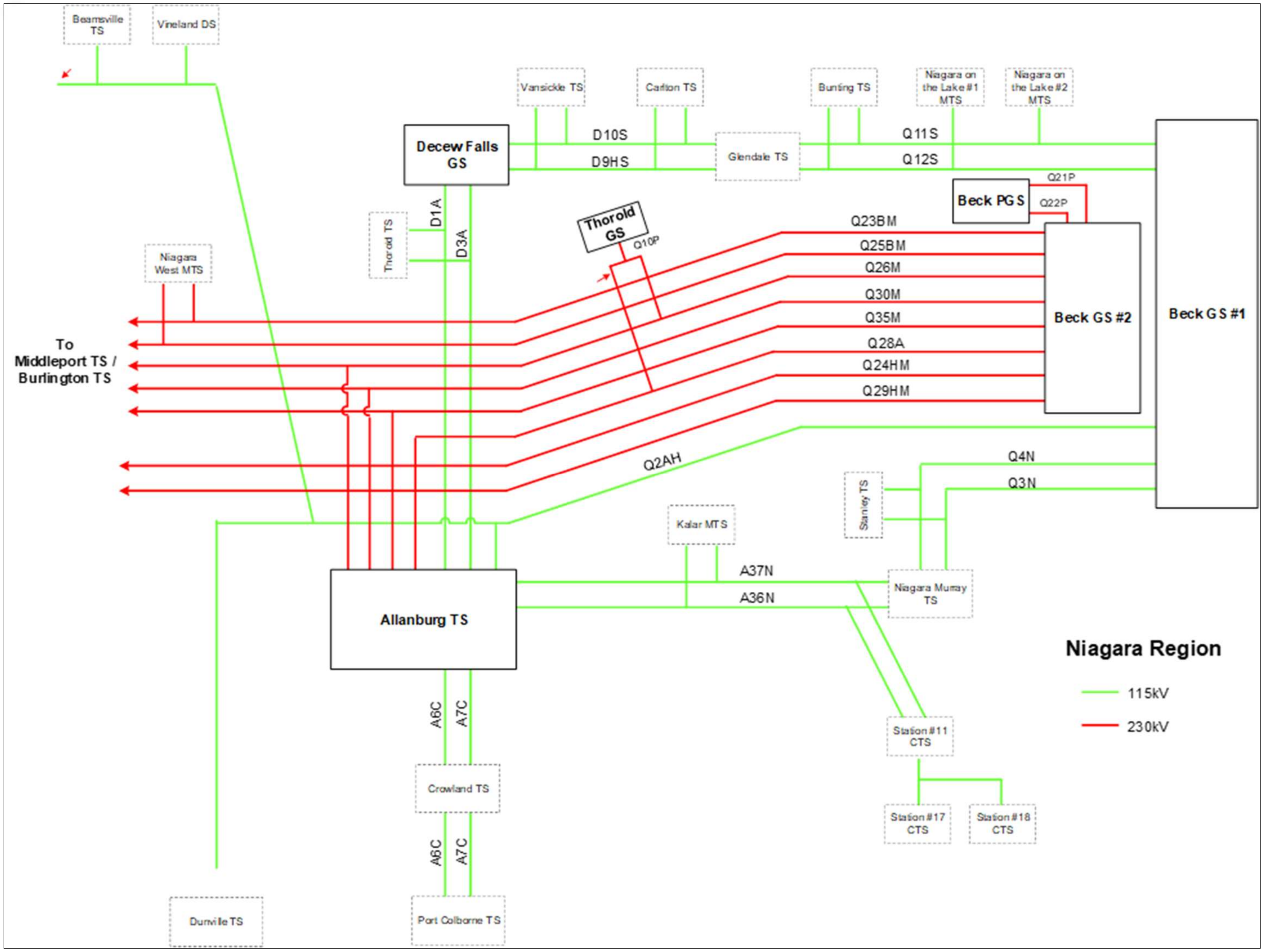

Figure 3-1: Niagara Region Single Line Diagram

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

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

A summary and brief description of the major projects completed and/or currently underway over the last ten years is provided below:

Projects Completed

- Decew Falls SS (2017) – Existing five (5) 115kV breakers were replaced with sulfur hexafluoride (SF6) equivalent breakers to improve supply reliability.

- Q4N Line Section Upgrade (2019) – Line section of 115kV Q4N circuit between Beck SS #1 x Portal Junction section (egress out from the generation station) was upgraded to meet load supply needs.

- A6C Line Section Refurbishment (2020) –115kV A6C circuit line conductor between Crowland TS and Port Colborne TS was replaced. The conductor needed replacement due to its asset condition.

- Stanley TS (2022) – Existing 40/53/67 MVA T2 transformer was replaced with a 45/60/75 MVA unit. This transformer needed replacement due to asset condition. Work at 13.8kV switchyard components and protection and control equipment were also replaced due to asset condition.

- Port Colborne TS (2022) – Existing T61 and T62 28/37/47 MVA transformers was replaced with 50/66.7/83.3 MVA units. These transformers needed replacement due to asset condition. The 27.6kV switchyard components and protection and control equipment were also replaced due to asset condition to improve the reliability of supply.

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

A detailed load forecast for the Niagara region was developed as part of the area IRRP study. The TWG participants, including representatives from LDC's, IESO and Hydro One provided information and input for the IRRP Load forecast.

The IRRP forecast used in this RIP study includes minor increases at a few stations as per the LDCs[2]. Also included is a LDC connected industrial customer with curtailable load under specific outage conditions.

The load in the Niagara Region is expected to grow at an average rate of approximately 2.3% annually from 2023 to 2032. However, a major portion of this load increase is due to industrial customers. The growth rate for the LDCs, not accounting for the industrial customers, is about 1.3%. Longer term growth rate between 2033 to 2042 for all customers is forecast to be about 0.9%.

Figure 5-1 shows the Niagara region extreme summer weather net forecast from 2023-2042. The forecast shown is the regional non-coincident forecast and shows the load for all Niagara customers as well as the load for all the LDCs. The regional non-coincident peak load is forecast to increase from approximately 1092MW in 2023 to about 1505MW in 2042.

[2] Loading at Crowland TS adjusted as per new forecast from Welland Hydro. Loading at NOTL #2 MTS and NOTL York MTS adjusted as per new forecast from NOTL Hydro.

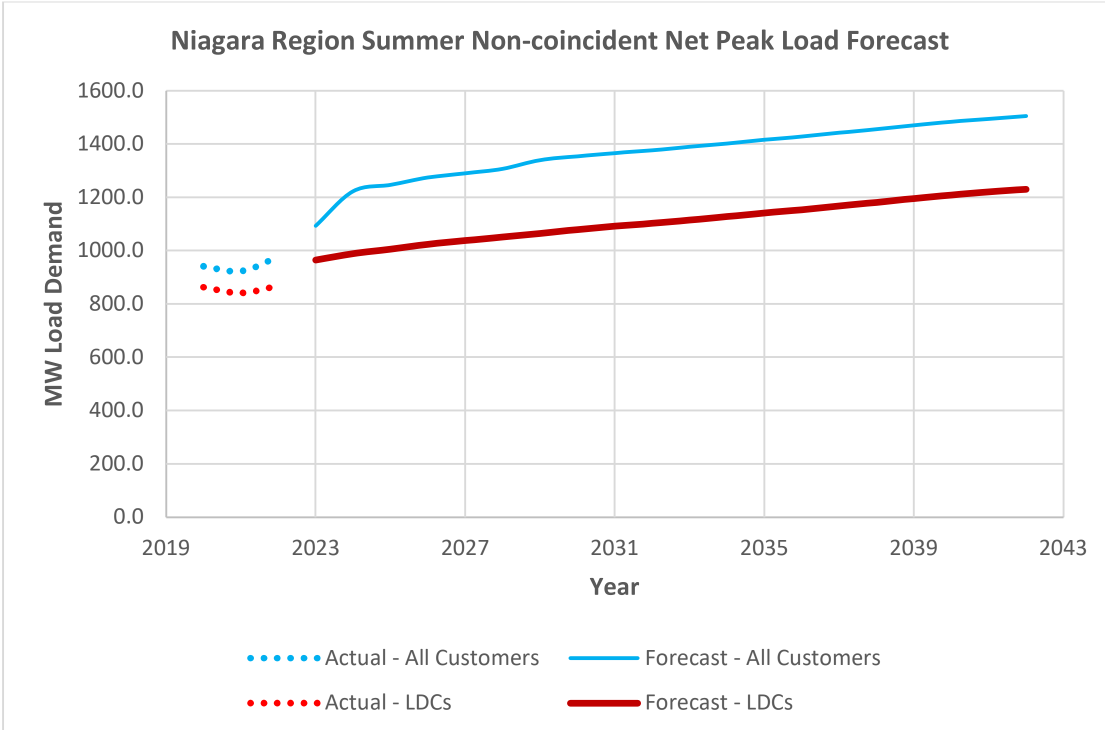

Figure 5-1: Niagara Region Summer Non-Coincident Weather Corrected Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2023-2032. However, a longer term forecast up to 2042 is provided to identify long-term needs and align with the Niagara region IRRP.
- LDCs reconfirmed load forecasts up to 2041. The additional year of forecast to 2042 was extrapolated to complete the 20 year period.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings for this region. The assessment is therefore 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, where the power factor used for the load stations are from the IRRP Appendix G.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Radial line adequacy is assessed using non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

6 SYSTEM ADEQUACY AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE NIAGARA REGION AND LISTS FACILITIES REQUIRING REINFORCEMENT OVER THE 2023-2032 PERIOD.

In the current regional planning cycle, the three regional assessments were completed for the Niagara Region and their findings were used as inputs to this RIP report. These assessments are:

- Niagara Region Needs Assessment (NA) Report, May 2021.
- Niagara Region Scoping Assessment (SA) Report, August 2021
- Niagara Region Integrated Regional Resource Plan (IRRP), December 2022 and Appendices, February 2023

The NA and IRRP reports identified several needs because of the forecasted load demand and condition of major high voltage transmission assets. This section reviews the adequacy of the transmission lines and stations in the Niagara Region based on the updated regional load forecast provided in Appendix C. Sections 6.1 to 6.3 present the results of this review. Asset replacement needs identified in the previous NA report are discussed in Section 6.4 of this report. Load security and load restoration needs are discussed in Section 6.5.

6.1 230 kV and 115kV Transmission Circuits

All 230 kV transmission circuits in the Niagara Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the Ontario's transmission system, carry power from the Niagara River Generation to the rest of Ontario and are part of the interconnection path that connects Ontario to neighboring New York State at the Beck 2 SS. The 230 kV circuits Q26M, Q28A, Q30M and Q35M circuits also supply the 230/115 kV autotransformer station at Allanburg TS to serve local area stations within the region. The power flow on these circuits depend on the bulk system transfers as well as the local area loads.

Over the study period 2023-2032 the RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Niagara Region. The NA and IRRP studies had previously indicated that the following Transmission lines require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 6-1 below. The need date defines the time when the peak load forecast exceeds the most limiting summer Limited Time Ratings. Mitigation measures are discussed in Section 7.1.

Table 6-1: Niagara Region - Lines Sections Exceeding Ratings

No.	Voltage	Line	Section	Contingency	Line Rating MW	Need Date
1	230kV	Q28A	Beck 2 x Abitibi Jct.	N-2[1]	386	2024[2]
2	115kV	A6C/A7C	Allanburg TS x Crowland TS	N-1	214	2029

1. Loss of double circuit line Q26M/Q35M
2. Need date dependent on customer forecast load increase

6.2 230/115kV Transformation Facilities

Almost ninety percent of the Niagara Region load is supplied from the 115 kV transmission system. This power is supplied to the 115kV system through the four 230/115 kV autotransformers at Allanburg TS together with 115kV generation at Sir Adam Beck #1 GS and Decew Falls GS.

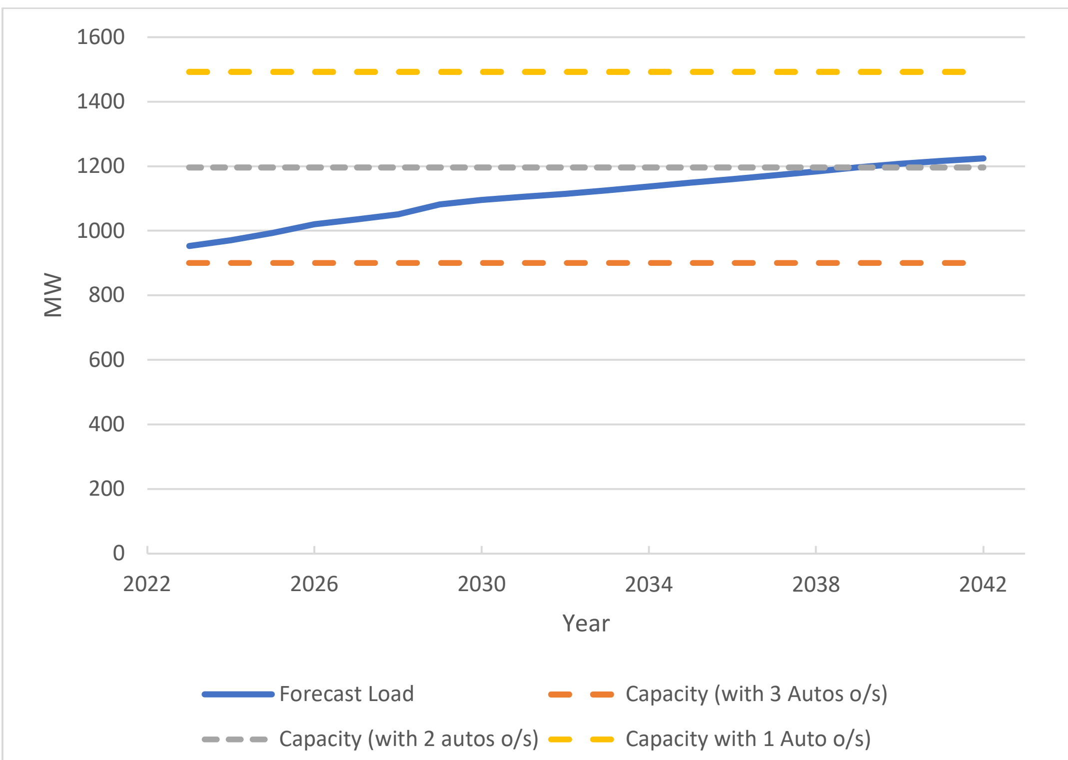

Figure 6-1: Niagara Region – 115kV Area Load and Supply Capacity

The forecast loading on the 115kV system is shown in Figure 6-1, together with the supply capacity with one, two and three autotransformers out of service at Allanburg TS and the local 115kV generation at 605MW[3]. There is adequate supply capacity in the region for the loss of up to 2 of the 4 autotransformers beyond the 2023-2032 RIP study period. However, since the autotransformers are connected to the 230kV circuits directly – loss of up to three autos can occur under an outage condition followed by a double circuit line outage – resulting in load exceeding supply capacity (N-1-2 contingency). Mitigation measures to address this issue are described in Section 7.2.

6.3 Step Down Transformation Facilities

There are a total of twenty-six (26) step-down transformer stations supplying power to customers in the Niagara Region as listed in Table 6-2. These include thirteen stations owned by Hydro One, six by area LDCs and seven (7) by direct industrial customers. The stations' summer peak load forecast is given in Appendix D Table D-1.

Table 6-2: Niagara Region - Step-Down Transformer Stations

Allanburg TS	CNPI Station #18 MTS	Murray TS	Stanley TS
Beamsville TS	Crowland TS	Niagara West MTS	Thorold TS
Bunting TS	Dunnville TS	NOTL #2 MTS	Vansickle TS
Carlton TS	Glendale TS	NOTL York MTS	Vineland DS
CNPI Station #17 MTS	Kalar MTS	Port Colborne TS	CTS #1
CTS #2	CTS #3	CTS #4	CTS #5
CTS #6	CTS #7		

Over the study period 2023-2032 the RIP reviewed the capacity of all the 230kV and 115kV transformer stations within the Niagara 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 6-3.

[3] Beck GS #1 is assumed at 490MW and Decew Falls GS at 115 MW.

The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer) Limited Time Ratings. Mitigation measures to address this issue are described in Section 7.3.

Table 6-3: Niagara Region Station Capacity Needs in the Study Period

No.	Station Name	Capacity (MVA)	2023 Loading (MW)	Station 10- day LTR (MW)	Need Date
1	Beamsville TS	25/42	64.2	59.0	2023
2	Murray TS T11/T12	45/75	77.7	73.2	2023
3	Niagara West MTS	40/67	54.6	66.0	2024
4	Crowland TS	50/83	100.9	101.7	2024
5	Carlton TS	45/75	89.2	95.4	2029

6.4 Asset Replacement Needs for Major High Voltage (HV) Transmission Equipment

Several Hydro One facilities in the Niagara Region will require asset renewal work over the 2023-2032 study period. These needs are determined by asset condition based on a range of considerations such as equipment deterioration, technical obsolescence due to outdated design, lack of spare parts availability or manufacturer support, and/or potential health and safety hazards.

Asset replacement work is planned over the study period at area transformer stations and lines listed in Table 6-4. The options and preferred solutions to address these needs are discussed further in Section 7.4 of the report.

Table 6-4: Niagara Region - Planned Replacement Work

No.	Station	Planned I/S Date
A - Station Work		
1	Thorold TS	2024
2	Glendale TS	2027
3	Murray TS T11/T12	2027
4	Carlton TS	2027
5	Crowland TS	2027
6	Bunting TS	2029
7	Murray TS T13/T14	2031
8	Vansickle TS	2032
9	Allanburg TS	2032
B – Lines Work		
1	115kV D1A/D3A	2024
2	115kV Q2AH	2025

6.5 Load Security and Load Restoration Needs

Load security and load restoration needs were reviewed as part of the current study and one load security need has been identified for the region. The ORTAC requires that not more than 150MW of load may be interrupted by planned load curtailment or load rejection and the Allanburg Load Rejection scheme does not meet the criteria.

6.5.1 A6C/A7C Load Security

The loss of the 230kV double circuit line Q26M/Q28A, will result in the coincidental loss of autotransformers T1 and T2 at Allanburg TS and the separation of the 115kV A6C/A7C and D1A and A36N circuits from the Allanburg TS 115kV bus. Under this scenario the Allanburg Load Rejection scheme trips the A6C and A7C circuits to prevent loads connected to the A6C/A7C circuits from excessive voltage declines. The load on the A6C/A7C is currently about 200MW and forecast to increase to 278MW by the end of the plan period. The amount of load rejected is thus more than the permitted amount of 150 MW allowed under ORTAC. Mitigation measures to address this need are discussed in Section 7.5.

7 REGIONAL PLANS

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

The electrical infrastructure needs for the Niagara Region are summarized in Table 7-1. These needs include those previously identified in the Niagara Region NA and IRRP as well as those resulting from the adequacy assessment carried out as part of this RIP report. The details of the project/plan to address these needs are provided in Sections 7.1 through 7.5.

Table 7-1: Niagara Region – Identified Near and Medium-Term Needs

Section	Facilities	Need	Timing
Transmission Line Capacity Needs			
7.1.1	Q28A -Beck 2 TS to Abitibi Jct.	Line Capacity Exceeded	2024
7.1.2	115 kV Circuits A6C and A7C – Allanburg TS to Crowland TS	Line Capacity Exceeded	2029
230/115 kV Transformation Capacity/115kV Supply Area Capacity			
7.2	Allanburg TS	Loading exceeds Capacity at Allanburg TS	2023
Station Capacity			
7.3.1	Beamsville TS and Niagara West MTS	Forecast load exceeds normal supply capacity	2023
7.3.2	Crowland TS	Forecast load exceed normal supply capacity	2024
7.3.3	Murray TS and Kalar TS	Forecast load exceed normal supply capacity	2028
7.3.4	Carlton TS	Forecast load exceed normal supply capacity	2029
Asset Replacement			
7.4	Thorold TS	Transformer T1 replacement	2024
7.4	Carlton TS	LV Switchyard refurbishment	2027
7.4	Glendale TS	Transformers T1 and T2 replacement	2027
7.4	Crowland TS	Transformer T5 and T6 replacement	2027
7.4	Murray TS	Transformers T11 and T12 replacement	2027
7.4	Bunting TS	Transformers T1 and T2 replacement	2029
7.4	Murray TS	Transformers T13 and T14 replacement	2031
7.4	Vansickle TS	LV Switchyard refurbishment	2032
7.4	Allanburg TS	Transformer T3 replacement	2032
7.4	115kV Line D1A/D3A	Gibson Jct. x Thorold TS	2024
7.4	115kV Line Q2AH	Rosedene Jct. x St. Anns Jct.	2025
Load Security			
7.5	115kV A6C/A7C Load Security	Forecast exceeds ORTAC load rejection Criteria	2023

7.1 Transmission Line Capacity

This section describes work required to address the transmission line capacity needs associated with the 230kV circuit Q28A and 115kV circuits A6C and A7C as described in Section 6.1.

