Renfrew Region Integrated Regional Resource Plan

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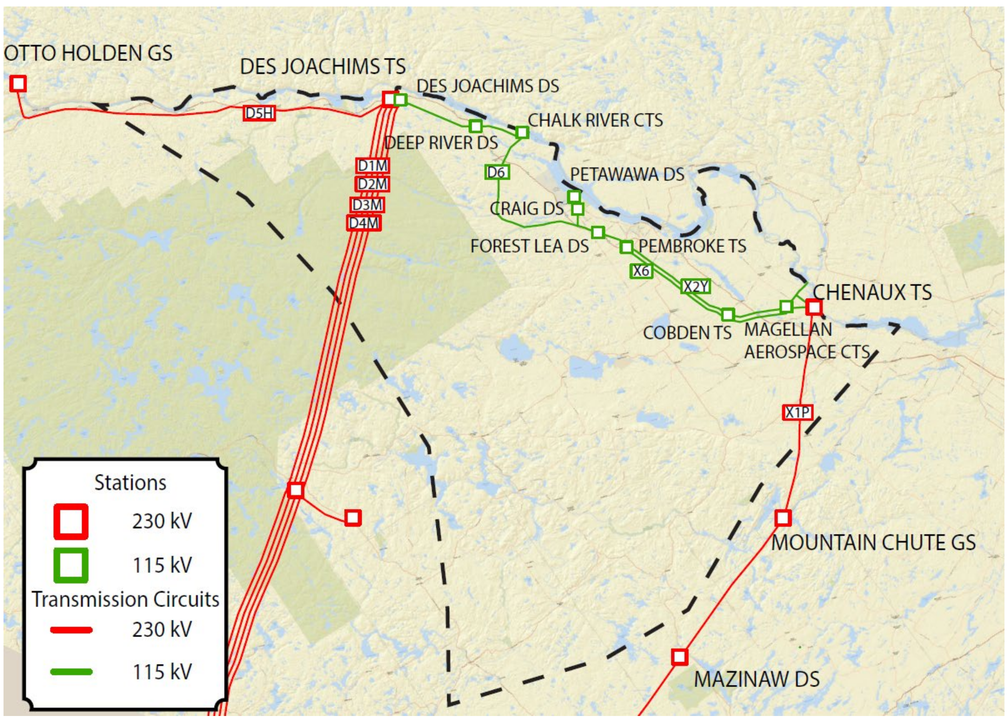
List of Acronyms

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

1. Introduction

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

Figure 1 | Renfrew Region Map



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

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

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

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

The report is organized as follows:

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

2. The Integrated Regional Resource Plan

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

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

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

2.1 Near- to Medium- Term Plan

Recommended Actions

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

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

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

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

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

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

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

2.2 Long- Term Plan

Recommended Actions

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

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

3. Development of the Plan

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

The process consists of four main components:

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

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

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

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

3.1 Renfrew IRRP Development

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

4. Background and Region Overview

4.1 Region Overview

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

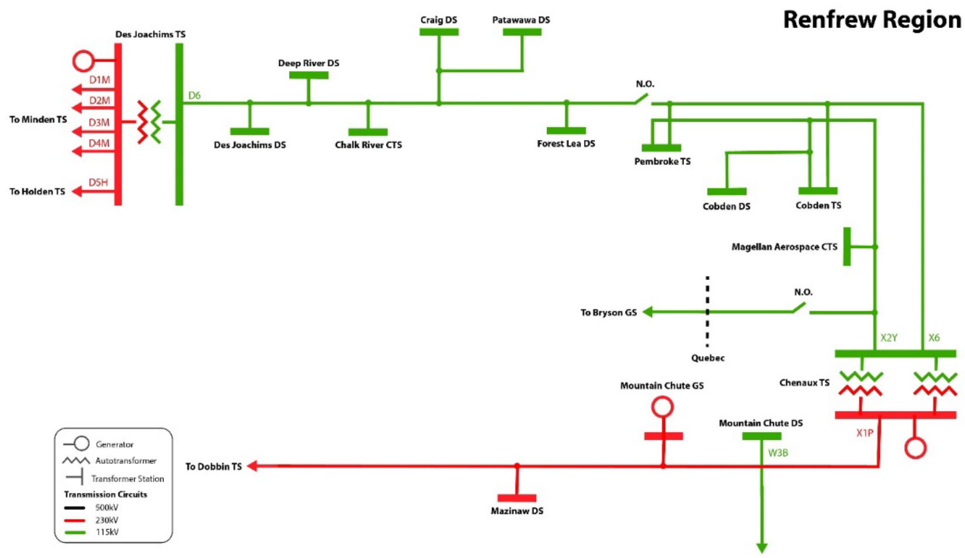
Hydro One Distribution is the main LDC for the region with Ottawa River Power Corp. embedded at Pembroke TS. ORPC is responsible for managing the distribution system for the central Pembroke area. The Hydro One portion of the station is predominantly industrial based. The ORPC portion of the load is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