7.1.1 230kV circuit Q28A – Beck #2 TS x Abitibi Junction

7.1.1.1 Introduction

The 230kV circuit Q28A is part of the eight transmission circuits egressing from Beck #2 GS and connects to Allanburg TS. The planning forecast based on new customer load indicates that the loading will exceed the circuit 980A rating by summer 2024 for a loss of the double circuit line Q26M/Q35M.

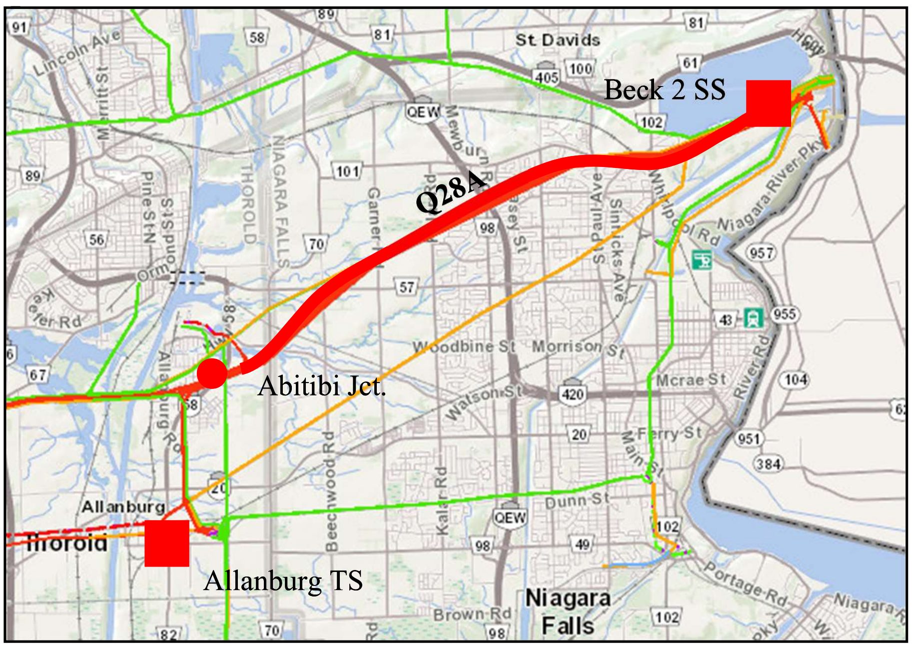

Figure 7-1: Uprate Q28A Circuit

7.1.1.2 Alternatives and Recommendation

The following alternatives were considered to address the 230kV circuit Q28A capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative is not viable as it does not address meeting the area customers' load requirements. It is therefore not considered further.
- **Alternative 2 – Uprate 230kV Q28A Circuit:** This alternative considers uprating the conductor by tensioning the conductors to reduce the line sag and allow the line conductor to operate at a higher temperature. This will increase the circuit rating from 980A to 1310A. The estimated cost of the work is about $3M.

The TWG recommends Alternative 2 as the preferred and cost-effective alternative for increasing the capacity of the line. Hydro One has advised the customer of the proposed work and will initiate the work once confirmed by the customer.

7.1.2 115 kV Circuits A6C and A7C – Allanburg TS to Crowland TS

7.1.2.1 Introduction

The 115 kV double circuit line A6C/A7C supplies Crowland TS and Port Colborne TS along with several directly connected transmission customers as shown in Figure 7-2. The load connected on this line is forecast to exceed the line capacity by summer 2029 as shown in Table 7-2.

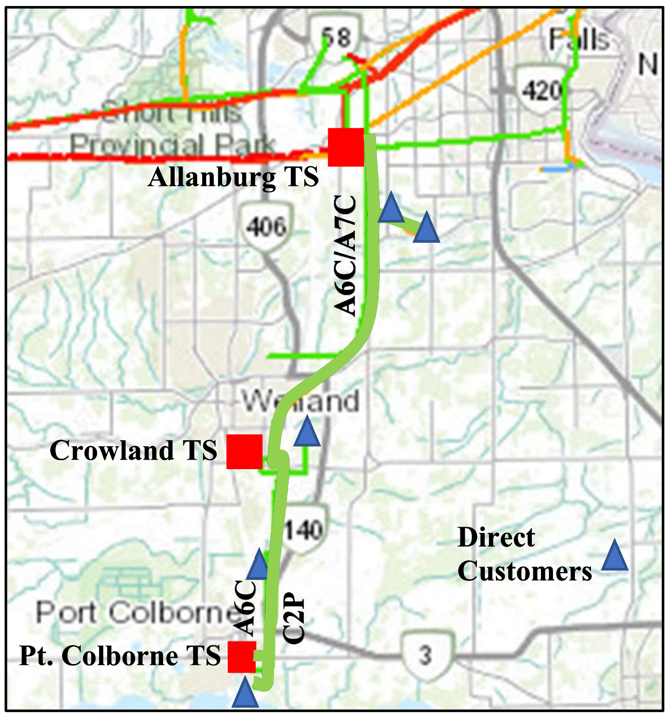

Figure 7-2: Map of 115kV A6C/A7C Circuits

Table 7-2: 115kV circuit A6C/A7C -Connected Loads

Load	Circuit Limit	Act.[1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
A6C/A7C[2]	213.9[3]	169.5	174.0	182.4	191.6	202.2	206.8	211.6	232.7	234.9	236.8	236.9	246.1	2029
Crowland TS		93.6	100.9	108.8	110.6	112.6	114.1	115.9	117.6	119.6	121.3	121.2	128.5	---
A6C/A7C post Crowland[4]			-	-	-	-	92.7	95.7	115.1	115.3	115.5	115.7	117.6	---

1. Actual summer load adjusted for extreme weather
2. Loading excludes Allanburg TS DESN
3. Rating of A6C/A7C circuit between Allanburg TS DESN and Crowland TS

4. After Crowland TS conversion to 230KV as per Section 7.3.2 in 2027

7.1.2.2 Alternatives and Recommendation

The following alternatives were considered to address the overloading issue on the 115kV line A6C/A7C line:

- **Alternative 1 – Maintain Status Quo:** This alternative is not viable as it does not address meeting the area customers' load requirements. It is therefore not considered further.
- **Alternative 2 – Uprate the A6C and A7C Circuits:** This alternative considers reconductoring the A6C/A7C line between Allanburg TS and Crowland TS (~ 14.5 km) using a higher rated conductor. This will increase the circuit rating from 214 MW to about 280 MW. The estimated cost of the work is $23M.
- **Alternative 3 – Reduce Loading on A6C/A7C:** This alternative reduces loading on circuits A6C and A7C by rebuilding Crowland TS[4] as a 230/27.6 kV station supplied from and supplying it from a new 230kV circuit line.

The TWG recommends Alternative 3 as the preferred and cost-effective alternative addressing the overloading issue on the A6C/A7C line. Transferring of Crowland TS to a 230 kV supply also addresses multiple other issues; reduces load on the Allanburg TS autotransformers (See Section 7.2.2), allows increase capacity at Crowland TS (see Section 7.3.2), and reduces the severity of the load security issue (Section 7.5).

7.2 115kV Supply Area Capacity

7.2.1 Introduction

As shown in Section 6.2, the loads on the Niagara Region 115kV system exceeds the 115 kV system supply capability under certain contingency conditions which result in three out of the four autotransformers being out of service at Allanburg TS. Specifically, this occurs under a 230kV outage condition followed by a double 230kV circuit line outage (N-1-2 contingency).

7.2.2 Alternatives and Recommendation

The following alternatives were considered to address the 115 kV supply capacity:

- **Alternative 1 – Maintain Status Quo:** This alternative is not viable as it does not address meeting the area customers' load requirements. It is therefore not considered further.

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[4] Crowland TS needs to be refurbished and will be rebuilt. Please refer to Section 7.3.2 and 7.4 for more details.

- **Alternative 2 – Modify Existing Load Rejection Scheme for 115kV Subsystem:** This alternative modifies the Allanburg load rejection scheme to include rejection of up to 150MW of load whenever three autotransformers are out. The estimated cost of this alternative is about $8M.
- **Alternative 3 – New 230kV Switchyard at Allanburg TS:** The work required in this alternative is to build a new 230kV switchyard to eliminate the N-1-2 contingency at Allanburg TS (loss of three autotransformers contingency) to supply more power to the 115kV network. The work required would consist of four new 230kV bus diameters, each accommodate an autotransformer to eliminate any coincidental loss of the autotransformers. This work has an estimated cost of $253M.
- **Alternative 4 – Reduce load on 115kV system by introducing 230kV Supply to the Welland Area -** This alternative would transfer Crowland TS to 230kV supply by building a 18km double circuit 230kV transmission line from Q24HM/Q29HM to connect to a new 230/27.6kV transformer station at the Crowland TS site. The new TS will replace the existing station that requires replacement. This work has an estimated cost of $128M.

The TWG recommends Alternative 4 as the most cost effective and preferred alternative. Besides addressing the 115kV supply capacity needs, this alternative also addresses; the A6C/A7C overloading issue (Section 7.1.2); the Crowland TS capacity needs (Section 7.3.2); the Crowland TS asset renewal needs (Section 7.4); and reduces the severity of the A6C/A7C load security issue (Section 7.5). The work is planned to be in service by summer 2027.

7.3 Station Capacity Needs

This section describes the work required to address the station capacity needs identified in Section 6.3.

7.3.1 Beamsville TS, Vineland DS, Niagara West MTS – 115kV Lincoln Area

7.3.1.1 Introduction

Beamsville TS and Vineland DS are 115/27.6kV stations and Niagara West MTS is a 230/27.6kV station which supplies the towns of Grimsby, West Lincoln, and Lincoln. The area is experiencing load growth where the summer weather extreme demand forecast will exceed the area normal supply capacity.

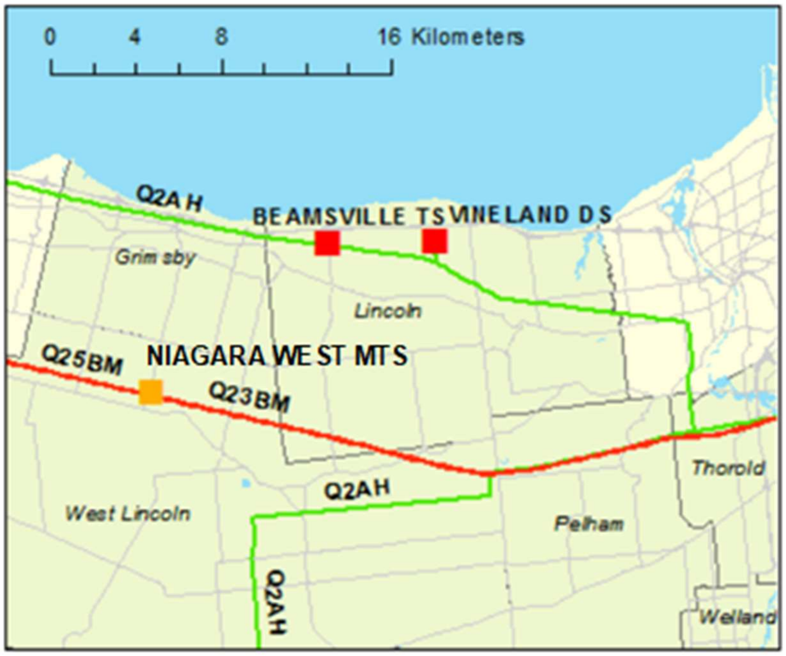

Figure 7-3: Map of 115kV Lincoln Area

Beamsville TS presently has 115kV/27.6kV 42MVA transformers (T3/T4) with a summer LTR of 59.0MW. This station has operated at or slightly over the LTR over the past few years.

Table 7-3 shows the forecast for the three area stations. The forecast shows that the combined capacity of the three stations would be exceeded by summer 2024. The TWG agrees that a solution is required to address the upcoming supply capacity needs.

Table 7-3: 115kV Lincoln Area Stations Load Forecast

Station	LTR MW	Act. [1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Beamsville	59.0	63.1	77.2	79.2	80.5	81.4	82.1	82.9	83.7	84.6	85.6	86.5	101.9	---
Niagara West MTS[2]	63.4	41.6	49.0	56.8	57.6	58.2	58.9	60.3	61.7	63.2	64.7	66.2	84.3	---
Vineland DS	26.4	20.5	20.7	20.9	21.1	21.3	21.6	22.5	23.5	24.5	24.7	25.0	27.6	---
Total	148.8	125.3	147.0	156.9	159.2	161.0	162.5	165.7	168.9	172.3	175.0	177.7	213.8	2024

1. Actual summer load adjusted for extreme weather

7.3.1.2 Alternatives and Recommendation

The following alternatives were considered to address the area capacity need:

- **Alternative 1 – Maintain Status Quo:** This solution is not recommended as it does not address the supply capacity needed in the area. This solution will also prevent load growth in this area.

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- **Alternative 2 – Load Transfer to Neighbouring Stations:** This solution is not viable as there is no nearby station where the load can be transferred.
- **Alternative 3 – Replace Beamsville and Niagara West transformers:** Replace existing Beamsville TS T3/T4 transformers and Niagara West MTS T1/T2 with larger 50/83MVA units, providing total additional capacity of 100 MW at both stations to address the existing and future load demand. Additional feeder positions will be required at both stations to utilize the additional capacity. The cost of this work is estimated to be about $48M.
- **Alternative 4 – Build new 230/27.6kV DESN station in Local Area:** This alternative would build a new 230/27.6kV DESN station to supply the increased load demand forecast required in the local area. The new station would be supplied by the double circuit 230kV transmission line Q23BM/Q25BM with new 50/83MVA transformers. The new station will provide about 102 MW of new capacity. The estimated cost of this alternative is about $45M.

The TWG recommends proceeding with Alternative 4. This alternative provides a robust transmission solution to meeting the area LDCs demand forecast and will also allow for future load growth beyond the study period on the 230kV system. This solution will also provide better reliability for future loads as the new station will have dual incoming transmission supplies into station instead of being on a single supply like Beamsville TS. Loads will be managed by the respective LDCs between 2024 and 2027 when the new facility is expected to go into service.

Hydro One will work with all the respective parties to find a suitable location to meet the load. Possible locations could be an expansion at Niagara West MTS or a location central to Vineland DS and Beamsville TS to supply local growth (e.g., the southwest corner in the Town of Lincoln).

7.3.2 Crowland TS

7.3.2.1 Introduction

Crowland TS is a 115/27.6kV 50/83MVA transformer station located in Welland. The station load is at or near its 10-day LTR of 101.7 MW and load is forecasted[5] to increase up to 121MW by the end of 2032 as shown in Table 7-4 below. A permanent supply solution is required for the increased load growth as the current loading will surpass the station capacity in 2024.

The transformers, T5 and T6, at Crowland TS are about 55 years old and based on asset condition assessment Crowland TS has been identified for asset renewal by summer 2027.

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[5] Forecast updated from IRRP as per Welland Hydro

Figure 7-4: Map of Crowland TS

Table 7-4: Crowland TS Load Forecast

Station	LTR MW	Act.[1]	Load Forecast										Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Crowland TS	101.7	93.6	100.9	108.8	110.6	112.6	114.1	115.9	117.6	119.6	121.3	121.2	128.5	2024

1. Actual summer load adjusted for extreme weather

7.3.2.2 Alternatives and Recommendation

The following alternatives were considered to address Crowland TS capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not provide supply capacity to area customers during the study period. Under this scenario load cannot be increased at this station.
- **Alternative 2 – Rebuild existing DESN at Crowland TS and add a second DESN at Crowland TS:** Under this alternative the existing Crowland TS transformers will be replaced, and the station refurbished. A new second DESN would be built to handle the increased load. This alternative would maintain the existing 115kV loading on the Allanburg autotransformers and work will be required to address the issue. Work also would be required to address the capacity need on the A6C/A7C circuits and address the load security concern at Allanburg TS. This alternative is estimated to cost $78M for the refurbishment work and new DESN at Crowland TS. An additional $253M will be required to provide additional switching at Allanburg TS to reinforce the 115kV supply.

- **Alternative 3 – Provide a new 230kV Supply to Welland Area and convert Crowland TS to 230kV:** Under this alternative the existing Crowland TS would be replaced with a new 230/27.6 kV DESN station with 75/125 MVA transformers to supply the increased load demand. A new 18km double circuit 230kV transmission line will be constructed to supply this new transformer station from the double circuit 230 kV line Q24HM/Q29HM. This new station would allow the station LTR to increase to approximately 170 MW (summer) with 75/125MVA transformers. The estimated cost of this alternative is about $128M.

The TWG recommends Alternative 3 as it is the lowest cost alternative. It provides new area transmission and load growth opportunities. The conversion of Crowland TS to 230kV will reduce the loading on the 115kV autotransformer at Allanburg TS, alleviating the constrained supply to the 115 kV sub-system described previously. It will also remove the existing Crowland TS loads from the 115kV A6C/A7C circuits, alleviating the severity of the load security constraint at Allanburg TS. This alternative will also provide a parallel opportunity for load growth on the 115kV A6C/A7C circuits as the Crowland TS load is removed from the 115kV system.

7.3.3 Murray TS and Kalar MTS – Niagara Falls

7.3.3.1 Introduction

Murray TS and Kalar TS are two transformer stations located in Niagara Falls. Murray TS has two 115/13.8 DESNs, T11/T12 and T13/T14, with a summer LTR of 73.2MW and 79.8MW respectively. Kalar MTS has one 115/13.8 kV DESN with a summer LTR of 72.0 MW. The stations forecast loads are given in Table 7-5. Considerable new loads are expected to connect in the area. Loading on the Murray TS T11/T12 DESN is forecast to exceed its LTR by summer 2023. Loading on Kalar MTS is forecast to exceed LTR by summer 2028.

The Murray TS transformers, T11, T12, T13 and T14 are between 46 and 52 years old and have been identified for replacement due to asset condition. It is planned to replace T11 and T12 by summer 2027. This will be followed by the replacement of the T13 and T14 transformers by summer 2031.

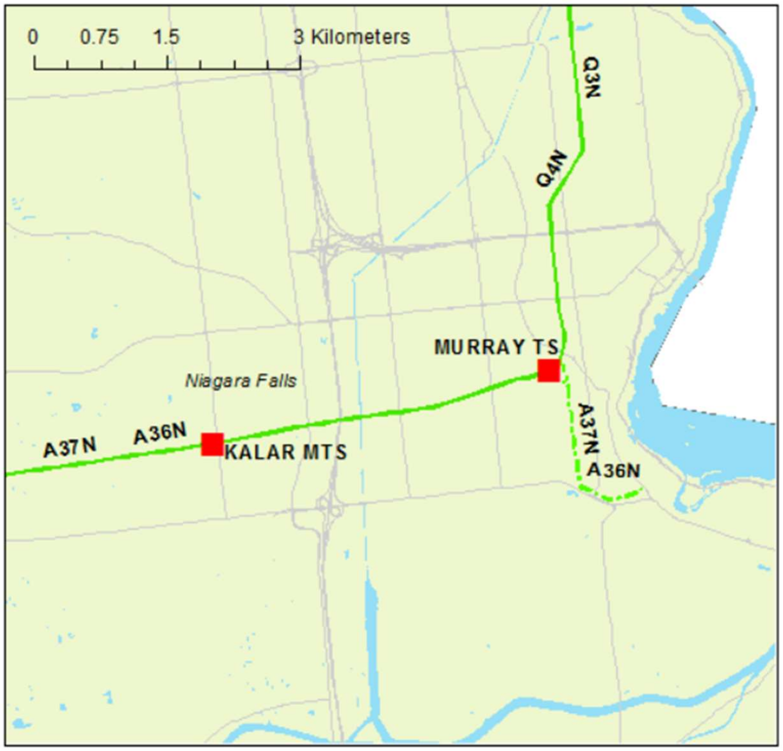

Figure 7-5: Map of Murray TS and Kalar MTS

Table 7-5: Murray TS, and Kalar MTS Load Forecast

Station	LTR MW	Act[1]	Load Forecast										Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Murray TS T11/T12	73.2	66.3	77.7	77.7	77.8	78.0	77.9	78.1	78.3	78.7	78.9	79.1	86.2	2023[2]
Murray TS T13/T14	79.8	41.7	42.0	42.2	42.4	42.6	42.9	43.1	43.3	43.5	43.8	44.0	46.6	Note[3]
Kalar MTS	72.0	46.5	46.9	47.4	54.2	60.7	64.4	65.8	67.1	68.6	68.8	69.0	75.1	2039
Total	225.0	166.3	166.6	167.3	174.4	181.3	185.2	187.0	188.7	190.8	191.5	192.1	207.9	

1. Actual summer load adjusted for extreme weather
2. Earliest replacement to happen by 2027
3. The transformers T13 and T14 will be replaced in 2031as per asset condition.

7.3.3.2 Alternatives and Recommendation

The following alternatives were considered to address the current and future capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not address the need as the near and mid-term load forecast exceeds the LTR at Murray TS T11/T12. Asset renewal needs are also not addressed.
- **Alternative 2 – Replace T11/T12 at Murray TS with 60/100MVA transformers:** This alternative would replace the T11/T12 transformers with larger 60/100MVA transformers, with an approximate

LTR of 130MW instead of the 45/60/75MVA units specified for the asset renewal project at Murray TS. This will increase supply capacity of approximately 43MW at Murray TS at an estimated incremental cost of $2M to the asset renewal upgrade cost of $39M. The earliest this work can be done is summer 2027.

- **Alternative 3 – Transfer T11/T12 load to T13/T14 at Murray TS:** This alternative would transfer load from T11/T12 to T13/T14 at a cost of $5M. The T13/T14 bus supplies a large industrial load customer with fluctuating load and customers connected to the bus would experience power quality issues.
- **Alternative 4 – Build new 115kV/13.8kV Station near Kalar MTS:** This alternative would build a new 115/13.8kV DESN station with 25/41.7MVA transformers to supply the increased load demand forecast required at Kalar MTS and Murray TS T11/T12. This new station would provide the station an LTR of 51MW (summer). The estimated cost for this alternative is expected to be $40M.

The TWG recommends Alternative 2 as the preferred alternative for addressing the capacity need as it is the most economical alternative with the ability to increase supply capacity. Alternative 3 is not recommended since is more expensive, will introduce power quality issues to the transferred load and is not acceptable to the LDC. Loading will be monitored and managed at Murray TS by the LDC and Hydro One in the interim before the additional capacity is provided in 2027. The Kalar MTS load growth will be monitored to verify if the actual summer peak loads are close to the mid-term forecast. When the actual load is approaching the forecast, the respective LDC will re-evaluate and can transfer the extra load from Kalar MTS to Murray TS.

7.3.4 Carlton TS and Bunting TS – St. Catharines

Carlton TS and Bunting TS are two transformer stations located in St. Catharines. Carlton TS has one 115/13.8 kV T1/T2 DESN with a summer LTR of 95.4 MW. Bunting TS has one 115/13.6 kV T1/T2 DESN with a summer LTR of 78.2 MW. The stations forecast loads are given in Table 7-6. Loading on Carlton TS is forecast to exceed its LTR by summer 2029. Bunting TS is adequate over the study period.

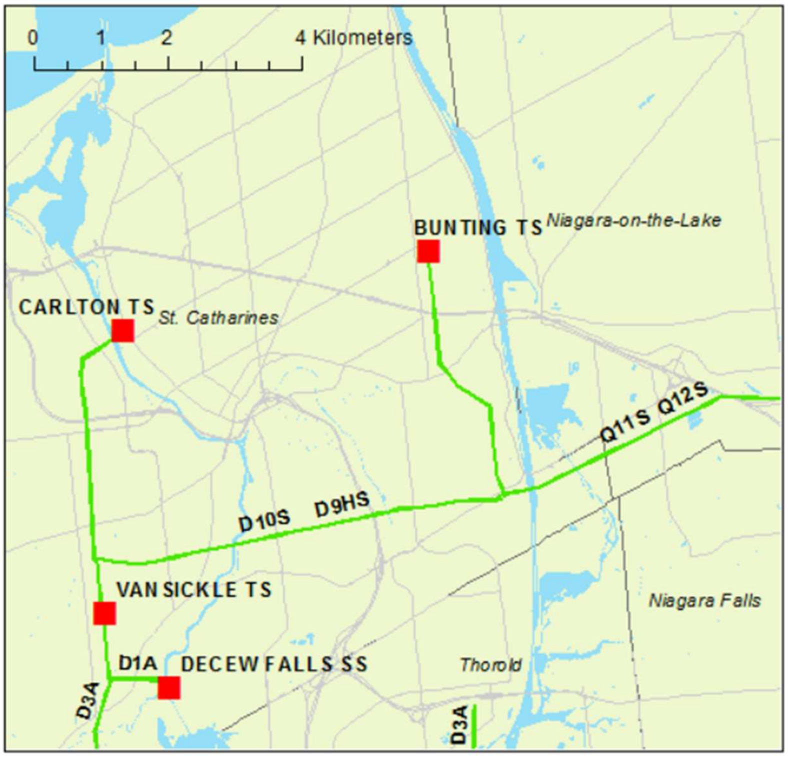

Figure 7-6: Map of Carlton TS and Bunting TS

Table 7-6: Carlton TS and Bunting TS Load Forecast

Station	LTR MW	Act. [1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Carlton TS	95.4	82.6	89.2	90.1	91.1	92.2	93.3	94.6	95.9	97.3	98.9	100.3	105.7	2029
Bunting TS	78.2	54.4	57.8	58.3	58.8	59.6	60.4	61.4	62.4	63.6	64.7	65.9	77.1	---
Total	173.6	137.0	147.1	148.4	149.9	151.8	153.7	156.0	158.3	160.9	163.6	166.2	182.8	----

1. Actual summer load adjusted for extreme weather

Both Carlton TS and Bunting TS also have renewal work planned. The LV switchyard at Carlton TS is over 50 years old and refurbishment is required. The Transformer T3 at Bunting TS is also over 50 years and identified for replacement.

7.3.4.1 Alternatives and Recommendation

The following alternatives were considered to address the current and future capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not address the stations sustainment need. Carlton TS load also exceeds its LTR and action is required to address the issue.

- **Alternative 2 –Carry out Asset Renewal at Carlton TS and Bunting TS**: Monitor Carlton TS loading and transfer excess load to Bunting TS: The station refurbishment work will be carried out at both stations. Carlton TS load growth will be monitored to see if the actual summer peak loads are close to the mid-term forecast. When the actual load is approaching the forecast, the respective LDC will re-evaluate and transfer the excess load over the LTR from Carlton TS to Bunting TS. The cost to transfer the load between stations is estimated to be $5M.

The TWG recommendation is that it is prudent to monitor the area load and complete load transfer at nearby stations with available station capacity when required. The TWG recommends Alternative 2 as the preferred and cost-effective alternative for addressing the need.

7.4 Asset Replacement for Major HV Transmission Equipment

As discussed in Section 6.3, Hydro One has identified the need for replacement of major HV transmission assets over the next ten years at several Niagara Region Hydro One stations as well as two small line sections. Details of the work along with its planned in-service year is given in Table 7-7.

Table 7-7: Niagara Region – Asset Replacement Plans

No.	Station /Line	Planned Work	Planned I/S Date[1]
1	Thorold TS	Replace the existing 45/60/75 MVA T1 transformer with a new 45/60/75 MVA unit.	2024
2	Glendale TS	Replace the existing T1/T2 45/60/75 MVA transformers, with new 45/60/75 MVA units.	2027
3	Crowland TS	The existing 115/27.6 kV T5/T6 DESN will be replaced by a new 230/27.6 kV DESN rated for 170 MW.	2027
4	Murray TS	Replace the existing 45/60/75 MVA transformers T11 and T12 with new 60/80/100 MVA units. Replace the existing 45/60/75 MVA transformers T13 and T14 with new 60/80/100MVA units.	2027 2031
5	Bunting TS	Replace the existing 40/53/67 MVA transformers, with new 45/60/75 MVA units	2029
6	Vansickle TS	Replace LV Switchgear	2032
7	Allanburg TS	Replace Autotransformer T3	2032
8	115kV Line D1A/D3A	115kV kV line refurbishment of a 5 km line section between Gibson Jct and Thorold TS with conductor to be replaced due to asset condition	2024
9	115kV Line Q2AH	115kV line refurbishment of 11.2km between Rosedene Jct. and St. Anns Jct. with conductor to be replaced due to asset condition	2025

1. The planned in-service date is tentative and is subject to change

The TWG recommends that Hydro One proceed with the above work to ensure that the system meets reliability criteria and supply to customers is not affected.

7.5 Load Security – 115kV circuits A6C/A7C

As discussed in Section 6.4.1 the *Allanburg Load Rejection scheme* trips 115kV circuits A6C/A7C under certain contingencies to prevent stations supplied from these circuits being subjected to excessive voltage declines.

The *Allanburg Load Rejection Scheme* is designed to address post contingency voltage decline issues following the coincident loss of Allanburg 230/115 kV Autotransformers T1 and T2. The coincidental loss of Allanburg T1 and T2 transformers will result in circuits A6C and A7C being disconnected from the Allanburg TS 115kV and buses radially connected to circuits D1A and A36N, respectively. As such, this causes excessive voltage to decline at stations supplied from circuits 115kV A6C and A7C. The scheme rejects the load connected to circuits A6C and A7C and will prevent the radial feeds (from Decew Fall GS on D1A and the Niagara Corridor on A36N) from trying to support the load of A6C and A7C.

The load security need arises from Section 7.1 of the ORTAC. As defined under this section, Not more than 150MW of load may be interrupted by configuration and by planned load curtailment or load rejection, excluding voluntary demand management. The A6C/A7C load forecast is provided in Table 7-8.

Table 7-8: 115kV Circuit A6C/A7C -Connected loads

Load	ORTAC L/R Limit	Act.[1]	Load Forecast										
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042
A6C/A7C	150	209.6	219.3	227.8	237.1	247.9	252.6	257.5	278.7	281.1	283.1	283.4	297.0
Crowland TS		93.6	100.9	108.8	110.6	112.6	114.1	115.9	117.6	119.6	121.3	121.2	128.5
A6C/A7C post Crowland[2]		-	-	-	-	-	138.5	141.7	161.2	161.5	161.9	162.2	168.5

1. Actual summer load adjusted for extreme weather
2. After Crowland TS conversion to 230KV as per Section 7.3.2

This forecast exceeds the permissible limit set by ORTAC. It also exceeds the A6C/A7C line limit for loss of one of the two circuits.

7.5.1.1 Alternatives and Recommendation

The following alternatives were considered to address the current and future capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not address the ORTAC load security need.
- **Alternative 2 – Reduce Loading on A6C/A7C:** This alternative reduce loading on 115kV circuits A6C and A7C by removing Crowland TS from the A6C/A7C supply. Crowland TS is rebuilt as a 230/27.6 kV station supplied from a new 230kV double circuit line.

The TWG recommends Alternative 2 as the preferred alternative to addressing the load security issue in the ORTAC. This alternative will be partially addressed by converting Crowland TS to a 230kV supply as described in Section 7.3.2. Since the Crowland TS work will not be completed till 2027, the issue will be managed by operational measures. Load can be restored within 15 minutes by opening both T1 and T2 disconnect switches and supplying all the Allanburg 115kV load from the remaining T3 and T4 autotransformers during a coincident T1 and T2 outage. This work reduces the severity of the load security issue. The loading on the A6C/A7C will continue to be monitored and reviewed in the next planning cycle with the option to transfer Allanburg TS DESN to 230kV.

8 CONCLUSION AND RECOMMENDATION

This Regional Infrastructure Plan report concludes the Regional Planning process for the Niagara Region.

The major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon 2023-2032 are provided in Table 8-1 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 8-1: Recommended Plans over the next 10 Years

No.	Need	Recommended Action Plan	Lead	Timing[1]	Budgetary Estimates[2]
1	230 kV circuit Q28A – Additional capacity required	Uprate circuits between Beck 2 SS and Abitibi Jct. to meet expected load demand	Hydro One	TBD[3]	$3M
2	Loading in the Lincoln area exceeding supply capability	Build new 2 x 50/83MVA, 230kV/27.6 station	Hydro One	2028	$45M
3	Crowland TS: Station loading exceeds LTR	Build new 2 x 75/125MVA, 230kV/27.6 station and a new 18 km line from Abitibi Jct to Crowland TS	Hydro One	2027	$128M
4	Murray TS T11/T12 DESN: DESN loading exceeds LTR. Transformers T11/T12 need to be replaced	Replace existing 45/75MVA transformers with larger 60/100MVA units	Hydro One	2027	$41M
5	Carlton TS: T1/T2 DESN loading exceeds LTR	Transfer excess load to Bunting TS	Alectra	2029	$5M
6	**Asset Replacement:** Thorold TS Glendale TS Carlton TS Bunting TS Murray TS T13/T14 Vansickle TS Allanburg TS 115kV Line D1A/D3A 115kV Line Q2AH	Refurbish/replace major high voltage transmission equipment	Hydro One	 2024 2027 2027 2029 2031 2032 2032 2024 2025	 $43M $55M $55M $45M $27M $14M $20M $4M $10M

1. The planned in-service dates are tentative and subject to change
2. Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required)
3. Contingent on customer

9 REFERENCES

[1] Niagara Region Integrated Resource Plan - Dec 2022

[2] Niagara Region NA report - May 2021

[3] Niagara Region Regional Infrastructure Plan Report - March 2017

APPENDIX A: NIAGARA REGION - STEP-DOWN TRANSFORMER STATIONS AND SUPPLY CIRCUITS

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Allanburg TS	115	A6C/A7C
2	Beamsville TS	115	Q2AH
3	Bunting TS	115	Q11S/Q12S
4	Carlton TS	115	D9HS/D10S
5	CNPI Station #17 MTS	115	A37N
6	CNPI Station #18 MTS	115	A37N
7	Crowland TS	115	A6C/A7C
8	Dunnville TS	115	Q2AH
9	Glendale TS	115	Q11S/Q12S, D9HS/D10S
10	Kalar MTS	115	A36N/A37N
11	Murray TS	115	A36N/A37N
12	Niagara West MTS	230	Q23BM/Q25BM
13	NOTL #2 MTS	115	Q11S
14	NOTL York MTS	115	Q12S
15	Port Colborne TS	115	A6C/A7C
16	Stanley TS	115	Q3N/Q4N
17	Thorold TS	115	D1A/D3A
18	Vansickle TS	115	D9HS/D10S
19	Vineland DS	115	Q2AH

APPENDIX B: NIAGARA REGION - DISTRIBUTORS

No.	**Name of LDC**
1	Alectra Utilities
2	Canadian Niagara Power Inc.
3	Grimsby Power Inc.
4	Hydro One Networks Inc. (Distribution)
6	Niagara-on-the-Lake Hydro Inc.
7	Niagara Peninsula Energy Inc.
8	Welland Hydro Electric System Corp.

APPENDIX C: NIAGARA REGION – STATIONS LOAD FORECAST (MW)

Station	LTR MW	2022 Actual[1]	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Allanburg TS	58.7	40	45	45	45	46	46	46	46	46	46	47	47	47	48	48	49	49	50	50	51	51
Beamsville TS	59.0	63	77	79	81	81	82	83	84	85	86	86	88	89	90	92	93	95	97	98	100	102
Bunting TS	78.2	54	58	58	59	60	60	61	62	64	65	66	67	68	70	71	73	74	76	77	77	77
Carlton TS	95.4	83	89	90	91	92	93	95	96	97	99	100	102	104	106	105	105	105	105	106	106	106
CNPI Station #17 MTS	59.4	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	27	27
CNPI Station #18 MTS	59.4	37	36	36	36	36	36	35	35	35	35	35	35	35	35	35	35	36	36	36	36	36
Crowland TS	101.7	94	101	109	111	113	114	116	118	120	121	121	121	122	122	123	124	125	126	126	128	129
Dunnville TS	53.3	30	36	36	37	37	37	38	38	38	39	39	39	40	40	40	41	41	41	42	42	42
Glendale TS (T1/T2)	96.3	41	31	32	32	32	33	33	34	35	35	36	37	37	38	39	40	40	41	42	42	42
Glendale TS (T3/T4)	20.1	14	6	6	6	7	7	7	7	7	8	8	8	9	9	9	10	10	10	11	11	11
Kalar MTS	72.0	44	47	47	54	61	64	66	67	69	69	69	69	70	70	71	72	72	73	74	75	75
Murray TS (T11/T12)	73.2	66	78	78	78	78	78	78	78	79	79	79	79	80	80	81	82	83	83	84	85	86
Murray TS (T13/T14)	79.8	44	42	42	42	43	43	43	43	44	44	44	44	45	45	45	45	45	46	46	46	47
Niagara West MTS	63.4	41	49	57	58	58	59	60	62	63	65	66	68	69	71	73	75	77	78	80	82	84
NOTL #2 MTS	63.5	48	33	34	36	38	39	40	40	41	42	43	44	45	45	46	47	48	49	50	51	52
NOTL York MTS	75.5	17	18	18	19	20	21	22	22	23	23	24	24	25	25	26	26	27	27	28	28	29
Port Colborne TS	50.8	37	35	36	36	36	36	36	36	37	37	37	37	37	38	38	38	38	38	39	39	39
Stanley TS	103.6	57	60	61	62	62	63	64	64	65	65	66	67	67	68	69	69	70	71	72	72	73
Thorold TS	91.3	23	24	25	25	25	25	25	26	26	26	26	26	26	27	27	27	27	27	28	28	28
Vansickle TS	99.5	47	52	52	53	53	54	55	56	57	58	59	60	62	63	64	66	67	68	68	68	68
Vineland DS	26.4	20	21	21	21	21	22	23	23	24	25	25	25	25	26	26	26	27	27	27	27	28
Industrial Customer 1	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Industrial Customer 2	-	7	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Industrial Customer 3	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Industrial Customer 4	-	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Industrial Customer 5	-	20	17	17	24	32	35	38	57	57	57	57	57	57	57	57	57	57	57	57	57	57
Industrial Customer 6	-	4	3	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Industrial Customer 7	-	24	80	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
Industrial Customer 8[2]	-	-	10	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50

1. Actual summer load adjusted for extreme weather.
2. Curtailable load under specific outage conditions.

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APPENDIX D: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
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
MEP	Municipal Energy Plan
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
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

Niagara Integrated Regional Resource Plan

December 22, 2022

Connecting Today.
Powering Tomorrow.

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List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
CNPI	Canadian Niagara Power Inc.
DG	Distributed Generation
DR	Demand Response
DS	Distribution Station
FIT	Feed-in-Tariff
GS	Generating 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
MTS	Municipal Transformer Station
MVA	Megavolt ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NOTL	Niagara-on-the-Lake
NPCC	Northeast Power Coordinating Council

Acronym	Definition
NPEI	Niagara Peninsula Energy Inc.
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station

1. Introduction

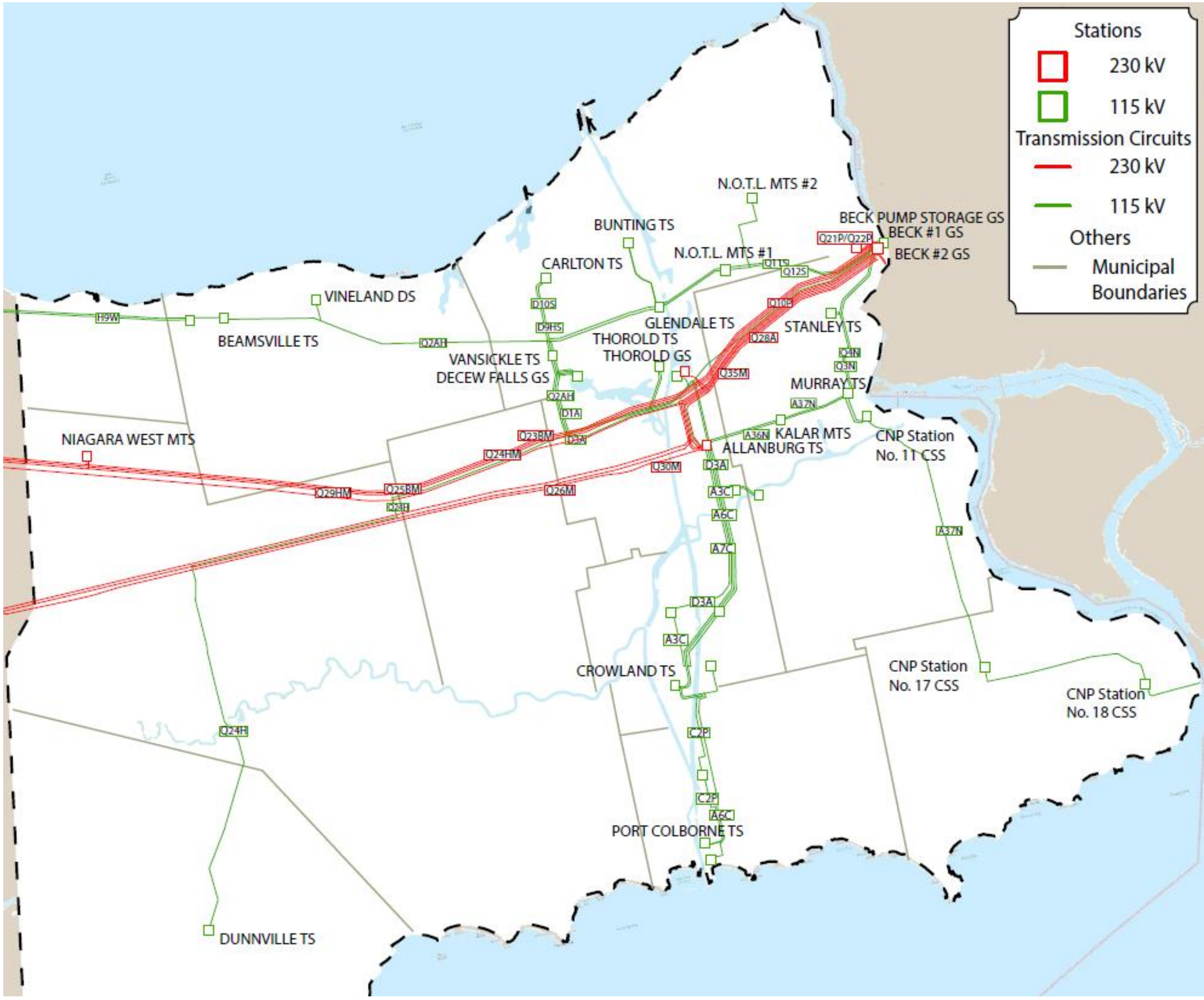
This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Niagara Region over the next 20 years, from 2022 to 2041. The Niagara Region is located between Lake Ontario and Lake Erie, and includes one upper-tier municipality (Regional Municipality of Niagara) and 12 lower-tier municipalities: Fort Erie, Grimsby, Lincoln, Niagara Falls, Niagara-on-the-Lake, Pelham, Port Colborne, St. Catharines, Thorold, Wainfleet, Welland, and West Lincoln.