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

4.2 Electrical System

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

Figure 2 | Single Line Diagram of Renfrew Electric System



4.3 Previous Planning Activities

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

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

4.4 Scope of Work

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

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

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

5. Electricity Demand Forecast

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

5.1 Demand Forecast Methodology

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

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

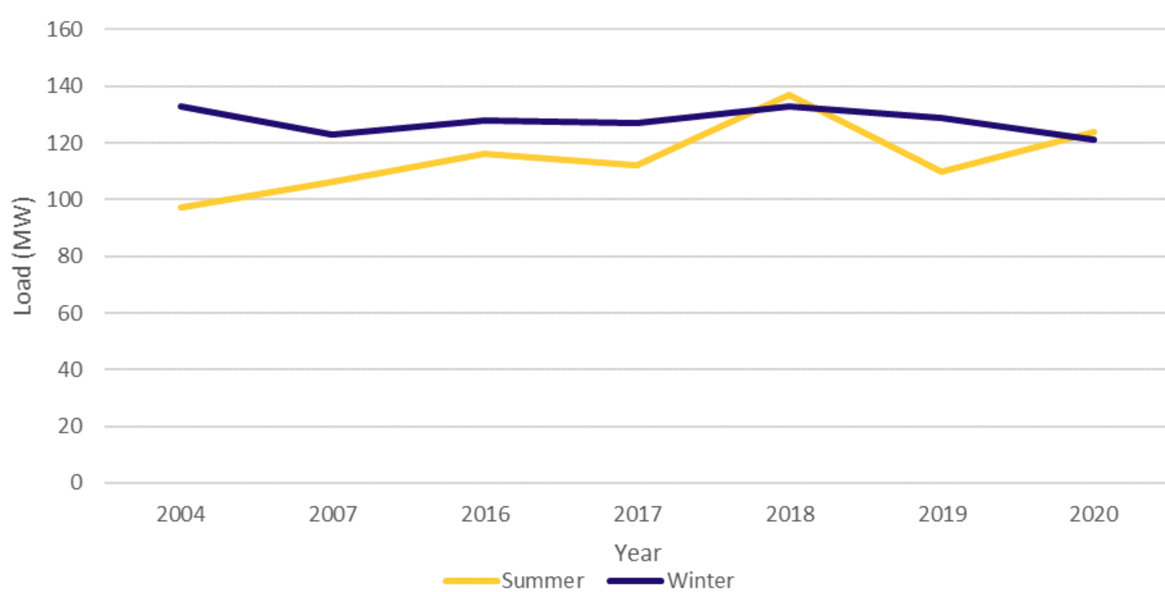
The process of developing the planning forecast starts with the development of the starting points. These consider several factors including historical load, weather, and generation at each of the stations. Using these starting points, distributors develop a 20-year gross demand forecast by accounting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

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

5.2 Historical Electricity Demand

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

Figure 3 | Renfrew Historical Coincident Demand



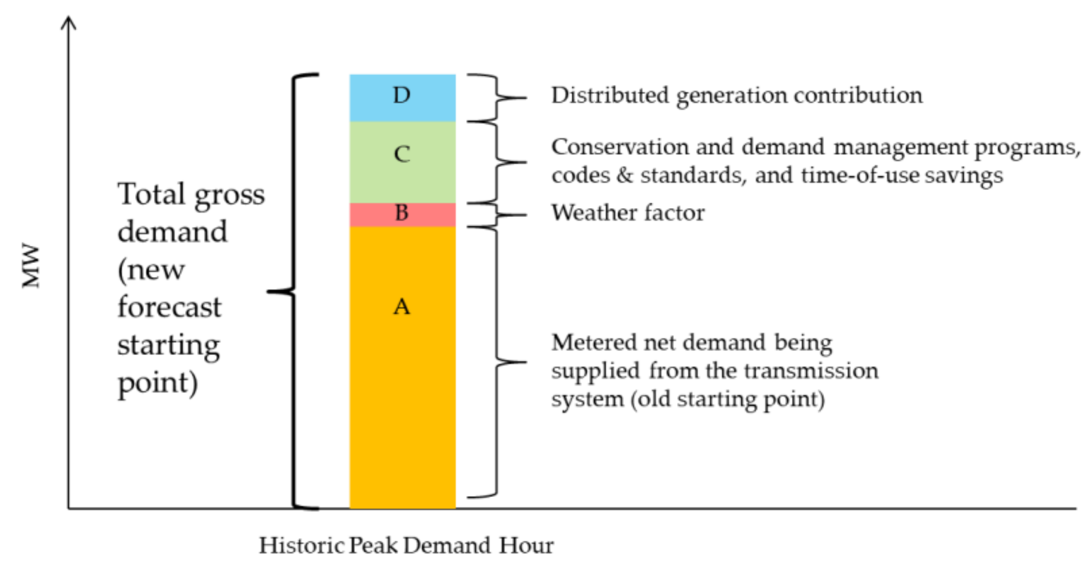
Based on the historical trend it is might be thought that the next twenty years will continue to see little to no growth. However, it is precisely the summer forecast's gradual increase that is telling of trends that could have a significant effect. The ratings of the power system electrical equipment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

5.3 Gross Demand Forecast Starting Point

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

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

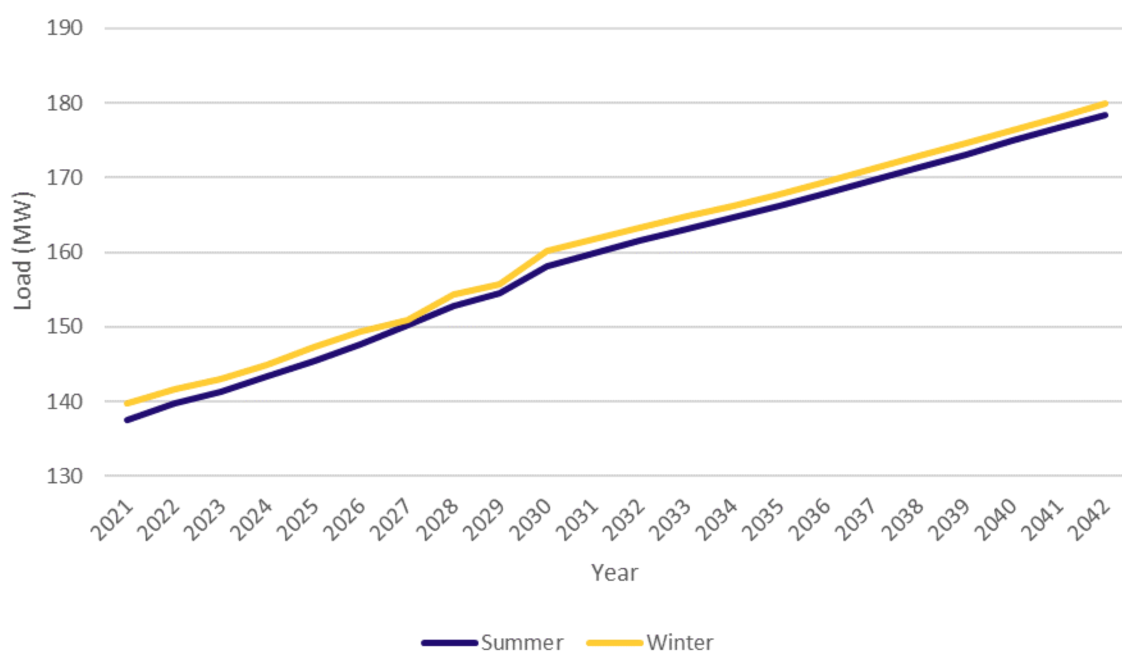
Figure 4 | Load Unbundling to Establish a Gross Demand Starting Point for Forecasting



5.4 Gross Demand Forecast

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

Figure 5 | Renfrew Region Non-Coincident Gross Median Demand



5.5 Contribution of Conservation on Forecast

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

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

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

Table 1 | MW Savings from Conservation and Demand Management

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

5.6 Contribution of Distributed Generation on Forecast

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

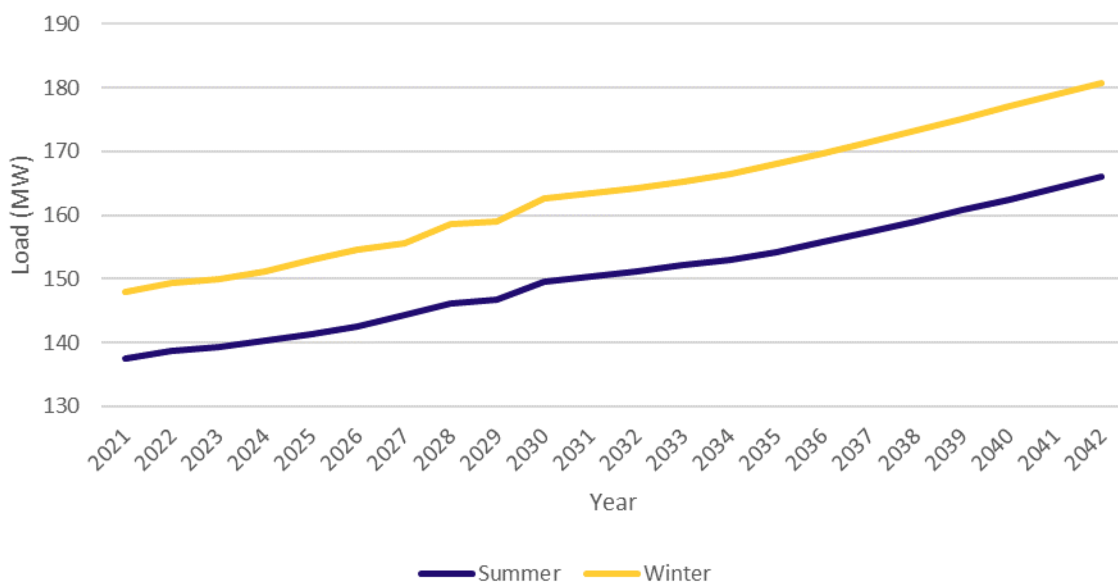
The effective capacity, i.e., the MW output at the time of regional peak, was determined at a resource level, and the data was aggregated at a station level in order to put together a forecast specifying the estimated peak demand reduction due to DG output. From 2021 to 2042, the expected annual peak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