This region also includes the following First Nations and Métis Nation of Ontario councils:

- Mississaugas of the New Credit
- Oneida Nation of the Thames
- Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council)
- Métis Nation of Ontario Niagara Region Métis Council

The Niagara Region is summer-peaking and, over the last five years, peak electrical demand has remained steady at an average of 810 MW. Electrical supply is provided primarily through 230/115 kilovolt ("kV") autotransformers at Allanburg Transformer Station ("TS"), and is generally served by 230 kV and 115 kV transmission lines and step-down transformation facilities as shown in Figure 1. The region is defined electrically by the 230 kV transmission circuits that connect Sir Adam Beck Generating Station ("GS") #2 in the east to Burlington TS and Middleport in the west. Other large transmission-connected generating facilities include Sir Adam Beck GS #1 and Decew Falls GS connecting to the 115 kV system, and Thorold GS connecting to the 230 kV system.

Figure 1 | Overview of the Niagara Region



The region's electricity is delivered by six local distribution companies ("LDCs"): Alectra Utilities, Canadian Niagara Power Inc. ("CNPI"), Grimsby Power Inc., Hydro One Networks Inc. (Distribution), Niagara on the Lake Hydro Inc., Niagara Peninsula Energy Inc. ("NPEI"), and Welland Hydro Electric System Corp. Hydro One Networks Inc. (Transmission) is the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group, composed of the LDCs, Hydro One, and the IESO.

Development of the Niagara IRRP was initiated in August 2021, following the publications of the Needs Assessment report in May 2021 by Hydro One and the Scoping Assessment Outcome Report in August 2021 by the IESO. The Scoping Assessment identified needs for further assessment through an IRRP. The Technical Working Group was then formed to gather data, identify near- to long-term needs in the region, and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;

- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and demand management and distributed generation assumptions, are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement activities is provided in Section 8; and
- The conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Niagara 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"). The IRRP's recommendations are informed by an evaluation of different options to meet the needs and consider: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

The Niagara electricity demand forecast, provided by the LDCs, projects sustained growth driven by community area, employment area, and rural settlement expansions. This growth spans multiple municipalities, including (but is not limited to): Lincoln, West Lincoln, Welland, Thorold, and Niagara Falls.

The IRRP recommendations below are organized under a near-/medium-term plan and other ongoing or long-term initiatives. This distinction reflects the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons. This approach ensures that the IRRP provides clear direction on investments needed in the near and medium term, while retaining flexibility over the long term, as electrification, energy efficiency, and development plans evolve.

2.1 Near-/Mid-Term Plan

The near- and mid-term plan comprises several recommendations to accommodate load growth, maintain reliability, and optimize asset replacement. Where possible, needs are grouped to align with integrated sets of solutions. These recommendations are summarized in Table 1 and further discussed below.

Table 1 | Summary of the Near/Mid-Term Plan for the Niagara IRRP

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Coordinate load transfers to offload Beamsville TS to Niagara West MTS in the near-term	• 2023

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS, Niagara West Municipal Transformer Station ("MTS"), and Vineland Distribution System ("DS") station capacity • Niagara 115 kV sub-system supply capacity	• Grimsby Power • NPEI • Hydro One Distribution • Hydro One Transmission	• Initiate development of a new 230 kV station supplied from Q23BM and Q25BM, or an expansion of Niagara West MTS	• 2026-2027
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Monitor load growth between regional planning cycles	• Ongoing
• Beamsville TS and Vineland DS station capacity	• Technical Working Group	• Investigate opportunities to target incremental conservation and demand management ("CDM") to Beamsville TS and Vineland DS	• Ongoing
• Crowland TS station capacity and asset replacement • A6C/A7C load security • Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Initiate development for the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM and Q29HM	• 2028
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Develop and implement a new 115 kV sub-system load rejection scheme	• 2024

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Uprate Q28A	• 2024
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Monitor load growth between regional planning cycles	• Ongoing
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to the 115 kV sub-system	• Ongoing
• Murray TS (T11/T12) station capacity	• NPEI • Hydro One Transmission	• Monitor load growth and transfer load in excess of the station limit to Murray TS transformer 13 and 14 (T13/T14)	• 2023

2.1.1 Load Transfers from Beamsville TS and a New or Expanded 230 kV Station

Stations limits are typically dictated by the lowest rated transformer. Beamsville TS is fully utilized today and there is no remaining capacity for growth. Nearby stations Niagara West MTS and Vineland DS are also forecast to reach their capacity limits by 2026 and 2030, respectively.

The IRRP considered the merits of a portfolio of "non-wires" (non-transmission) options as well as integrated "wires" (transmission) options. Based on planning-level cost estimates and its ability to address capacity shortfalls at the three stations, the Technical Working Group recommends that a new 230 kV station supplied by Q23BM and Q25BM is built. This could be accomplished by expanding the existing Niagara West MTS. Development and implementation for additional capacity should begin as soon as possible for a targeted in-service date of 2026-2027. The next stage of regional planning, the Regional Infrastructure Plan ("RIP") led by Hydro One, should confirm the party who will lead development work (i.e., Grimsby Power, NPEI, or Hydro One).

In the meantime, the IRRP recommends that the local distributors (Grimsby Power, NPEI, Hydro One Distribution), in conjunction with Hydro One Transmission where appropriate, develop a plan to transfer load from Beamsville TS to the other nearby stations (Niagara West MTS, Vineland DS) to manage the urgent Beamsville TS need until the new station is in-service.

2.1.2 Major High Voltage Equipment Replacement of Crowland TS, New 230 kV Transmission Lines, Q28A Upgrade, and Control Actions

The existing T5 and T6 transformers at Crowland TS will require major high voltage ("HV") equipment replacement in 2026, and are forecast to be fully utilized in 2022. Crowland TS, as well as other stations supplied by the A6C/A7C circuits, are also impacted by a load security need that exists today. Moreover, Crowland TS is included in the broader Niagara 115 kV sub-system whose supply capacity need exists today and continues to grow by the end of the planning horizon.

The IRRP developed and evaluated portfolios of non-wires options, standalone generation, and wires alternatives for the multiple needs in this area. Ultimately, the most feasible and cost-effective solution at this time requires wires reinforcements: the upgrade of Q28A, the replacement of 115 kV Crowland TS with a larger 230 kV station supplied by new 230 kV transmission lines from Q24HM and Q29HM, and a new load rejection scheme developed to manage the Niagara 115 kV sub-system load. The IRRP recommends that Hydro One should begin implementation as soon as possible for a targeted in-service dates of 2024, 2024, and 2028 for the load rejection scheme, Q28A upgrade, and new 230 kV station and lines, respectively. Measures to manage the HV equipment replacement infrastructure at Crowland TS should be implemented by Hydro One until the station replacement is in-service.

2.1.3 Load Transfers from Murray TS (T11/T12)

Murray TS (T11/T12) is forecast to be beyond capacity in 2022 during its station peak. Given the small magnitude of this need and the available capacity on the other set of transformers at Murray TS (T13/T14), the IRRP recommends that some load is re-allocated to T13/T14 and growth continues to be monitored.

2.2 Ongoing Initiatives

In addition to the near- and mid-term plan above, two ongoing actions were identified to manage needs expected in the long-term.

2.2.1 Monitor Load Growth

Carlton TS and Kalar MTS are expected to reach capacity in 2028 and 2030, respectively. In the case of Carlton TS, distribution-level load transfers to Bunting TS have been indicated as an option. Given the timing, no firm recommendation is required at this time for either need; the Technical Working Group will continue to monitor load growth and revisit these needs in the next cycle of regional planning. As part of broader monitoring, the Technical Working Group should also keep apprised of and participate in any future Community Energy Plans developed by municipalities of the Niagara Region.

2.2.2 Explore Opportunities for Targeted CDM

In addition to monitoring how the forecast demand materializes, the IRRP recommends continuing to consider opportunities for targeted CDM. During the options analyses, the benefits and potential of incremental, cost-effective CDM were identified – particularly if targeted to manage near-term needs until transmission reinforcements are in-service (as is the case for the Beamsville TS/Vineland DS/Niagara West MTS area, as well as the 115 kV sub-system), or to defer long-term needs (such as at Kalar MTS). The Technical Working Group should continue to support and monitor CDM uptake, and bring these insights into the next cycle of regional planning for the Niagara Region.

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region – defined by common electricity supply infrastructure – over the near, medium, and long-term, and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each region. 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 and determines if there are electricity needs requiring regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3. An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. Other types include bulk system planning and distribution system planning. There are inherent overlaps in all three levels of electricity infrastructure planning. Further details on the regional planning process and the IESO's approach to it can be found in Appendix A.

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.

3.2 Niagara and IRRP Development

The process to develop the Niagara IRRP initiated in August 2021, following the publication of the Needs Assessment report in May 2021 by Hydro One and the Scoping Assessment Outcome Report in August 2021 by the IESO. The Scoping Assessment recommended that the needs identified for the Niagara Region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

4. Background and Study Scope

This is the second cycle of regional planning for the Niagara Region. This region roughly encompasses the municipalities Fort Erie, Grimsby, Lincoln, Niagara Falls, Niagara-on-the-Lake, Pelham, Port Colborne, St. Catharines, Thorold, Wainfleet, Welland, and West Lincoln. This region also includes the following First Nations and Métis Nation of Ontario Councils: Mississaugas of the New Credit, Oneida Nation of the Thames, Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council), and the Métis Nation of Ontario Niagara Region Métis Council. Following a Needs Assessment and Scoping Assessment in 2016, a RIP was initiated by Hydro One and subsequently published in 2017, concluding the first planning cycle for the Niagara Region. An IRRP was not developed, as two electricity needs were identified in 2016, but no further regional coordination was required.

The current cycle of regional planning began in 2021 with the publication of the Needs Assessment Report, where several needs requiring further regional coordination were identified. The 2021 Niagara Scoping Assessment recommended an IRRP for the entire region to address needs in a coordinated manner. This report presents an integrated regional electricity plan for the next 20-year period starting from 2022.

This IRRP develops and recommends options to meet the electricity needs of the Niagara Region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Technical Working Group, and includes consideration of forecast electricity demand growth, CDM, distributed generation ("DG"), transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

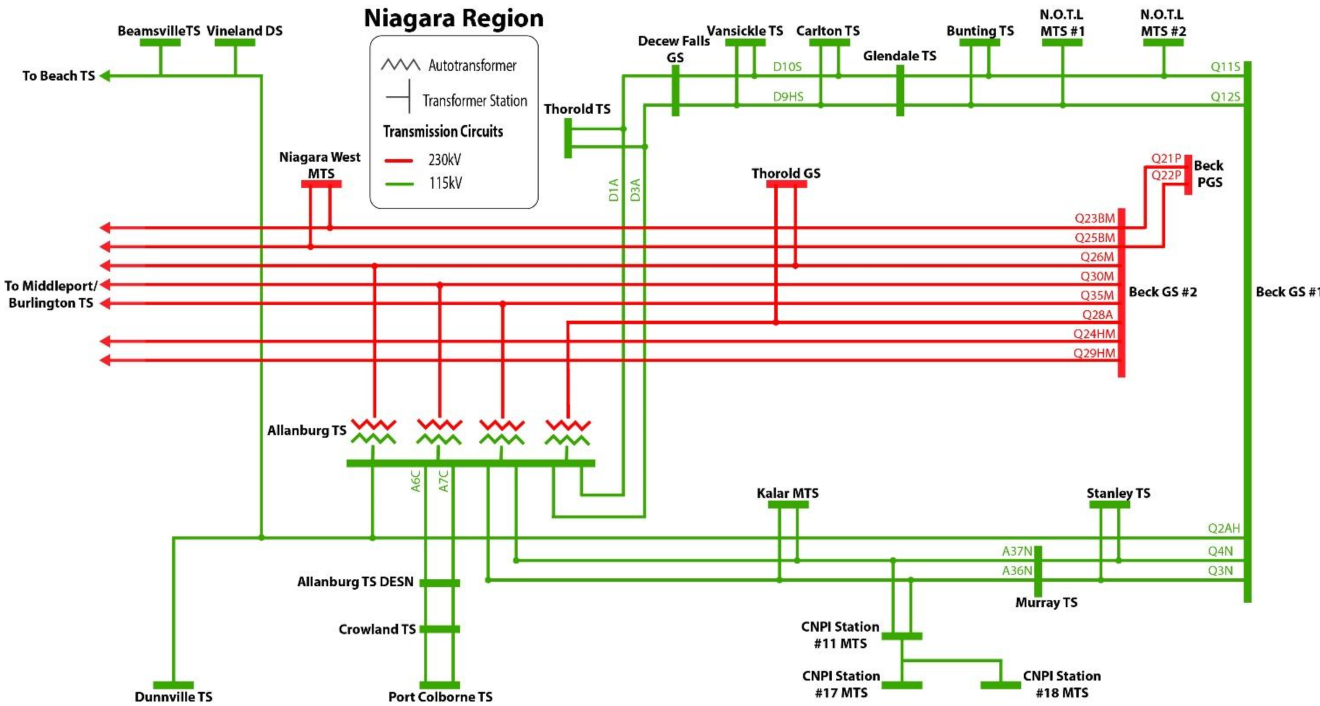
The following transmission facilities were included in the scope of this study:

- Transformer stations: Allanburg TS, Beamsville TS, Bunting TS, Carlton TS, Crowland TS, Dunnville TS, Glendale TS, Kalar MTS, Murray TS, Niagara West MTS, Niagara-on-the-Lake ("NOTL") York MTS, NOTL #2 MTS, Port Colborne TS, Stanley TS, Thorold TS, Vansickle TS, Vineland DS, CNPI #11 MTS, CNPI #17 MTS, CNPI #18 MTS. Except for Niagara West MTS, all stations are supplied from 115 kV transmission circuits.
- 115 kV transmission circuits: Q3N/Q4N, Q11S/Q12S, Q2AH, A36N/A37N, A6C/A7C, D1A/D3A, D9HS/D10S.
- 230 kV transmission circuits: Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M.

The single line diagram of the Niagara Region is shown in Figure 2 below. Note that the bulk system transfer capabilities on the Queenston Flow West interface[1] through the region is not within the scope of the IRRP and would be separately studied in a bulk transmission plan, as required. The schedule of bulk planning activities is identified through the IESO's Annual Planning Outlook.

[1] Includes flow out at Beck (Q25BM + Q23BM + Q24HM + Q29HM) and flow in at Middleport (Q30M + Q26M + Q35M).

Figure 2 | Single Line Diagram of the Niagara Region



The Niagara IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps);
    - Examining the load meeting capability ("LMC") and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC criteria;
    - Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid;
    - Confirming identified asset replacement needs and timing with the transmitter and LDCs;
- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wires alternatives including CDM;
- Engaging with the community on needs and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5. Electricity Demand Forecast

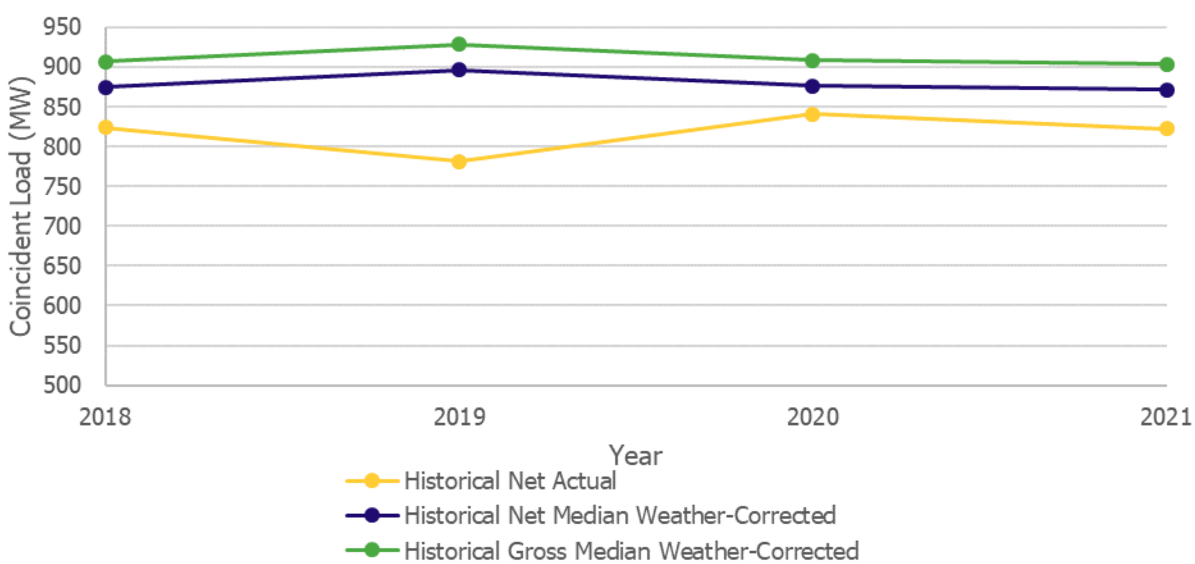
Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the Niagara Region. It highlights the assumptions made for peak demand forecasts, including weather correction, the contribution of CDM and DG, and the development of a high growth scenario. The reference net extreme weather demand forecast is used in assessing the electricity needs of the area over the planning horizon; the high forecast scenario, used as the basis for a sensitivity analysis, is described further in Section 5.7.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Within the Niagara Region, the peak loading hour for each year has historically occurred in the summer.

5.1 Historical Demand

Peak electricity demand within the Niagara Region has been steady over the last four years. Figure 3 below shows the coincident net actual (as observed at the metering point), net median weather-corrected (adjusted to reflect median weather conditions), and gross median weather-corrected (contribution of DG removed) historical demand. The gross median weather-corrected demand has averaged 910 megawatts ("MW") over the past four years, with the peak demand hour for each year occurring consistently in the summer between approximately 4 PM to 7 PM. The 2021 gross median weather-corrected peak at each station in the Niagara Region was used as the starting point for the forecast.

Figure 3 | Historical Demand in the Niagara Region

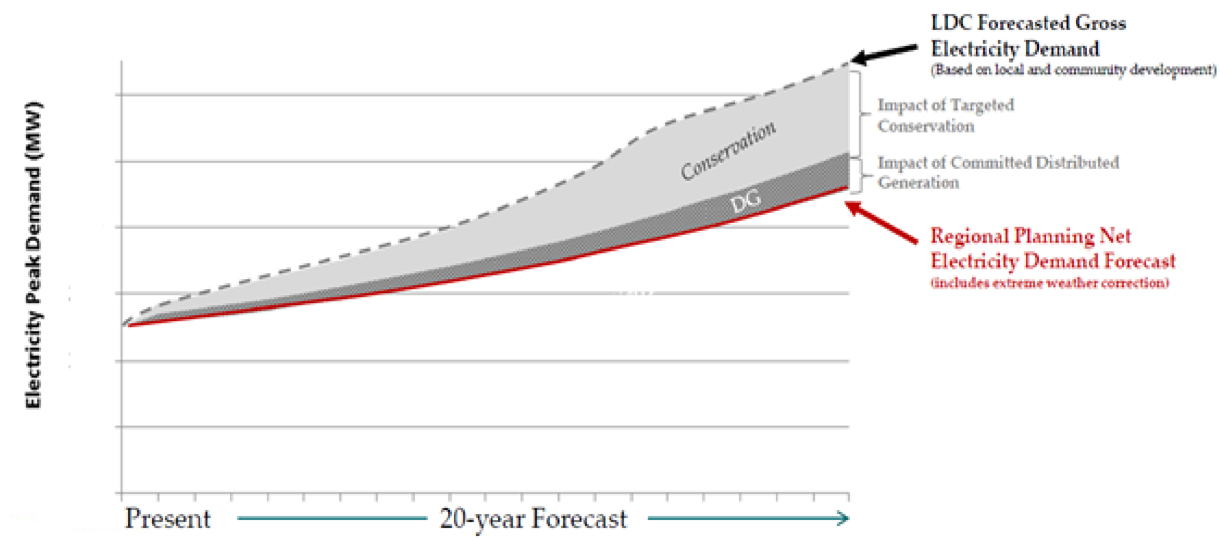


5.2 Demand Forecast Methodology

The steps taken to develop a 20-year IRRP peak demand forecast are depicted in Figure 4. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions (referred to as "normal weather"), were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through previous provincial programs such as Feed-In Tariff ("FIT") and microFIT, and adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments. This net forecast was then used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in Appendix B. Though the Niagara IRRP forecast was created prior to October 2022, the Ontario Energy Board also since published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.

Figure 4 | Illustrative Development of Demand Forecast

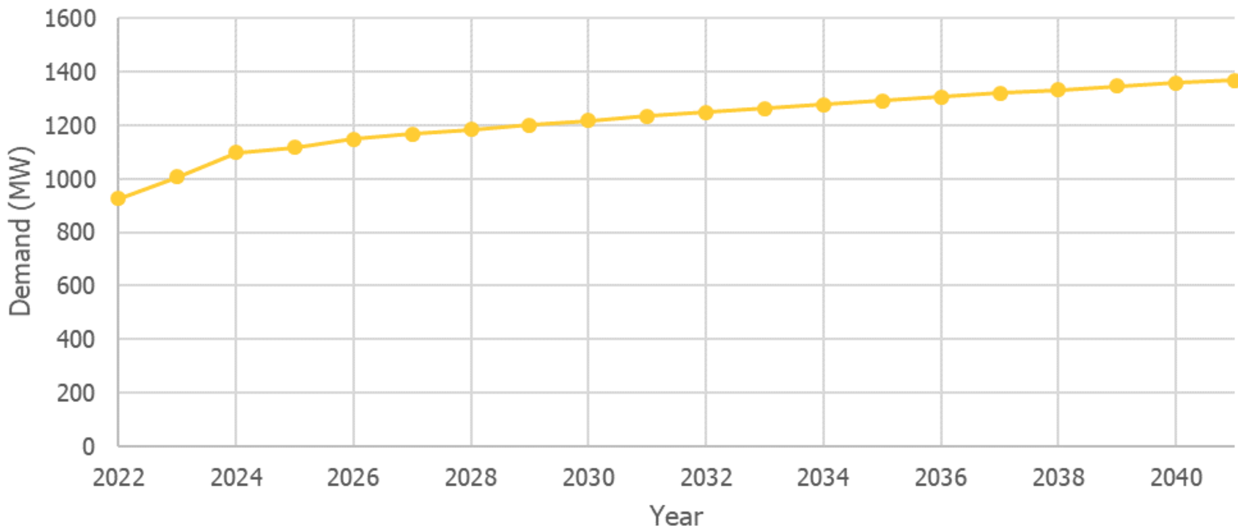


5.3 Gross LDC Forecast

Each participating LDC in the Niagara Region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development, plus known connection applications. The LDCs cited alignment with municipal and regional official plans, and credited them as a source for input data. LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices ("natural conservation"), but not for the impact of future DG or new conservation measures (such as codes and standards and CDM programs), which are accounted for by the IESO (discussed in Section 5.4). The gross LDC forecast assumes median on-peak weather conditions, and station loading that is coincident to the region.

LDCs have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and municipalities and communities which they serve. The IESO typically carries out demand forecasting at the provincial level. More details on the LDCs' load forecast assumptions can be found in Appendix B.2 to B.8. Figure 5 below shows the total gross demand forecast provided by the LDCs for the Niagara Region.

Figure 5 | Total Gross Demand Forecast Provided by LDCs (Median Weather)[2]



5.4 Contribution of Conservation to the Forecast

Conservation and demand management is a clean and cost-effective resource that helps meet Ontario's electricity needs, and has been an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments, as well as CDM program-related activities. These approaches complement each other to maximize conservation results.

The estimate of 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 (i.e., residential, commercial and industrial consumers).

The estimates of demand reduction due to program-related activities account for the 2021-2024 CDM Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs. The 2021 – 2024 CDM Framework is the main piece, in which the IESO centrally delivers programs on a province-wide basis to serve business and low-income customers, as well as Indigenous communities.

Figure 6 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards, and CDM programs) for each of the residential, commercial, and industrial consumers. Additional details are provided in Appendix B.9.

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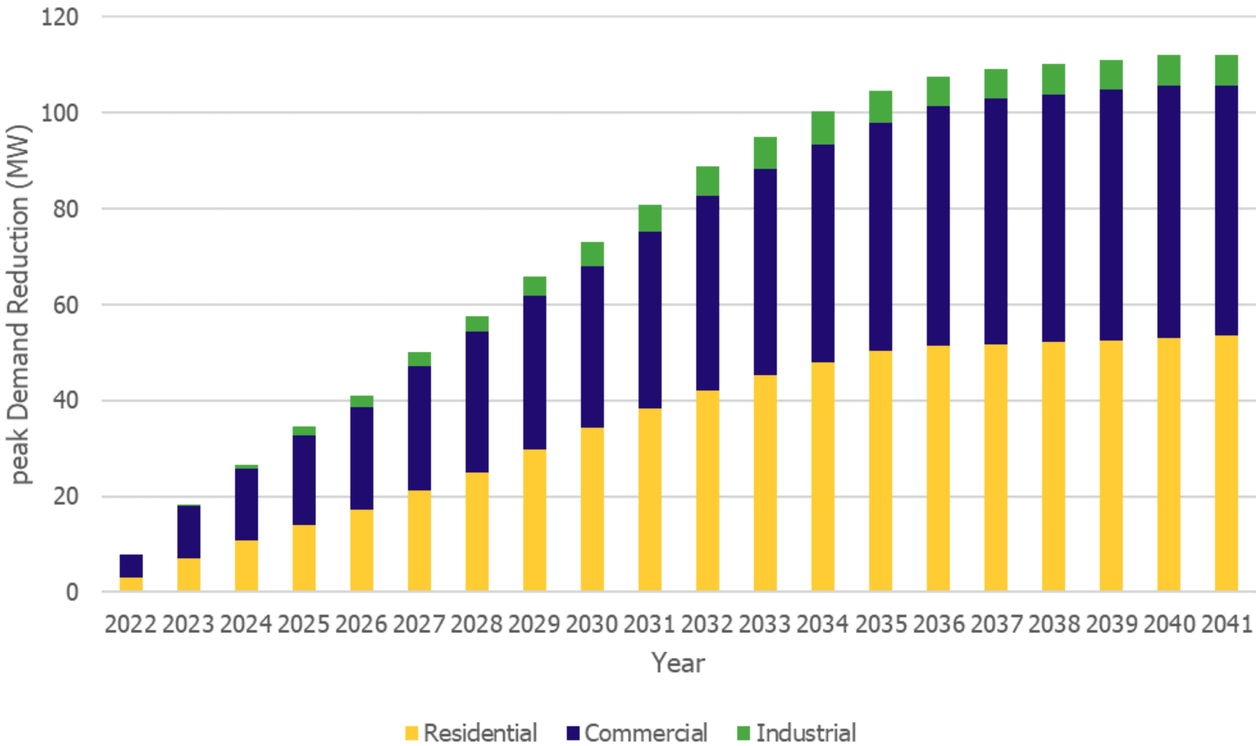
[2] Excludes existing transmission-connected industrial customers in the Niagara Region (historically contributing an average of 15 MW to the coincident peak demand).

Figure 6 | Total Forecast Peak Demand Reduction (Codes, Standards, and CDM Programs)

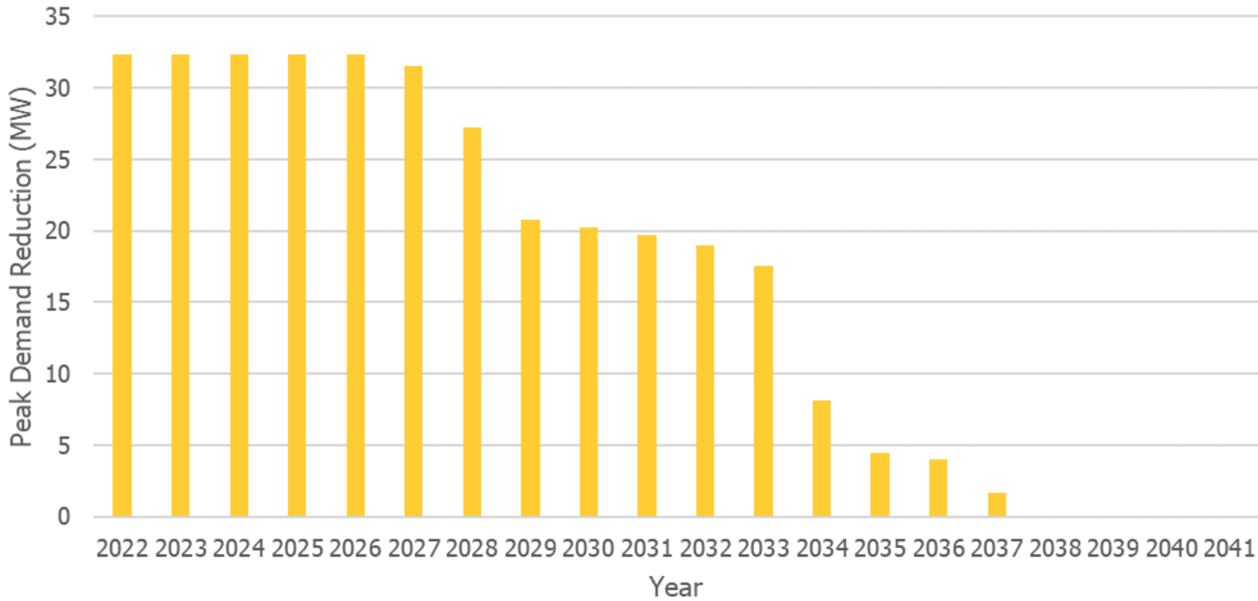


5.5 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, DG in the Niagara Region is also forecast to offset peak-demand requirements. The introduction of Ontario's FIT Program increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and contribution factor assumptions can be found in Appendix B.10. Most of the total contracted installed DG capacity in the Niagara Region is solar, wind, and waterpower, with some biogas, landfill gas, and natural gas facilities.

After reducing the demand forecast due to conservation, as described in Section 5.4, the forecast is further reduced by the expected contribution from contracted DG. Figure 7 shows the impact of DG on reducing the Niagara Region demand forecast. Note that any facilities without a contract with the IESO are not currently included in the DG peak demand reduction forecast.

Figure 7 | Peak Demand Reduction to Demand Forecast, Due to DG



In the long term, the contribution of DG is expected to diminish as their contracts expire. A total of 32 MW of peak contribution is identified for the Niagara Region in 2022, reducing throughout the 2030s to 0 MW by 2038. This reduction is reflected in the high forecast scenario (see Section 5.7 for more details on its development and assumptions), but not the reference forecast. Rather, the reference Niagara IRRP forecast assumes a constant contribution of approximately 32 MW each year for the entire study period. This aligns with the Technical Working Group decision to assume that already-existing DG facilities with expired contracts will continue to offset demand.

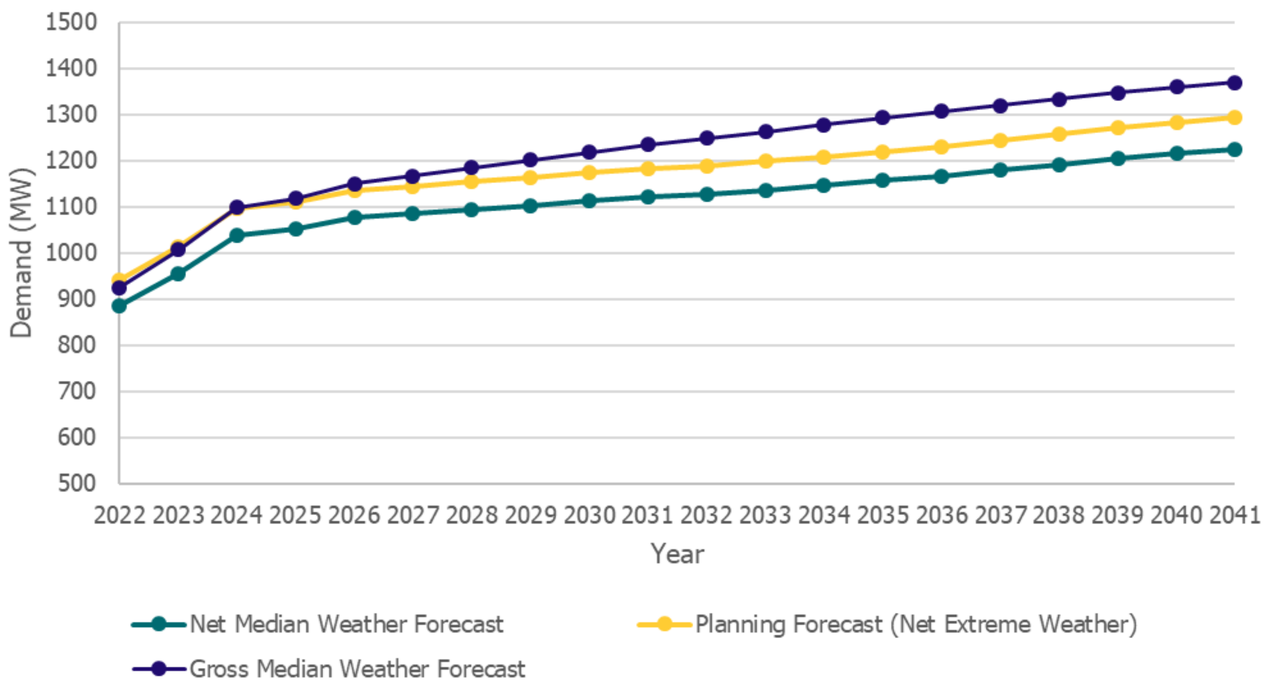
5.6 Net Extreme Weather ("Planning") Forecast

The net extreme weather forecast, also known as the "planning" forecast, is created by adjusting the net median weather forecast (the gross demand forecast, plus the forecast DG and conservation impacts as described above) for extreme weather conditions. The weather correction methodology is described in Appendix B.1.

Note that this planning forecast is coincident, meaning that each station forecast reflects its expected contribution to the regional peak demand level. This supports the identification of need dates for regional needs that are driven by more than one station. For station-specific needs, the non-coincident forecast is calculated by applying a non-coincidence factor. The factor is based on the historical non-coincident peaks of each station compared to the station's contribution to the region's coincident peaks over the past six years.

The coincident net extreme weather forecast for the Niagara Region is shown in Figure 8 below.

Figure 8 | Net Extreme Weather ("Planning") Forecast for the Niagara Region[3]



5.7 High Forecast Scenario

The Technical Working Group opted to develop a high forecast sensitivity scenario for the Niagara Region. This higher demand scenario is to take into account a variety of factors that could drive demand higher over the next 20 years, including but not limited to: electric vehicle charging infrastructure, electrified space heating installations, unanticipated new industrial customers, or general higher-than-expected growth. However, the Technical Working Group did not have specific end-use data available to develop the high forecast. Instead, the DG contribution to peak (as described in Section 5.5) was removed according to contract expiries, resulting in approximately 3% higher total regional load by 2041 when compared to the reference planning forecast. The impact on stations with greater contracted DG is higher.

The high forecast also included several large industrial customers whose connection was uncertain at the time of finalizing the reference forecast. These include customers that members of the Technical Working Group were aware of and liaising with, as well as customers that initiated a System Impact Assessment with the IESO during the Niagara IRRP development. In total, another 132 MW was added due to this assumption, when compared to the reference planning forecast. This is shown in Figure 9.

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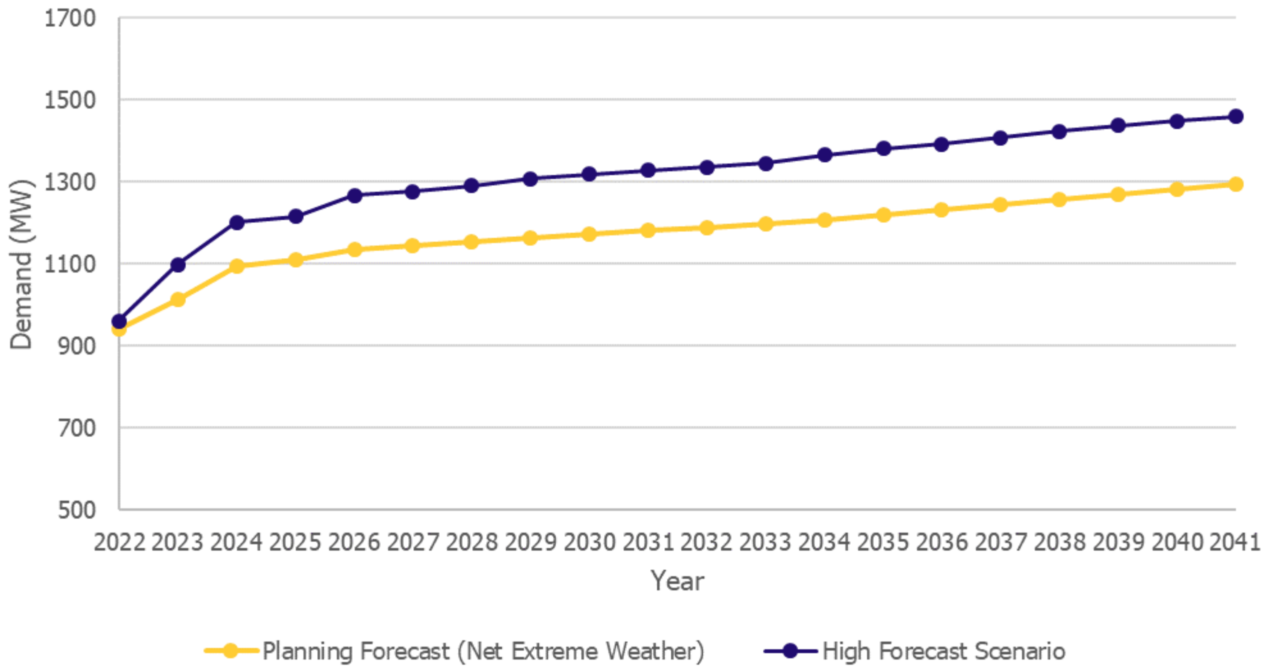
[3] See footnote 2.

Figure 9 | High Forecast Scenario for the Niagara Region[4]



The higher demand scenario was not used to drive any firm recommendations for this IRRP; however, it was used to help the Technical Working Group identify where the future pinch points may be and when they could materialize. This information can also be useful for communities conducting Community Energy Plans, for the Technical Working Group in determining areas to monitor in future planning cycles, and for communities and stakeholders as they think about various projects in the region. Moreover, during this IRRP, the Technical Working Group also considered the flexibility of evaluated options to accommodate greater long-term growth. This is later described in Section 7.

5.8 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 stations 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. The profiles were then scaled to match the IRRP peak planning forecast for each year. As described later in Section 7, 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

[4] See footnote 2.

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. Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of ORTAC, NERC TPL-001-4, and Northeast Power Coordinating Council ("NPCC") Directory #1 standards, the Technical Working Group identified electricity needs in the near-, medium- and long-term timeframes. These needs can be categorized according to the following:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during 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 more limited by downstream or upstream equipment, i.e., breakers, disconnect switches, low-voltage bus or high voltage circuits.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the LMC of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-4, and NPCC Directory #1. LMC studies are conducted using power system simulation analyses.
- **Asset Replacement Needs** are identified by the transmitter by an asset condition assessment, which 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. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs 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 needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** 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.

Technical study results for the Niagara IRRP can be found in Appendix G. The needs identified are discussed in Sections 6.2 – 6.5 below.

6.2 Station Capacity Needs

In the near/mid-term, there are summer station capacity needs at Beamsville TS, Murray TS, Crowland TS, and Niagara West MTS. In the longer term, there are station capacity needs at Carlton TS, Vineland DS, and Kalar MTS. Table 2 below summarizes transformer capacity limitations for the Niagara Region.

Table 2 | Summary of Station Capacity Needs in the Niagara Region

Need	10-day LTR Rating (MW)[5]	Need Date[6]	Size of Need by 2041
Beamsville TS	57	2022	44
Murray TS (T11/T12)	72	2022	14
Crowland TS	96	2022	25
Niagara West MTS	60	2026	22
Carlton TS	94	2028	11
Kalar MTS	68	2030	7
Vineland DS	25	2030	3

6.2.1 Beamsville TS, Niagara West MTS, and Vineland DS

The three stations supplying the Lincoln, West Lincoln, and Grimsby areas (Beamsville TS, Niagara West MTS, and Vineland DS) are forecast to reach their individual station limits, as well as their collective limit (sum of their LTRs). Beamsville TS and Vineland DS each comprise two 115 kV/27.6 kV transformers, with summer LTRs of 57 MW and 25 MW, respectively. The Beamsville TS capacity need exists today (Figure 10), whereas the Vineland DS need is forecast to start in 2030 (Figure 12). Niagara West MTS consists of two 230 kV/27.6 kV transformers, with a summer LTR of 60 MW and a need beginning in 2026 (Figure 11). Cumulatively, the capacity need at these three stations grows to 57 MW by 2041 (Figure 13).