- Deep River
- Des Joachims
- Cobden
- Pembroke

5.7 Planning Demand Forecast

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

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



5.8 Sensitivity Scenario: Higher Growth Forecast

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

5.9 Hourly Forecast Profiles

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

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

6. Transmission System Issues

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

6.1 Transmission System Issues Methodology

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

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

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

6.2 Near- to Medium-Term Needs

6.2.1 Station Capacity Issues

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

6.2.1.1 Pembroke TS Capacity Issue

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

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

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

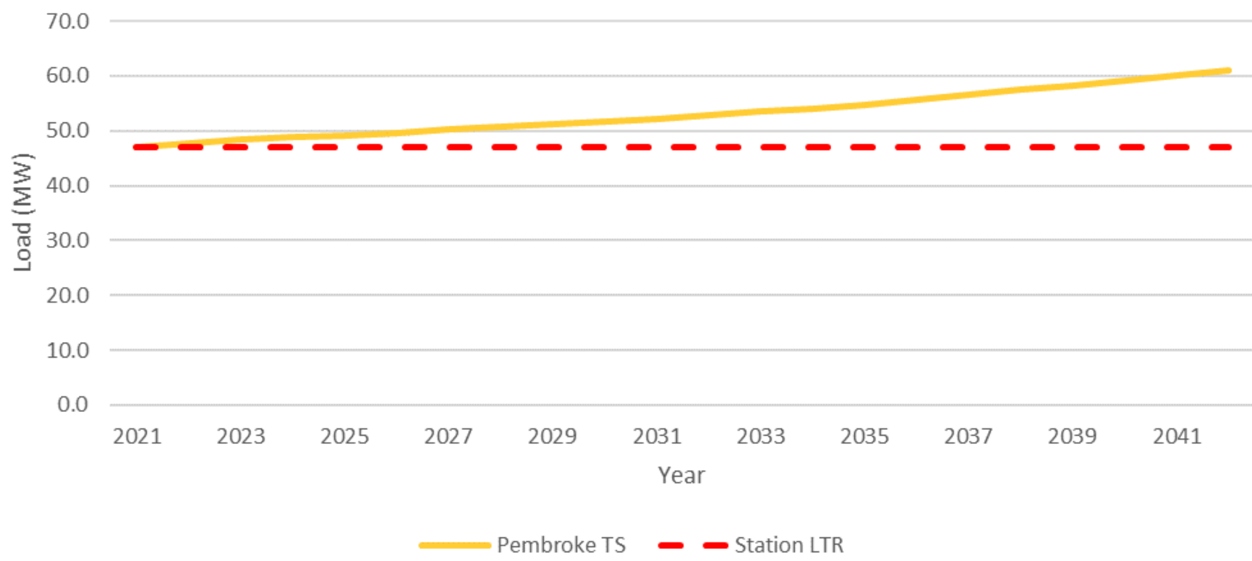
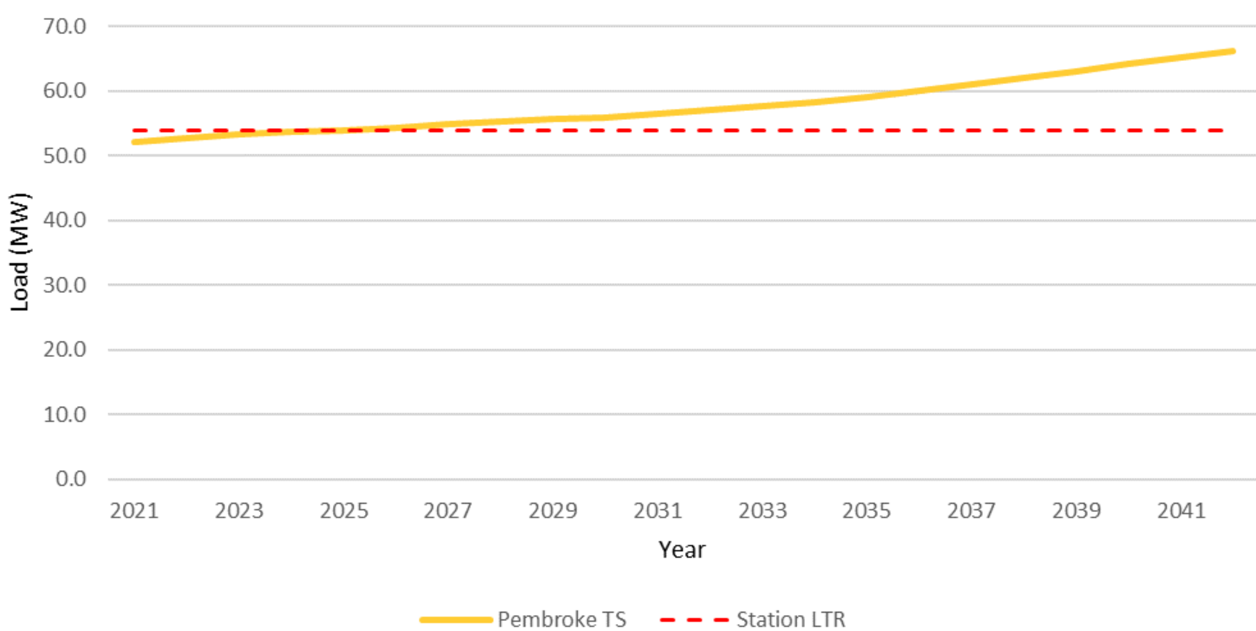