[5] Assuming a 0.9 power factor.
[6] Based on non-coincident station forecasts, as explained in Section 5.6.

Figure 10 | Beamsville TS Capacity Need

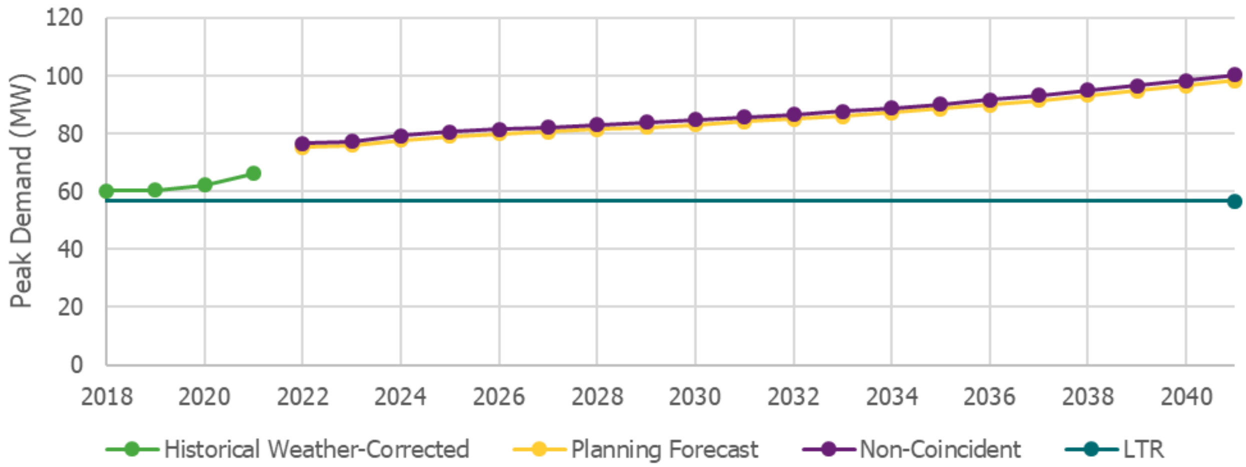


Figure 11 | Niagara West MTS Capacity Need

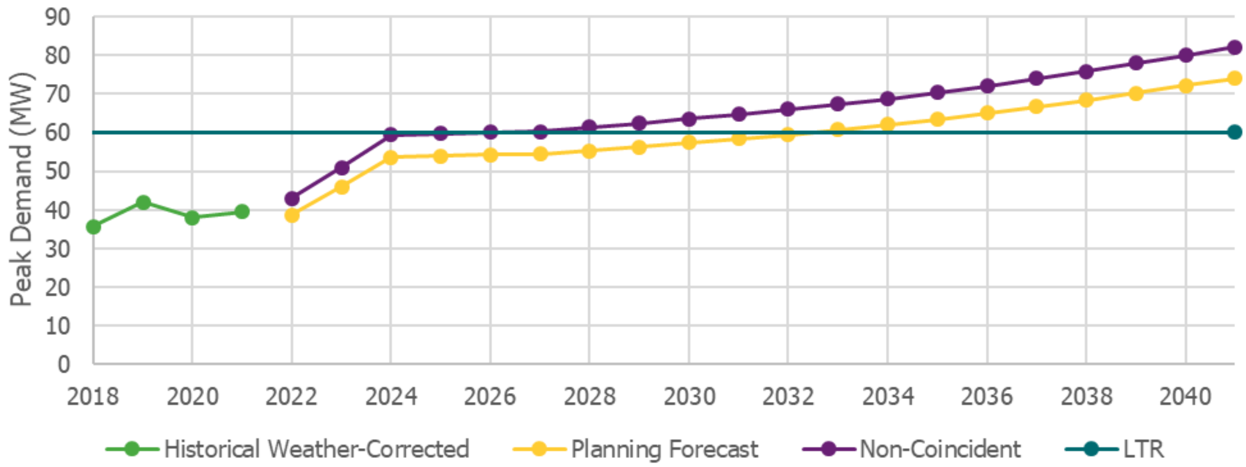


Figure 12 | Vineland DS Capacity Need

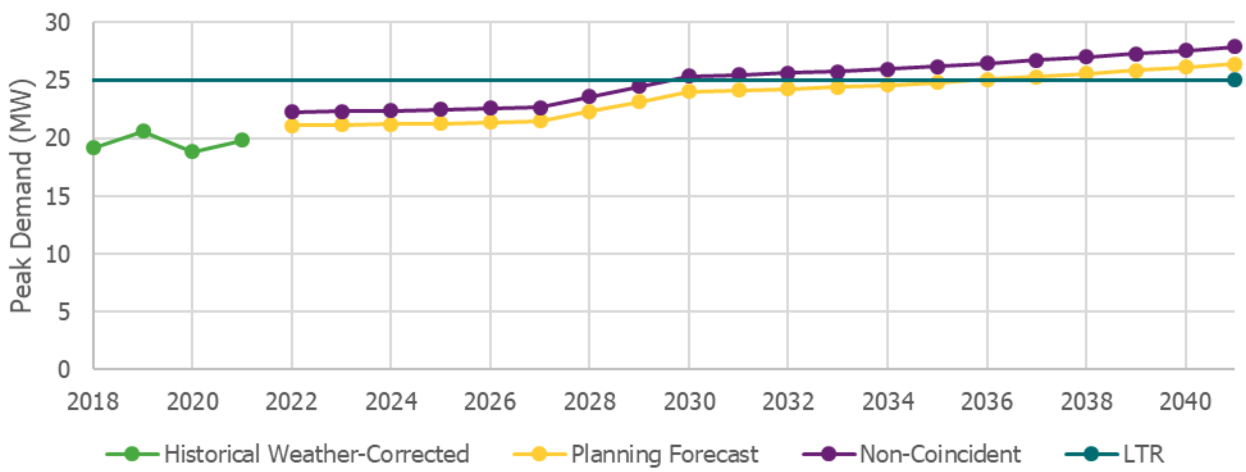
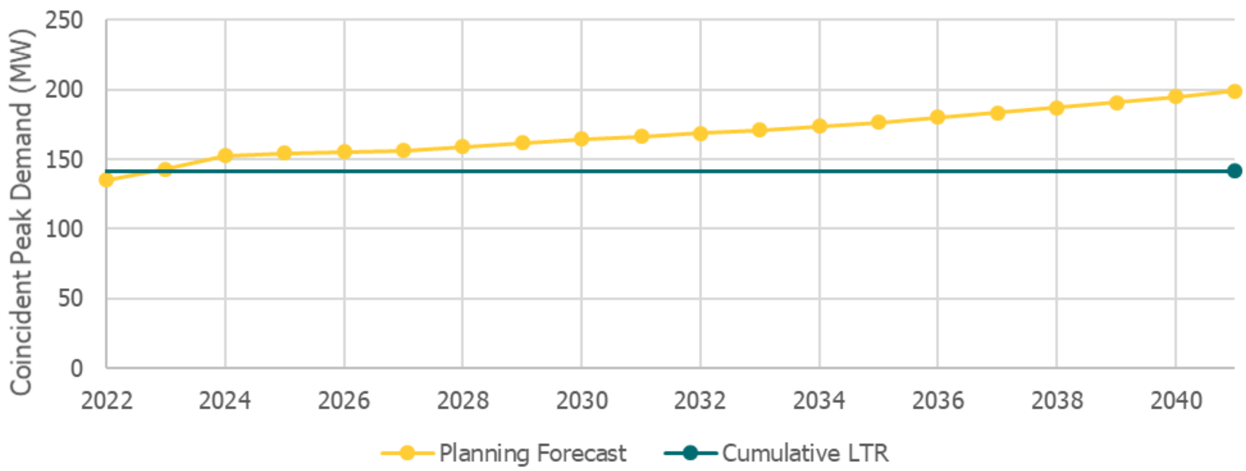


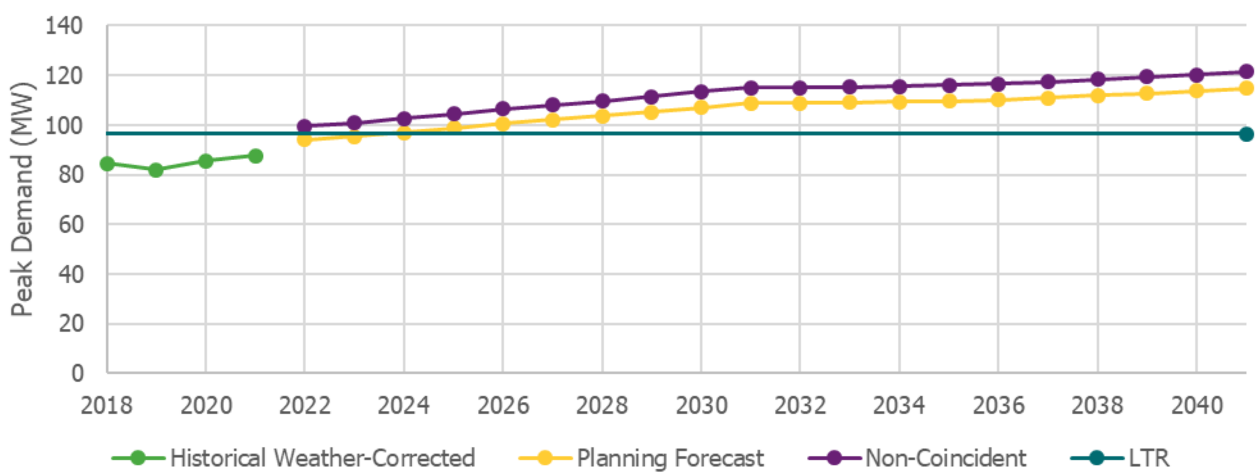
Figure 13 | Beamsville TS, Vineland DS, and Niagara West MTS Cumulative Coincident Capacity Need



6.2.2 Crowland TS

Supplying Welland, Crowland TS is forecast to reach its summer station capacity limit in 2022 and grow to a 25 MW need by 2041. This station comprises two 115 kV/27.6 kV transformers with an LTR of 96 MW.

Figure 14 | Crowland TS Capacity Need



6.2.3 Carlton TS, Kalar MTS, and Murray TS (T11/T12)

Carlton TS and Kalar MTS each comprise two 115 kV/13.8 kV transformers, with summer LTRs of 94 MW and 68 MW, respectively. Carlton TS is forecast to reach capacity starting in 2028 (Figure 15) while the Kalar MTS need arises in 2030 (Figure 16). Each need will increase to 11 MW and 7 MW, respectively, by 2041. Murray TS consists of four 230 kV/13.8 kV transformers; T11 and T12 have a summer LTR of 72 MW, whereas T13 and T14 are rated to 77 MW. The T11/T12 capacity need exists today, growing to 14 MW by 2041 (Figure 17).

Figure 15 | Carlton TS Capacity Need

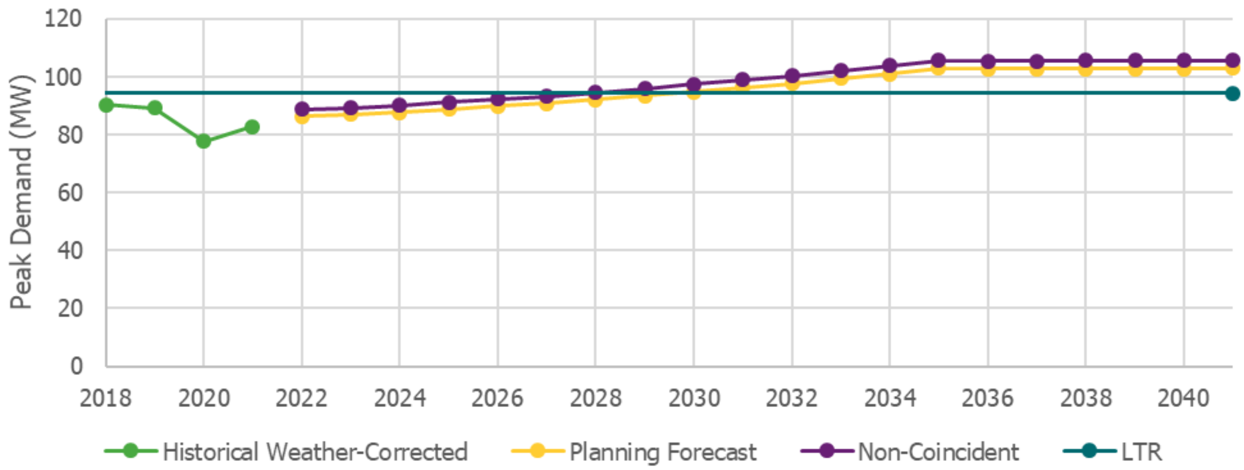


Figure 16 | Kalar MTS Capacity Need

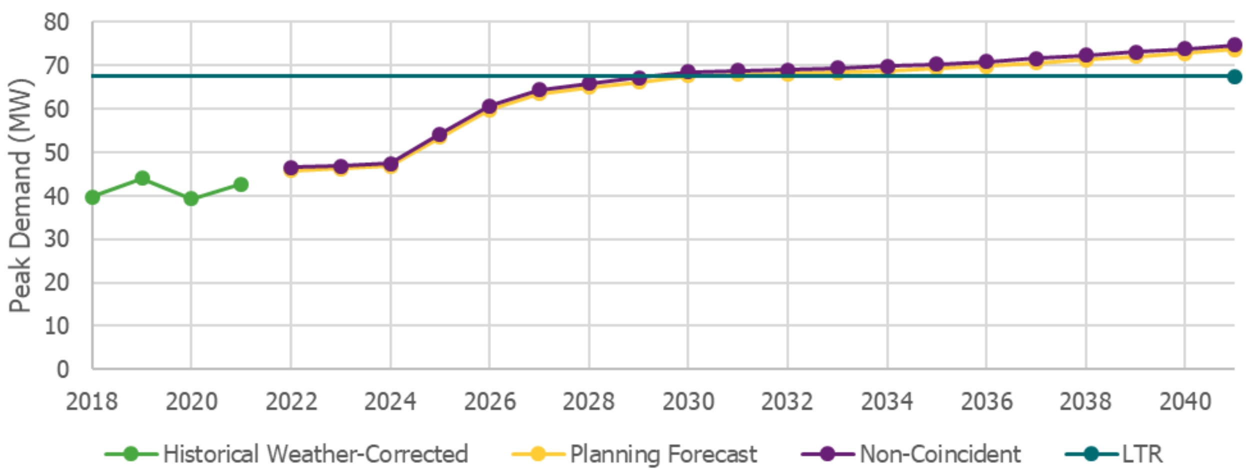


Figure 17 | Murray TS (T11/T12) Capacity Need

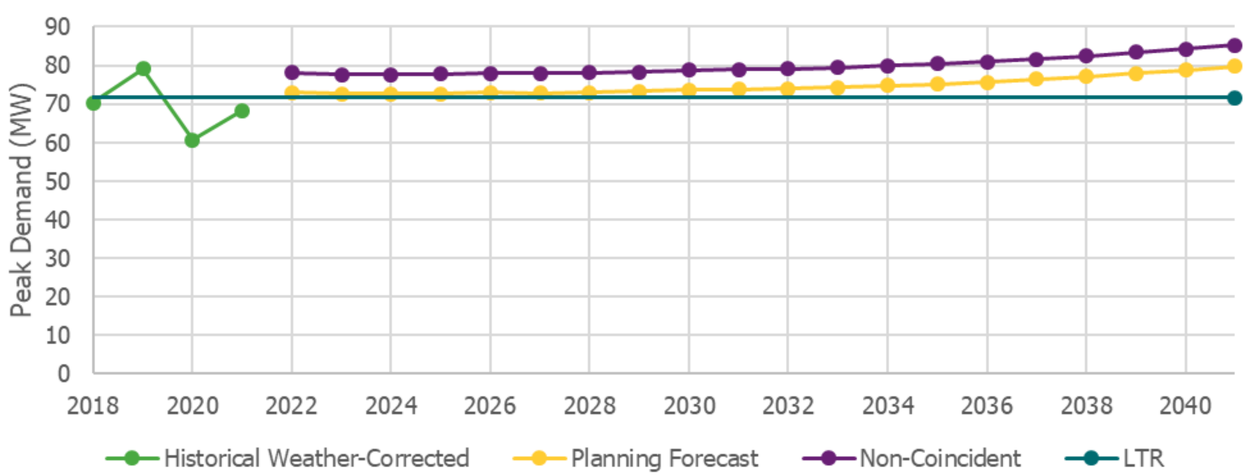
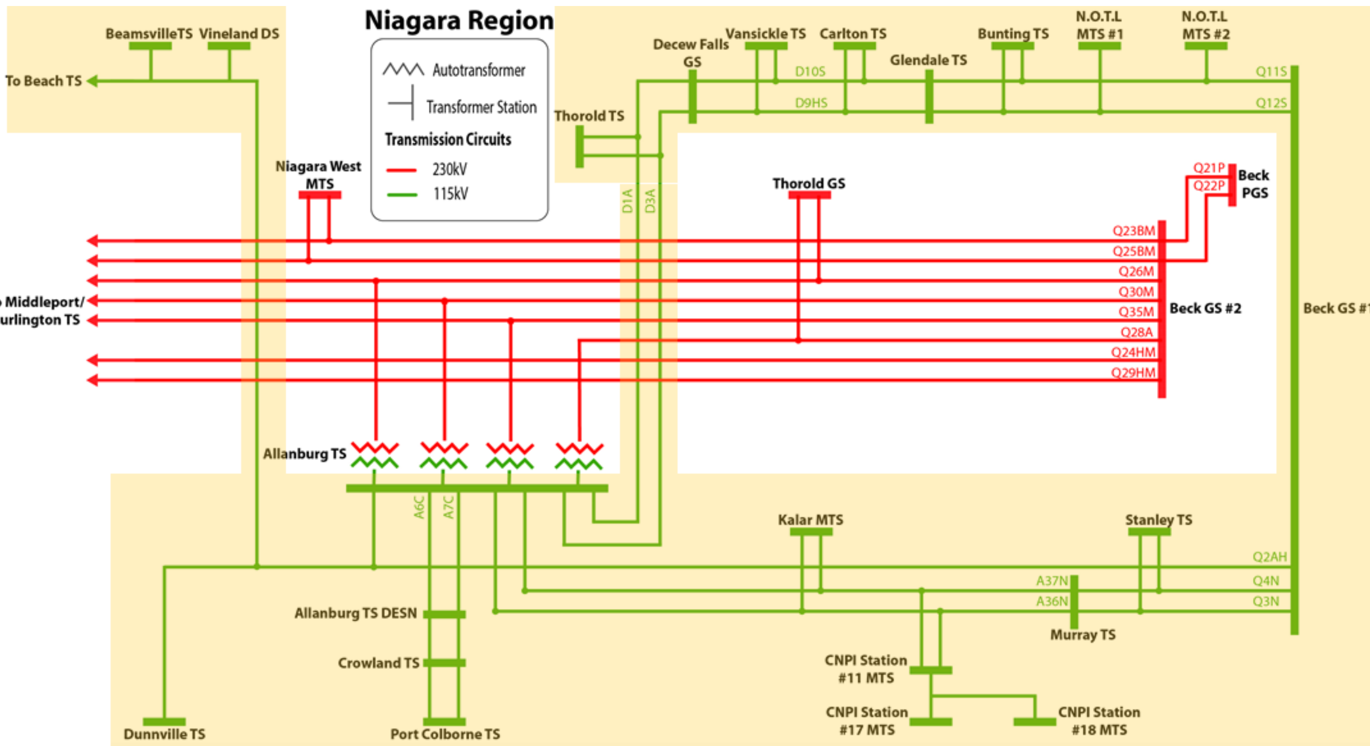


Figure 15 to Figure 17 demonstrate the non-coincident peak demand forecasts at these stations compared to their individual LTRs. Note that these station capacity needs have been presented together in this sub-section, since this IRRP is not yet recommending infrastructure reinforcements to address them. Section 7.2.1.3 describes this in more detail.

6.3 Supply Capacity Needs

The majority of load in the Niagara Region is supplied through its 115 kV transmission sub-system, which in turn is supplied from the 230/115 kV autotransformers at Allanburg TS, Sir Adam Beck GS #1, and Decew Falls GS. The LMC of the 115 kV sub-system is therefore limited by the capability at Allanburg TS under the various planning scenarios and applicable contingencies. The sub-system is demonstrated in Figure 18.

Figure 18 | Niagara Region's 115 kV Sub-System (Highlighted Yellow)

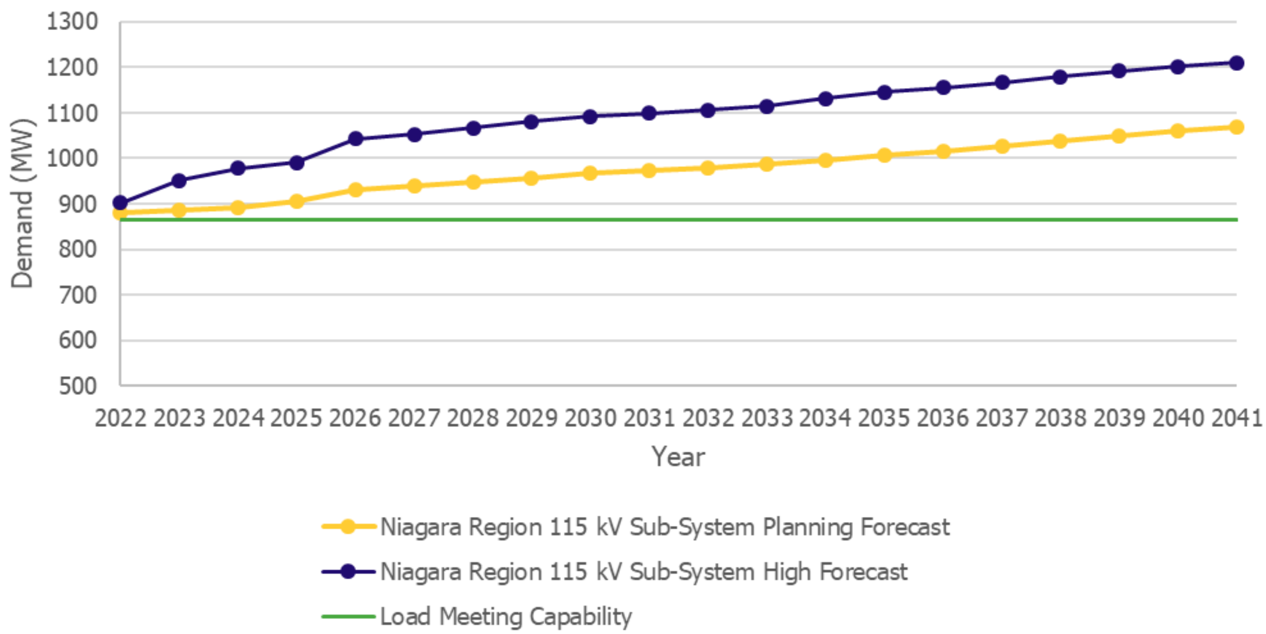


The LMC of the Niagara 115 kV sub-system, presented in Figure 19 against the forecast load, reflects limitations of the existing transmission system. Under certain outage and contingency conditions (such as contingencies impacting two circuits between Beck GS #2 and Middleport/Burlington, or Beck GS #1), the lowest-rated Allanburg autotransformer is overloaded and is the first limiting phenomenon that restricts total reliable supply into the 115 kV sub-system. However, the LMC for this area can also be restricted by other phenomena, including the thermal capability of a section of Q28A during other contingency events and specific generation outage conditions. There are further, more local restrictions within this sub-system too – such as thermal constraints limiting the supply to loads between Allanburg TS and Beck GS #1 through the 115 kV circuits.[7] All of these transmission limits are described in Appendix G.

[7] This particular need, which occurs under outage conditions, could be addressed through permissible operational control actions and would be impacted by a customer's System Impact Assessment that is ongoing at the time of regional planning.

Between 2018 – 2021, the 115 kV sub-system has had a peak coincident weather-corrected load of up to approximately 830 MW. With the reference planning forecast, the 115 kV sub-system load increases such that the supply capacity need grows to approximately 200 MW by 2041; under the high scenario, it is about 340 MW.

Figure 19 | Niagara Region 115 kV Supply Capacity Need



6.4 Asset Replacement Needs

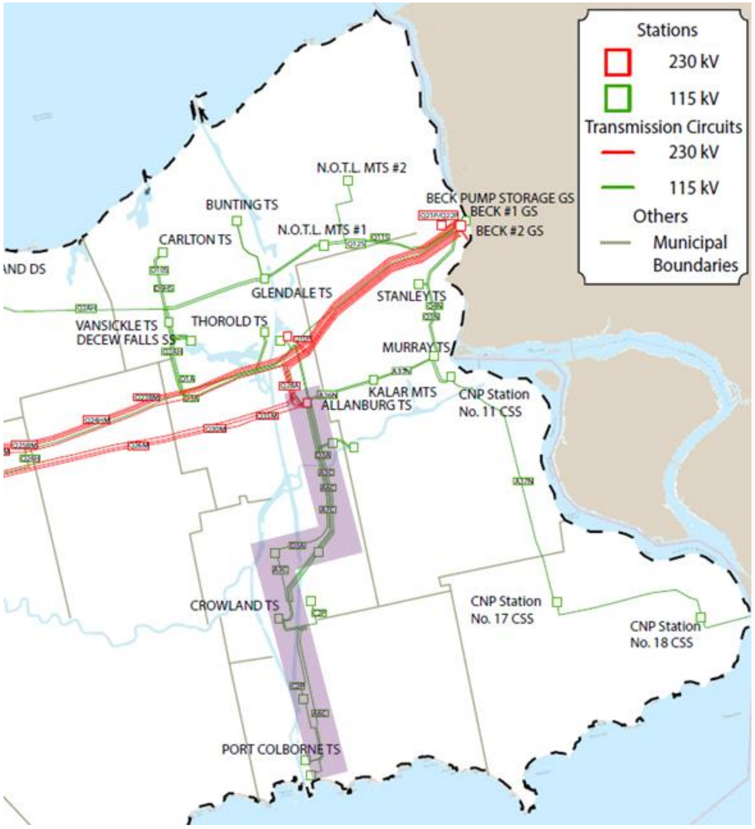
At the time of the Niagara Region Needs Assessment, Hydro One identified a number of assets requiring replacement in the next 10 years. This included Crowland TS, whose transformers were originally scheduled to be replaced with like-for-like 115/27.6 kV 83 megavolt ampere ("MVA") units before 2026. As described in the Niagara Region Scoping Assessment, the Technical Working Group agreed that sustainment plans identified by Hydro One would be assumed to proceed as described in the Needs Assessment – unless an opportunity arose for "right-sizing".

Through the development of the IRRP, during which a more comprehensive demand forecast was created and extended to a 20-year planning horizon, and additional needs were identified or refined, the Crowland TS like-for-like replacement plan was reconsidered. This need and its relevance to the other regional needs are described further in Section 7.4.

6.5 Load Security Needs

The circuits designated as A6C/A7C form a 115 kV double-circuit line from Allanburg TS to Crowland TS, before supplying Port Colborne TS as A6C and C2P. These circuits also serve a number of transmission-connected industrial customers that are south of Allanburg TS, primarily east of the Welland Canal. Figure 20 provides an overview of this portion of the transmission system in the Niagara Region.

Figure 20 | Niagara Region Transmission System: A6C/A7C (Highlighted Purple)



The aforementioned stations and transmission-connected customers on the A6C/A7C circuits are included in the Allanburg Load Rejection Scheme; operational actions are taken to disconnect these loads in the event of certain contingencies to prevent voltage decline upon the coincidental loss of Allanburg T1 and T2. At the 2022 expected load levels on the A6C/A7C circuits, a double contingency on the Q26M and Q28A circuits will trigger over 180 MW of load being disconnected from the system. This is a violation of Section 7.1 of the ORTAC, which specifies that only up to 150 MW of planned load curtailment is permissible under these conditions. The load supplied by A6C/A7C is also expected to grow throughout the study period (i.e., up to 2041). By 2041, it is expected that the load security need will grow to approximately 75 MW in excess of the permissible amount. More details regarding this load security need are provided in Appendix G.

6.6 Summary of Identified Needs

Below is an overview of all needs identified in this Niagara IRRP.

Table 3 | Summary of Needs in the Niagara Region

Need	Need Date
Beamsville TS Station Capacity	2022
Murray TS (T11/T12) Station Capacity	2022
A6C/A7C Load Security Need	2022

Need	Need Date
Niagara 115 kV Sub-System Supply Capacity	2022
Crowland TS Station Capacity	2022
Crowland TS Asset Replacement	2026
Niagara West MTS Station Capacity	2026
Carlton TS Station Capacity	2028
Kalar MTS Station Capacity	2030
Vineland DS Station Capacity	2030

7. Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in the Niagara 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 (including distribution-connected generation and demand response), or CDM.

Section 7.1 begins with a more in-depth overview of all option types considered in IRRPs. Section 7.2 describes the screening approach used to assess which needs would be best suited for a more detailed assessment for non-wires options. Subsequently, Section 7.3 to Section 7.5 present the options that were ultimately developed and evaluated (including a cost comparison) before the Technical Working Group made a recommendation.

7.1 Options Considered in IRRPs

Wires options are always considered in regional planning, and 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 are identified through discussions with the Technical Working Group.

While traditional wires infrastructure is always a viable option for regional needs, some non-wires options are more suitable for specific need types and characteristics. Hence, to select and size suitable generation and other non-wires options, additional work is required – including creation of an hourly load profile, as described in Section 5.8. 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. Some of these characteristics are shown visually in Appendix D for the Niagara Region needs.

High-level cost estimates for wires options are usually provided by the transmitter. In contrast, cost estimates for generation and other non-wires options are based on benchmark capital and operating cost characteristics for each resource type and size. Generally speaking, the most cost-effective transmission-connected options for meeting local needs in the Niagara Region are resources with a performance and costs on par with simple cycle gas turbines. New natural gas-fired generation was considered in the economic analysis for illustrative purposes, as it was representative of the lowest cost generation option. Energy storage, such as lithium nickel manganese cobalt oxide batteries, are also becoming cost-competitive due to declining technology costs and the expectation of carbon prices increasing in line with federal policy. Other energy resources (which are typically distribution-connected) are also considered.

CDM measures can also help decrease the net electricity demand. Centrally delivered energy efficiency measures under the 2021-2024 CDM Framework and Save on Energy brand are already included in the load forecast, as discussed in the Section 5.4. As part of this current Framework, the IESO was directed to deliver a new program to address regional and/or local system needs. The Local Initiative Program is now one tool that is available to target the delivery of additional CDM savings at specific areas of the province with identified system needs. LDCs can also use the Ontario Energy Board's CDM Guidelines to leverage distribution rates to help address distribution and transmission system needs using non-wires alternatives.[8] Generally, incremental CDM measures are suitable for needs where growth is slow and the magnitude of the overload relative to the total demand is very small (i.e., on the order of few percent per year). These considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

For both wires and non-wires options, the upfront capital and operating are compiled to generate levelized annual capacity costs ($/kW-year). A cash flow of the levelized costs for the options are compared over the lifespan of the wires option (typically 70 years for transmission infrastructure). The non-wires options also include any system capacity benefit that they could contribute to provincial resource adequacy needs, ensuring that they are both sized to address the local need and are comparable to the wires options. The net present value (in 2021 CAD dollars) of these levelized costs are the primary basis through which feasible options are compared.

It is important to recognize that there is a significant error margin around costs estimates at the planning stage, as they are only intended to enable comparison between options during the IRRP. The RIP (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine wires cost estimates before implementation work begins. The IESO continues to participate in the Technical Working Group during the RIP and revisits these recommendations if costs estimates differ significantly. Furthermore, in cases where other barriers downstream of the regional planning process (i.e., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints) impede the adoption of some of these cost-effective options, pilot or demonstration projects can be explored.[9]

The list of assumptions made in the economic analysis can be found in Appendix F.

7.2 Screening Options

As explained in Section 7.1, an array of options can be developed to meet local needs during an IRRP, but options are ultimately evaluated to recommend the most cost-effective and technically

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[8] More information about the CDM Guidelines is available on the Ontario Energy Board's website.

[9] Barriers to non-wires alternatives and recommendations to address them were a part of the Regional Planning Process Review.

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 non-wires 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 21, and the results of its application to the Niagara IRRP needs are summarized in Table 4 and then further described in the sections below. More details on the steps and inputs used in the screening mechanism can be found in Appendix C.

Figure 21 | IRRP Screening Mechanism

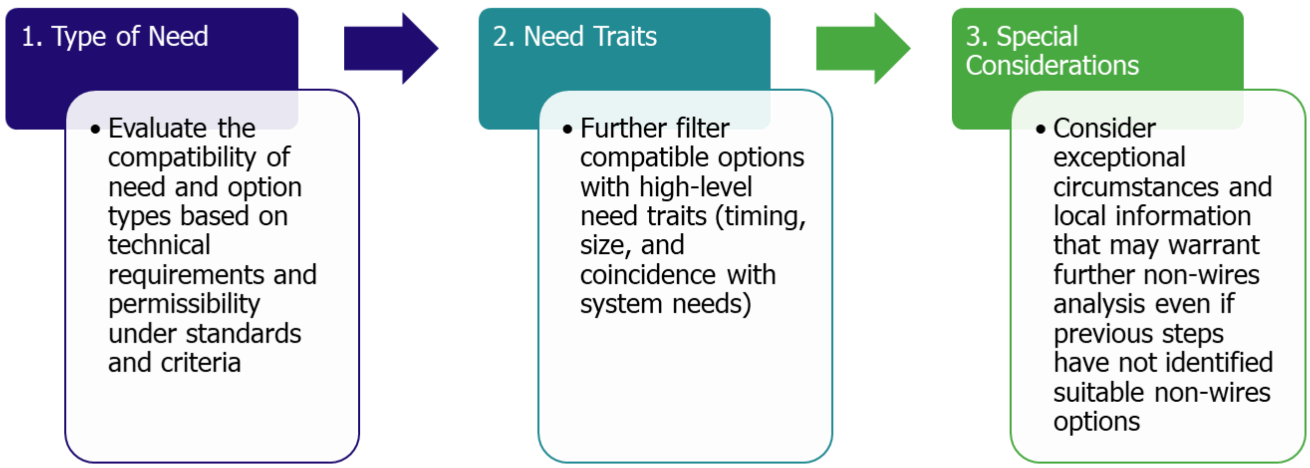

Table 4 | Results of Niagara IRRP Screening

Need Type	Impacted Element	Options Screened In	Options Screened Out
Station capacity	Beamsville TS	Wires, demand response ("DR"), DG, CDM	Transmission-connected generation
Station capacity	Vineland DS	Wires, CDM	Transmission-connected generation, DR, DG
Station capacity	Crowland TS	Wires, DR, DG, CDM	Transmission-connected generation
Station capacity	Kalar MTS	Wires, CDM	Transmission-connected generation, DR, DG
Station capacity	Carlton TS	Wires	All non-wires

Need Type	Impacted Element	Options Screened In	Options Screened Out
Station capacity	Murray TS (T11/T12)	Wires	All non-wires
Supply capacity	Niagara 115 kV sub-system	Wires, transmission-connected generation, CDM	DR, DG
Asset replacement	Crowland TS	Coordinated with the Crowland TS station capacity need	Coordinated with the Crowland TS station capacity need
Load security	Load supplied by A6C/A7C circuits	Wires	All non-wires

7.2.1 Non-Wires Options for the Capacity Needs

Based on the nature of the need, Step 1 of the screening mechanism identifies that 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 resources that are connected downstream of the limiting step-down transformer. The following sections outline when Steps 2 and 3 of the screening resulted in further analysis of non-wires options.

7.2.1.1 Beamsville TS, Niagara West MTS, and Vineland DS

As described previously in Section 6.2.1, there are forecast station capacity needs at Beamsville TS, Niagara West MTS, and Vineland DS, as well as a collective capacity shortfall in the area supplied by the three stations. Though eventually considered together given their geographic proximity, Beamsville TS and Vineland DS were screened independently. For Beamsville TS, with its large near-term capacity need, all applicable non-wires options were considered. Conversely, for the small long-term need at Vineland DS, the focus (in terms of a non-wires option) was on incremental CDM.

At the time of screening, the Technical Working Group did not identify a station capacity need at Niagara West MTS; this occurred later in the IRRP development when the forecast was updated by Grimsby Power. Hence, formal screening was not conducted for Niagara West MTS – but this IRRP does ultimately include recommendations that address its need (see Section 7.3).

7.2.1.2 Crowland TS

For Crowland TS, all applicable non-wires options were developed in further detail. Initially, at the time of the screening, the Crowland TS and Kalar MTS station needs were approached together given their perceived geographic proximity. However, recommendations were eventually made for these stations separately after considering factors that made an integrated approach impractical. These factors include distribution voltage level differences, distance to supply forecast growth areas, and misaligned capacity need timing between the two stations.

7.2.1.3 Carlton TS, Kalar MTS, and Murray TS (T11/T12)

For some needs, further analysis of non-wires is not warranted if there is the high potential for an inexpensive and simple wires alternative that maximizes the use of existing infrastructure. This can include load transfers or control actions that are sufficient to meet the need.

This was the case for the station capacity needs at Carlton TS and Murray TS (T11/T12). At the time of screening, Alectra Utilities indicated plans to reallocate some forecast demand at Carlton TS to a nearby station with additional capacity (Bunting TS). At Murray TS, NPEI is supplied by both T11/T12 and T13/T14. While forecast demand for T11/T12 exceeds its LTR, there is sufficient remaining capacity at T13/T14.[10] Managing the load distribution between the four transformers at Murray TS is expected to address the need at T11/T12.

For the small long-term need at Kalar MTS, incremental CDM was screened in for additional analysis.

7.2.1.4 Niagara 115 kV 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 Niagara 115 kV sub-system, the magnitude of the capacity need was large enough that the option development focused on transmission-connected generation or storage, with some consideration for additional locally targeted CDM.

Other non-wires options such as DR and DG were screened out from further analysis for a number of reasons. For instance, the connection of DG (regardless of fuel type) is subject to equipment limitations such as minimum loading, feeder capacity, station thermal capacity, and short circuit requirements. With an approximately 200 MW supply capacity need, the amount of incremental DG required would not be able to connect to a single transformer station in the Niagara Region, and would be unlikely to be accommodated, coordinated, and operated across multiple stations to meet the local supply constraint.[11] Recall that existing contracted DG output at peak was already accounted for during the development of the net demand forecast.

Similarly, DR was screened out due to the magnitude of the Niagara 115 kV supply capacity need. Though DR can be considered as a potential option to the extent that loads in the area can be curtailed during peak hours, the amount of DR that has historically been acquired for system capacity needs can help indicate this option's feasibility. For the 2021 summer obligation period in the capacity auction, approximately 20 MW of total capacity cleared for the Niagara zone. These past auction results provide context as to the scale of demand response that would be required to address the Niagara supply capacity need; this is unlikely to be achievable in the near-term. It is also worth noting that the Capacity Auction acquires resources designed to meet provincial adequacy rather than specific local or regional needs.

[10] Approximately 50 MW of remaining capacity is available at Murray TS (T13/T14) according to the IRRP reference planning forecast.

[11] For existing station DG connection availability, consider Hydro One's capacity evaluation tool for generation applicants.

7.2.2 Non-Wires Options for the Asset Replacement Needs

Outcomes of screening non-wires options for the Crowland TS asset replacement need were aligned with the screening outcomes for the Crowland TS incremental station capacity need (i.e., the capacity need that persists even if the station is replaced like-for-like).

7.2.3 Non-Wires Options for the Load Security Needs

Due to the nature of planning criteria outlined in ORTAC 7.2, non-wires options such as CDM and DG cannot be applied to load security needs because they usually do not enable uninterruptable power supply to customers in the event of transmission contingencies. While voluntary load loss such as DR could help address the intent of load security planning criteria, it is an option type currently procured through the provincial capacity auction. This implementation mechanism is not the optimal approach, as its current design does not include the monitoring of local adequacy nor permit immediate responses after specific local contingencies. For these reasons, non-wires options are typically screened out for load security needs unless there are exceptional circumstances identified during the IRRP development.

7.3 Options and Recommendations for Meeting the Beamsville TS, Niagara West MTS, and Vineland DS Needs

7.3.1 Transmission Options

Due to the geographic proximity of Beamsville TS, Niagara West MTS, and Vineland DS, integrated transmission options were developed to address the station capacity needs in a coordinated manner. Three options for additional station capacity for the area were considered:

1. The replacement of existing Niagara West MTS with new 2 x 75/125 MVA transformers;
2. The expansion of Niagara West MTS with two new 67 MVA transformer units; or
3. A new, separate 230 kV station supplied from Q23BM and Q25BM.