Figure 8 | Winter Non-Coincident Demand Forecast for Pembroke TS



6.2.1.2 Forest Lea DS Capacity Issue

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

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

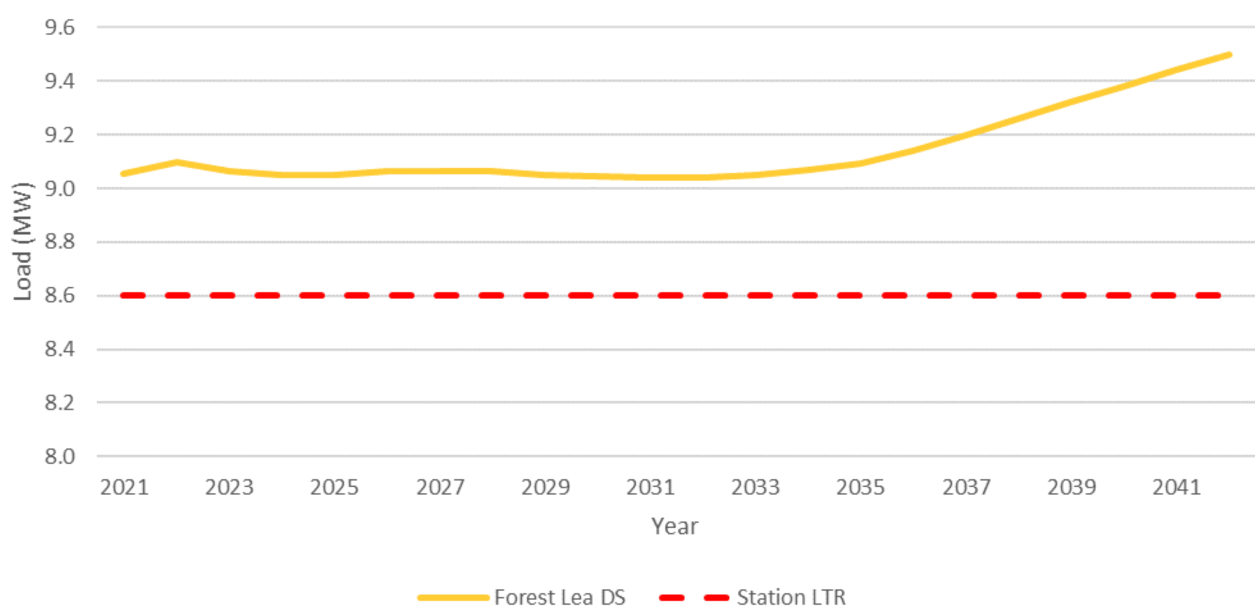
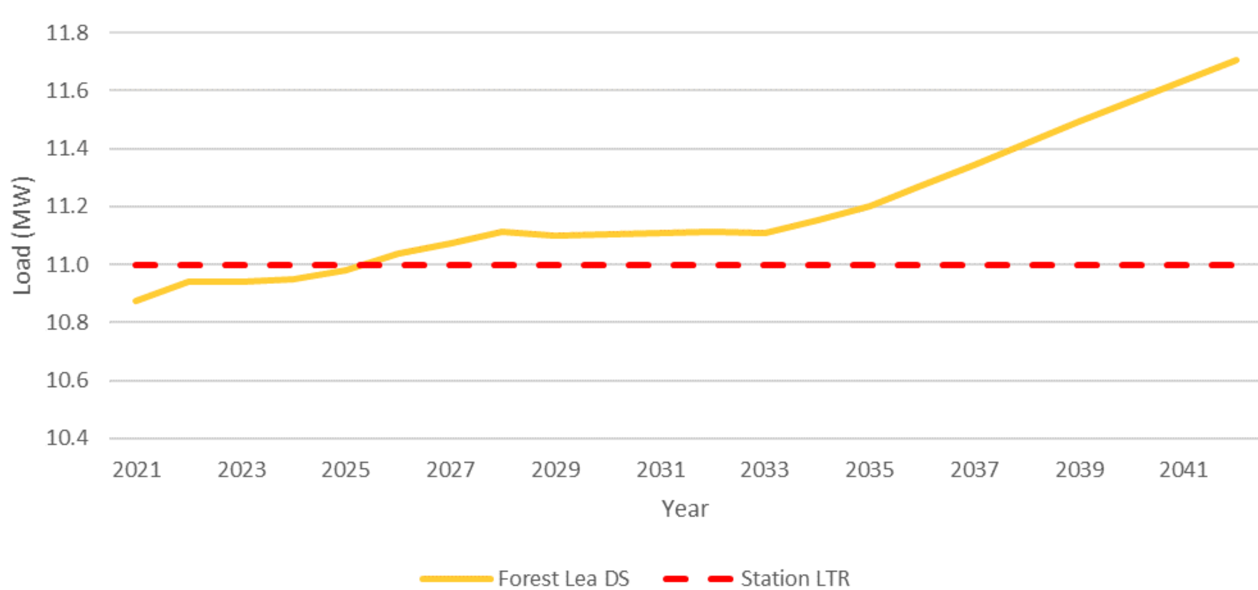


Figure 10 | Winter Non-Coincident Demand Forecast for Forest Lea DS



6.2.1.3 Petawawa DS Capacity Issue

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

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

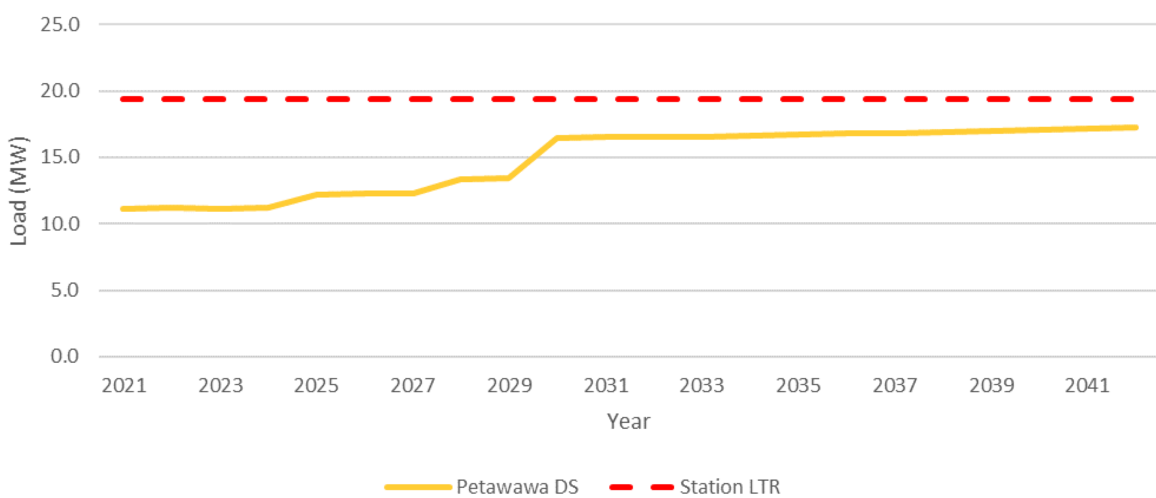
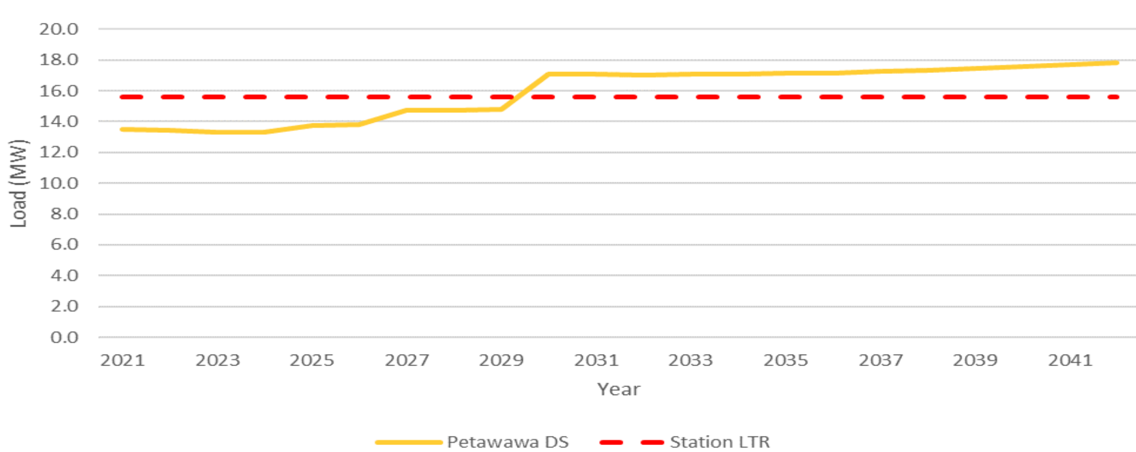