Option 1 was ruled out, given that there was no indication of asset replacement needs at the existing Niagara West MTS (resulting in stranded asset costs), plus the risk of reduced reliability expected when implementing the replacement. Option 2 was estimated to cost as little as $17M and require three years from the commitment date, whereas Option 3 was estimated to cost up to $40M (depending on the size of the transformers and implementer) and would take three to four years.[12]

Given the immediate need at Beamsville TS, the Technical Working Group also considered load transfer capabilities in the near-term. Beamsville TS and Niagara West MTS both supply Grimsby Power, NPEI, and Hydro One Distribution, while Vineland DS supplies only NPEI. At the time of this IRRP, Grimsby Power estimated the ability to transfer approximately 7 MW of NPEI's forecast load at Beamsville TS to Niagara West MTS. Beyond this amount, the Niagara West MTS station capacity need would arise sooner than already forecast. There is also some remaining capacity (approximately 4 MW) expected at Vineland DS.

[12] All cost estimates, unless otherwise specified, are net present values based on a levelized cash flow analysis rather than capital costs – see Appendix F. In this case, a capital cost estimate of $19M (+/-15%) was provided for Option 2 and $25M - $40M for Option 3.

7.3.2 Non-Wires Options

As explained in Section 7.2.1.1, non-wires options were screened in for additional evaluation for the Beamsville TS and Vineland DS needs.

For Beamsville TS, a number of measures were assessed – such as combinations of incremental targeted CDM with battery storage or gas generation.[13] The most cost-effective non-wires solution portfolio included incremental CDM (approximately 6 MW of additional savings by 2041), plus battery storage assumed to be installed in two phases (2025 and 2038) to match the need profile.[14] For Vineland DS, the incremental CDM potential was also calculated: approximately 2 MW of additional demand savings by 2041.

The net present value ("NPV") of the portfolio of non-wires options for both Beamsville TS and Vineland TS was calculated to be $30M - $57M. The lower cost assumed that the incremental CDM is already system cost-effective based on provincial resource adequacy, whereas the higher cost assumed that the demand savings targeted to these stations would be incremental to the provincial CDM framework. More details on the CDM potential methodology and results are provided in Appendix E.

7.3.3 Recommendation

During the development of the IRRP, the forecasts at Beamsville TS and Niagara West MTS were updated by the impacted LDCs as growth trended higher and new potential customers were identified. By the conclusion of the IRRP, this reinforced the preference for the integrated wires options due to their cost-effectiveness and ability to address the capacity needs at all three stations.

The original scope of the non-wires options that were developed only addressed the Beamsville TS and Vineland DS needs, but were collectively $13M – $40M more expensive than the least expensive wires option. The increased forecast for Niagara West MTS did not impact the wires option of a new 230 kV station in the area – it only increased its cost-effectiveness. Another portfolio of non-wires options sized for Niagara West MTS' final reference forecast capacity need would have increased the non-wires costs further. Reallocating the load forecast on the 115 kV stations to 230 kV supply also helps alleviate the broader Niagara 115 kV sub-system capacity need.

Therefore, due to the cost-effectiveness and ability to meet the multiple needs, the Technical Working Group recommends near-term load transfers to offload Beamsville TS, plus a new 230 kV station supplied from Q23BM and Q25BM. This could be accomplished by expanding the existing Niagara West MTS. The station should be in-service as soon as possible and accommodate at least 57 MW of pre-contingency load in the area by 2041.

It is recommended that after the IRRP, the impacted LDCs coordinate the magnitude and timing of load transfers between the three stations to manage and monitor the Beamsville TS capacity need until the new station is in-service. Moreover, the LDCs and Hydro One should coordinate during the RIP to establish the lead implementer of the new station. Timing, siting, and size of the new

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[13] Based on the unserved energy profile forecast at Beamsville TS, the gas generator option was assumed to be a simple cycle gas turbine facility.

[14] This included an 18 MW, 144 MWh battery storage facility. The Beamsville TS forecast was updated and increased near the end of the IRRP forecast; cost range estimate would only increase with larger battery storage.

transformers should be factored into the decision – in addition to a comprehensive economic comparison that accounts for both the cost of the transformer station and the distribution-level costs that could incur if the station is sited farther west and away from the service territories that are expected to grow.

7.4 Options and Recommendations for Meeting the Crowland TS, Load Security, and Niagara 115 kV Sub-System Needs

The Crowland station capacity and asset replacement needs, as well as the A6C/A7C load security and Niagara 115 kV sub-system capacity needs, share common transmission elements and impact each other. As such, both wires and non-wires options were developed to address these four needs in an integrated fashion.

7.4.1 Transmission Options

Two sets of transmission options were identified – one that largely involves the continued buildout of the 115 kV system in the Niagara Region, and another that expands the 230 kV supply.

Option Set 1 includes:

- New 115 kV station in Welland, supplied by the existing A6C/A7C circuits (to address the Crowland TS capacity need);
- New 230 kV Allanburg bus (to improve supply to the 115 kV sub-system and mitigate the A6C/A7C load security need); and
- Re-building of 115 kV Crowland TS like-for-like (to address the asset replacement need).

Option Set 2 includes:

- Replacement of sections of 115 kV D3A/A3C circuits with approximately 18 km of new 230 kV double-circuit supply lines tapping off Q24HM and Q29HM; and
- The replacement of Crowland TS with a 230 kV station (to address its asset replacement and capacity needs, offload the Niagara 115 kV sub-system, and mitigate the A6C/A7C load security need).

In terms of preliminary capital costs, Option Set 1 was estimated to be approximately $253M - $353M[15] in total, whereas Option Set 2 may cost $128M.[16] Option Set 1 will require a minimum of three years; Option Set 2 will need six years.

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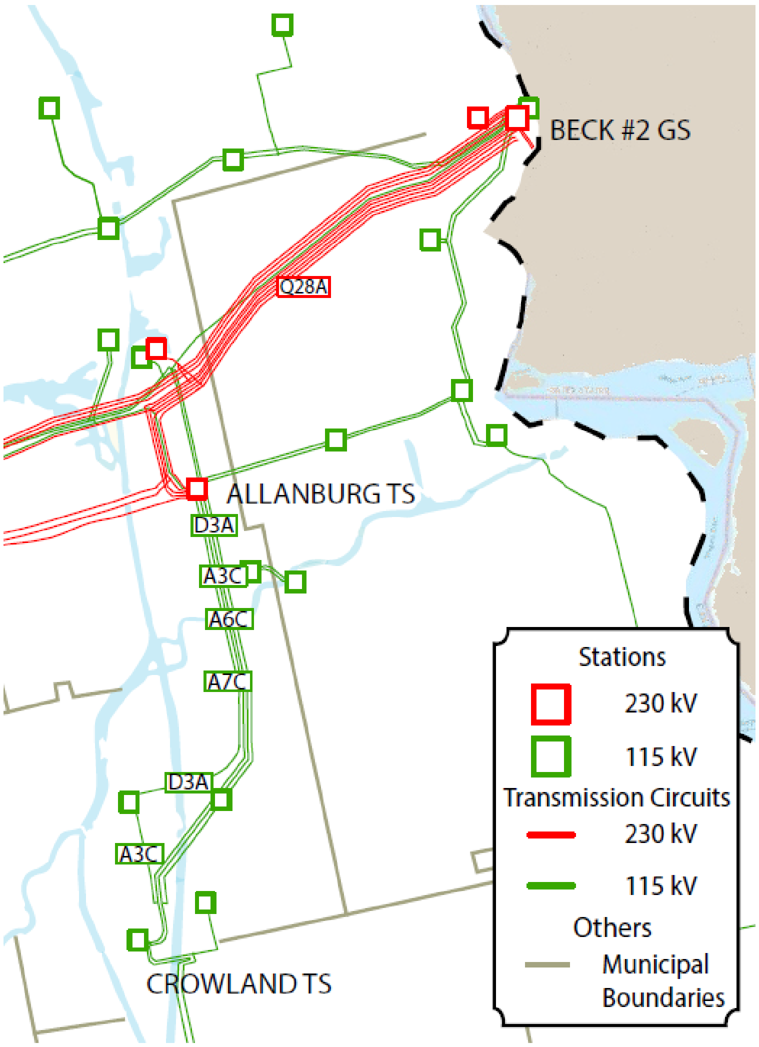
[15] The high end of the cost estimate range for Option Set 1 includes the potential for new 115 kV circuits and other reinforcements if the existing A6C/A7C circuits cannot accommodate the new 115 kV station in Welland.

[16] Capital cost estimates provided by Hydro One during the IRRP were prepared based on preliminary information and intended to provide a ballpark figure to be used strictly for initial options comparison. No engineering or field work was completed as part of the development of these cost allowances and as such, these cost allowances provide no cost guarantee or accuracy range. Costs allocations were derived from previous historical costs/unit costs and were to be used strictly for options comparison; Hydro One may refine and update cost estimates as part of the RIP.

To accommodate the planning forecast, the uprating of an existing 230 kV circuit, Q28A, is also required in addition to either Option Set. The cost and feasibility of this reinforcement is currently being assessed by Hydro One and is estimated to require until at least 2024 to be in-service.

The components of these Option Sets are identified conceptually on the map of Niagara Region's existing transmission system in Figure 22.

Figure 22 | Impacted Areas by the Transmission Options



Under some of the contingencies and conditions expected to limit the 115 kV sub-system LMC, operational measures such as load rejection are permissible according to ORTAC. Therefore, the benefit of a new load rejection scheme was also factored in when assessing the supply capability with each of the wires options described above. It was assumed that this scheme, developed and implemented by Hydro One for the Niagara 115 kV sub-system, could be installed in 2024 or later.[17]

[17] The ultimate in-service date will depend on the complexity of the scheme's design and NPCC approval timelines.

7.4.2 Non-Wires Options

As explained in Section 7.2.1.2 and 7.2.1.4, non-wires options were screened in for additional evaluation for the Crowland TS and 115 kV sub-system supply needs.

For the Crowland TS capacity need alone, incremental targeted CDM, battery storage, and gas generation were all considered either as standalone or integrated options.[18] The most cost-effective non-wires solution portfolio for the Crowland capacity need included incremental CDM (approximately 10 MW of additional savings by 2041), plus a 10 MW/40 MWh battery storage facility installed in two phases (2025 and 2038) to match the need profile. The NPV of this portfolio was calculated to be in the range of $17M - $53M. Similar to what was described for the Beamsville TS non-wires options, this cost range is attributed to the provincial CDM assumptions.[19]

As the Niagara IRRP progressed and the interplay between the Crowland TS needs and the broader Niagara 115 kV supply capability became clearer, a non-wires option was also considered at a high level. An all-generation, 240 MW alternative was sized to compare to the lowest cost transmission option set; 240 MW is the expected increase in the 115 kV sub-system supply capability enabled by Option Set 2 described previously. However, this non-wires option is not a feasible solution due to various factors. While an all-generation option was identified to compare to the wires option on a MW basis, there are significant challenges to implementing and operating a resource to address the multiple, layered, and local needs. For instance, for 240 MW of generation to address both the Crowland TS capacity and replacement needs, as well as the broader 115 kV supply needs, a portion of the generation must be sited on the distribution system to supply customers currently served by Crowland TS and the remaining must be targeted to the region's 115 kV system. There may also be thermal or short circuit limitations to connecting this amount of generation on the distribution system. Moreover, as described in Section 7.2.3, generation is typically not considered a feasible option to solve load security needs.

7.4.3 Recommendation

When comparing the two wires option sets, Option Set 2 is preferred for a number of reasons. It is the more cost-effective option, evaluated at more than $100M less expensive than Option Set 1 (based on capital cost estimates), even though both offer similar 115 kV sub-system supply capability and are sufficient according to the reference planning forecast. Qualitatively, by expanding the 230 kV transmission system, Option Set 2 also offers long-term flexibility to accommodate more load growth in the southern portion of the Niagara Region – particularly along the industrial and commercial hub around the Welland Canal. Option Set 1 provides limited growth options in the area in comparison to Option Set 2, without extensive station expansion at Allanburg TS. Meanwhile, converting the existing 115 kV Crowland TS to 230 kV in Option Set 2 allows the other 115 kV stations in the Niagara Region to accommodate new growth and maximizes the use of existing infrastructure with the available capacity normally utilized by the 115 kV Crowland TS. Triggering the

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[18] Based on the unserved energy profile forecast at Crowland TS, the gas generator option was assumed to be a simple cycle gas turbine facility.

[19] Another sensitivity was conducted for the battery storage sizing, resulting in a higher cost range of $25M - $61M. See Appendix D.3 for more details.

reconfiguration is also a time-sensitive opportunity, since Crowland TS is expected to require asset replacement in the near term.[20]

Long-term flexibility can also be considered by comparing the options and their ability to accommodate the high IRRP forecast scenario. According to the reference forecast, approximately 200 MW of extra 115 kV supply capability is required by 2041. As shown in Section 6.3, the high scenario increased this requirement to 340 MW. Both Option Sets 1 and 2 enable the increased capability required for the reference forecast, and neither Option Set precludes a further wires or non-wires option in the long-term. These future actions can include new generation resources or additional 230/115 kV auto-transformation. In contrast, a non-wires option sized precisely to meet the reference need would have less flexibility to accommodate growth that exceeds today's expectations.

Regardless, none of the non-wires options described in Section 7.4.2 can sufficiently address the multiple needs at once. Wires Option Set 2 would cost-effectively resolve the Crowland capacity and replacement needs, the A6C/A7C security issue, and enable other load growth on the 115 kV sub-system. For these reasons, the Technical Working Group recommends the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM/Q29HM, as well as the uprating of Q28A. A new load rejection scheme should also be developed to manage the Niagara 115 kV sub-system need. The load forecast should be monitored between regional planning cycles, and there are benefits to targeting incremental CDM to the 115 kV sub-system in order to manage load growth beyond the reference scenario. The technical feasibility and costs of the wires recommendations should be further analyzed in the RIP; the IESO will continue to participate in the RIP Working Group to provide advice and input on this matter.

7.5 Summary of Recommended Actions and Next Steps

The Technical Working Group recommends the actions summarized in Table 5 to meet identified needs in the Niagara IRRP.

Table 5 | Summary of Needs and Recommended Actions

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Coordinate load transfers to offload Beamsville TS to Niagara West MTS in the near-term	• 2023

[20] All final cost estimates have accounted for the asset replacement value for Crowland TS.

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity • Niagara 115 kV sub-system supply capacity	• Grimsby Power • NPEI • Hydro One Distribution • Hydro One Transmission	• Initiate development for a new 230 kV station supplied from Q23BM and Q25BM, or an expansion of Niagara West MTS	• 2026-2027
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Monitor load growth between regional planning cycles	• Ongoing
• Beamsville TS and Vineland DS station capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to Beamsville TS and Vineland DS	• Ongoing
• Crowland TS station capacity and asset replacement • A6C/A7C load security • Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Initiate development for the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM and Q29HM	• 2028
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Develop and implement a new 115 kV sub-system load rejection scheme	• 2024
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Uprate Q28A	• 2024
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Monitor load growth between regional planning cycles	• Ongoing

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to the 115 kV sub-system	• Ongoing
• Murray TS (T11/T12) station capacity	• NPEI • Hydro One Transmission	• Transfer load in excess of the station limit to Murray TS T13/T14	• 2023
• Carlton TS station capacity	• Alectra	• Monitor load growth between regional planning cycles • Transfer load in excess of the station limit to Bunting TS	• 2028
• Kalar MTS station capacity	• NPEI	• Monitor load growth between regional planning cycles and consider future opportunities for incremental CDM	• 2030

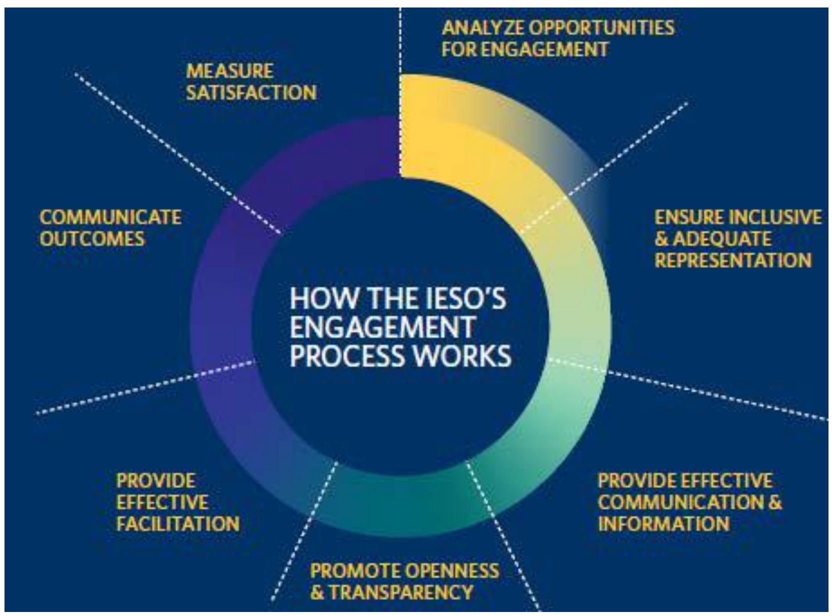
8. Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Niagara IRRP.

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. The IESO uses these principles to ensure inclusiveness, sincerity, respect, and fairness in its engagements, striving to build trusting relationships as a result.

Figure 23 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Niagara Region

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.

Creating the engagement plan for this IRRP involved:

- Targeted discussions to help inform the engagement approach for this 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 in 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 the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars; and
- Targeted one-on-one outreach with specific communities and stakeholders to ensure that their identified needs are addressed (see Section 8.4).

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this second round of planning, and to establish new relationships and dialogue in this region where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report for the Niagara 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 planning cycle and invite interested parties to provide input on the Niagara Region Scoping Assessment Report finalization. A public webinar was held in August 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, identifying the need for a coordinated regional planning approach and an IRRP.

Following finalizing the Scoping Assessment, targeted outreach then began with municipalities in the region to inform early discussions for development of the IRRP, including the IESO's approach to engagement. The launch of a broader engagement initiative followed, with an invitation to IESO subscribers of the Niagara Region to ensure that all interested parties 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 its 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 after each webinar.

The three stages of engagement at which input was invited:

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.

Comments received during this engagement were primarily focused on:

- Ensuring key areas of growth in specific pockets in the Niagara Region (including the City of Niagara Falls and Town of Fort Erie), have been considered and accounted for in the IRRP work;
- Ensuring there are procedures to alter the implementation of plan recommendations should changes occur in the region; and
- Keeping lines of communication following the plan completion to share information and updates.

Feedback received during the written comment periods for these webinars helped to guide further discussions 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 Niagara Region subscribers, municipalities, and Indigenous and Métis communities.

Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP and recommended actions aligned with strong forecast growth and development both within specific municipalities and the region more broadly (e.g. future urban expansion and employment areas as outlined in the updated Niagara Region Official Plan). This insight has been valuable to the IESO – it supported an understanding of local growth and an accurate electricity demand forecast, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply. To that end, ongoing discussions will continue through the IESO's Southwest Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and initiatives to prepare for the next planning cycle.

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

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with the upper- and lower-tier municipalities in the region to discuss key issues of concern, including forecast regional electricity needs, options for meeting the region's future needs, and broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities, establish new relationships, and provided opportunities for ongoing dialogue beyond this IRRP process.

Through these discussions valuable feedback was received around strong anticipated growth in major growth centres in the region:

- Strong population growth across the Niagara Region based on 2051 growth projections and in some areas above and beyond the regional forecast (i.e. even higher growth expected in the City of Welland);
- Notable growth in the Town of Lincoln (greenhouses, Secondary Plan areas, potential GO Transit development), along the QEW corridor in Grimsby, and in Thorold;

- Strong economic development around the Welland Canal (e.g. Thorold Multimodal Hub "Niagara Ports");
- Key areas of growth in the City of Niagara Falls within intensification nodes and corridors, projects around the GO Transit Station and the new Niagara South Hospital, wastewater treatment plant, and residential new construction;
- Industrial, commercial, institutional, and residential development in the Town of Fort Erie and Secondary Plan areas; and
- Potential urban boundary expansion in the region totaling 130 hectares of residential and 150 hectares of employment lands.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Niagara Region throughout the development of the plan. This includes the communities of the Mississaugas of the New Credit, Oneida Nation of the Thames and Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council) and Métis Nation of Ontario Niagara Region Métis Council.

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions all across Ontario.

9. Conclusion

The Niagara IRRP identifies electricity needs in the region over the 20-year period from 2022 to 2041, 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 load transfers off Beamsville TS and a new or expanded 230 kV station supplied by Q23BM and Q25BM. The IRRP also recommends the implementation of control actions on the Niagara 115 kV sub-system to manage overloads during outage conditions, plus the replacement of Crowland TS with a new 230 kV station supplied by new 230 kV lines from Q24HM and Q29HM. Q28A should be uprated, and a portion of the load at Murray TS (T11/T12) should be transferred to Murray TS (T13/T14). 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 monitor growth in the Niagara 115 kV sub-system, Carlton TS, and Kalar MTS to determine if or when further reinforcements will be needed. This includes monitoring any future community energy planning or electrification trends. Additionally, there are benefits to investigating opportunities to target incremental CDM to the region – particularly to the Beamsville TS/Vineland DS/Niagara West MTS areas and 115 kV sub-system in the near-term, and Kalar MTS in the long-term.

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.