Figure 12 | Winter Non-Coincident Demand Forecast for Petawawa DS



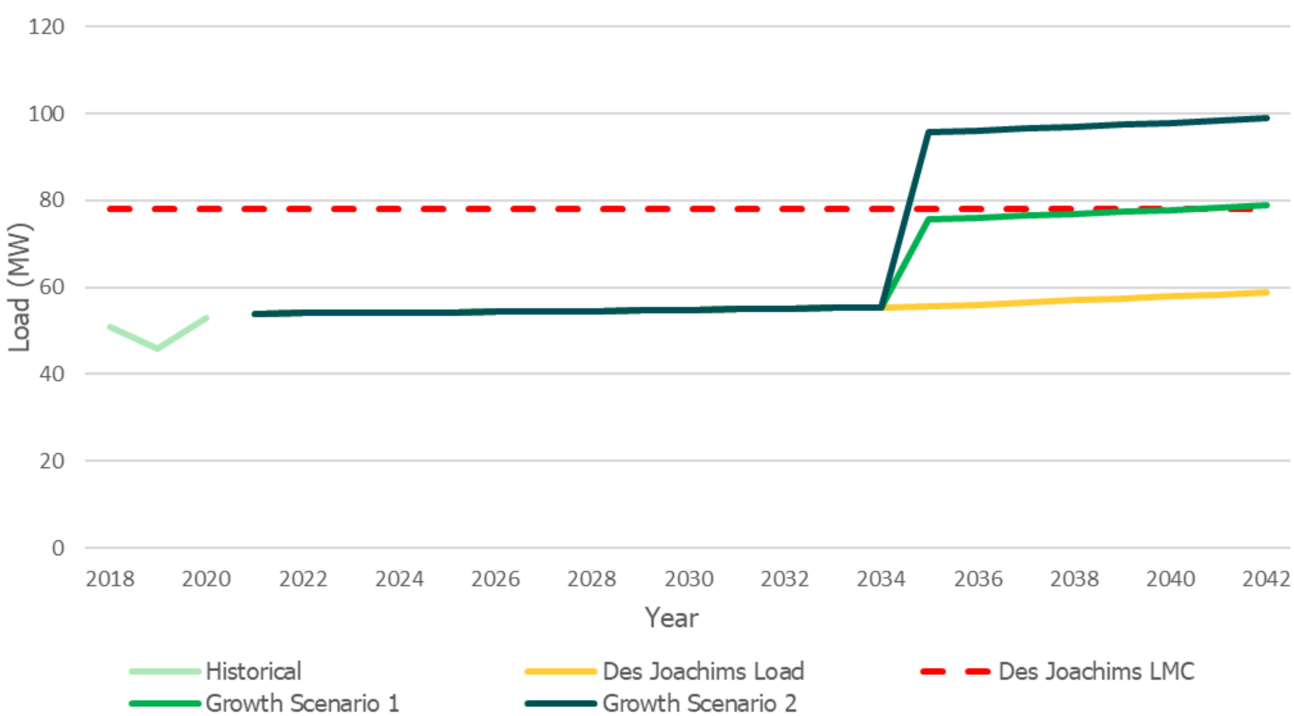
6.3 Long-Term Needs

6.3.1 Supply Capacity Issues

6.3.1.1 Des Joachims Sub-System Capacity Issue

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

Figure 13 | Des Joachims Side Summer Coincident Load Forecast



7. Options and Recommendations

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

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

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

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

7.1 Options Considered in IRRPs

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

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

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

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

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

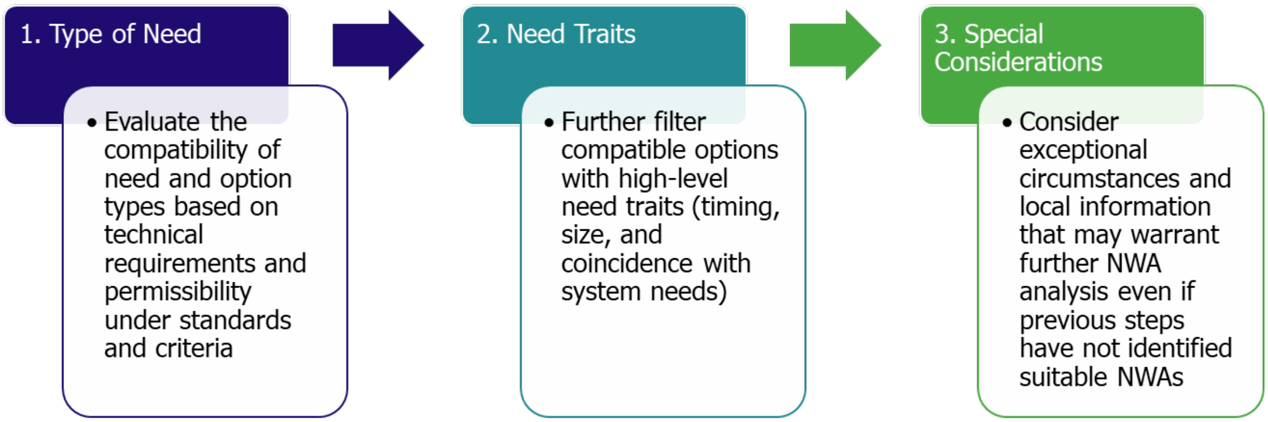
Both the upfront capital and operating cost of the wires options, generation, and distributed energy resources are compiled to generate levelized annual capacity costs ($/kW-yr) over the lifespan of the asset in question (for Renfrew a 45-year lifespan is assumed for the station infrastructure) for each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

7.2 Screening Options

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

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

Figure 14 | IRRP Screening Mechanism



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

7.2.1 Non-Wires Options for the Capacity Needs

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

7.2.1.1 Pembroke TS

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

7.2.1.2 Petawawa DS

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

7.2.1.3 Forest Lea DS

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

7.2.1.4 Des Joachims Sub-System Supply

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

7.2.1.5 Summary of Screening Outcomes

Table 2 | Results of Renfrew IRRP Screening

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

7.3 Options for Meeting Near- to Medium-Term Issues

7.3.1 Options for Meeting Pembroke TS Station Capacity Need

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

7.3.1.1 Transmission Options

Two feasible wires options were considered:

- Building a new HVDS, or
- Building a new DESN station, or “TS”.

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

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

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

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

7.3.1.2 Non-wires Options

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

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

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

7.3.1.3 Recommendations

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

7.3.2 Options for Meeting Petawawa DS Station Capacity Need

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

7.3.2.1 Transmission Options

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

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

7.3.2.1 Non-wires Options

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

7.3.2.3 Recommendations

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

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

7.3.3 Options for Meeting Forest Lea DS Station Capacity Need

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

7.3.3.1 Transmission Options

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

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

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

7.3.3.2 Non-wires Options

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

7.3.3.2 Recommendations

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

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

7.4 Options for Meeting Long-Term Issues

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

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

7.4.1.1 Transmission Options

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

7.4.1.2 Recommendations

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

7.5 Summary of Actions and Next Steps

Table 3 | Summary of Actions and Next Steps

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

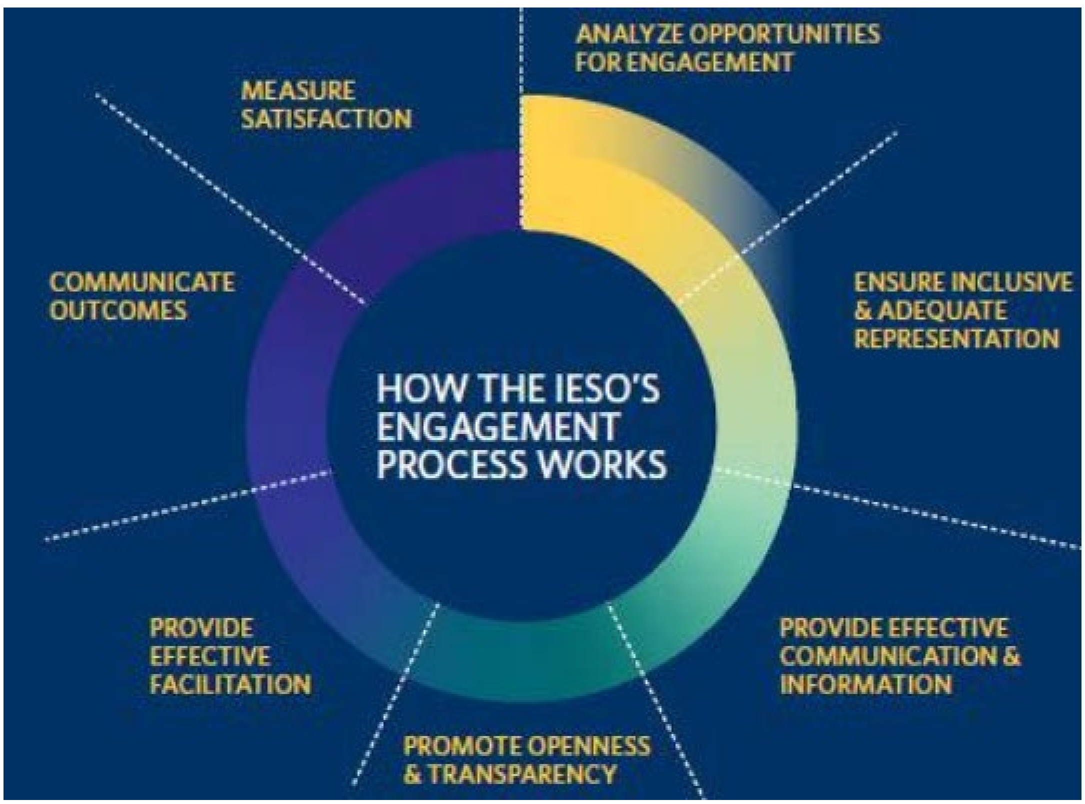
8. Engagement

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

8.1 Engagement Principles

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

Figure 15 | IESO's Engagement Principles



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

8.2 Developing an Engagement Plan for Renfrew

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

Creating the engagement plan for this IRRP involved:

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

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

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

8.3 Engage Early and Often

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

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

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

The three stages of engagement invited input on:

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

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

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

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

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

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

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

8.4 Bringing Municipalities to the Table

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

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

8.5 Engaging with Indigenous Communities

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

Indigenous Participation and Engagement in Transmission Development

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

As part of the overall transmission development process, a proponent applies for applicable regulatory approvals, including an Environmental Assessment that is overseen by the Ministry of Environment, Conservation and Parks (MECP). This process includes, where applicable, consultation regarding Aboriginal and treaty rights, with any approval including steps to avoid or mitigate impacts to said rights. MECP oversees the consultation process generally but may delegate the procedural aspects of consultation to the proponent. Following development work, the proponent will then need to apply to the OEB for approval through a Leave to Construct hearing, and only if approval is granted, can it proceed with the project. In consultation with MECP, project proponents are encouraged to engage with Indigenous communities on ways to enable participation in these projects.

9. Conclusion

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

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

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

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

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