Windsor-Essex Integrated Regional Resource Plan

Appendices

April 3, 2025

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Powering Tomorrow.

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Table of Contents

List of Figures

List of Tables

List of Acronyms

BESS	Battery Energy Storage System
eDSM	Electricity Demand Side Management
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual-Element Spot Network
DG	Distributed Generation
DS	Distribution Station
FIT	Feed-in-Tariff
GR	Generation Rejection
HPS	High Pressure Sodium
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
LDC	Local Distribution Company
LED	Light Emitting Diode
LTE	Long-term emergency
kV	kilovolt
LMC	Load Meeting Capability
LR	Load Rejection
LTR	Limited Time Rating
MTS	Municipal Transformer Station
MW	Megawatt
NCCI	New Customer Connection Information
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NWA	Non-Wires Alternative
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RAS	Remedial Action Scheme
RIP	Regional Infrastructure Plan
SMR	South Middle Road
STE	Short-term emergency
TS	Transformer Station
TWG	Technical Working Group
ULTC	Under-Load Tap Changer
UVLS	Under-Voltage Load Shedding

Appendix A. Overview of the Regional Planning Process

In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. This comprehensive process starts with an assessment of the needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term, and results in the development of a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as-needed basis in Ontario for many years. In the past, planning activities to address regional electricity needs were the responsibility of the former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), which conducted joint regional planning studies with distributors, transmitters, the IESO, and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Ontario Energy Board (OEB) convened a Planning Process Working Group (PPWG) to develop a more structured, transparent, and systematic regional planning process. This group was composed of electricity agencies, utilities, and other stakeholders. In May 2013, the PPWG released its report to the OEB ("PPWG Report"), setting out the new regional planning process. Twenty one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion of regional plans was outlined. The OEB endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, and to the former OPA's licence in October 2013. The licence changes required the OPA to lead two out of four phases of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence became the responsibility of the IESO.

The regional planning process begins with a Needs Assessment stage performed by the transmitter, which determines whether there are needs that should be considered for regional coordination. If further consideration of the needs is required, the IESO conducts a Scoping Assessment to determine what type of planning should be carried out for a region. A Scoping Assessment explores the need for a comprehensive Integrated Regional Resource Plan (IRRP), which considers conservation, generation, transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option, in which case a transmission- and distribution-focused Regional Infrastructure Plan (RIP) can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Assessment and a preliminary terms of reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If a RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a two-week public comment period prior to finalization.

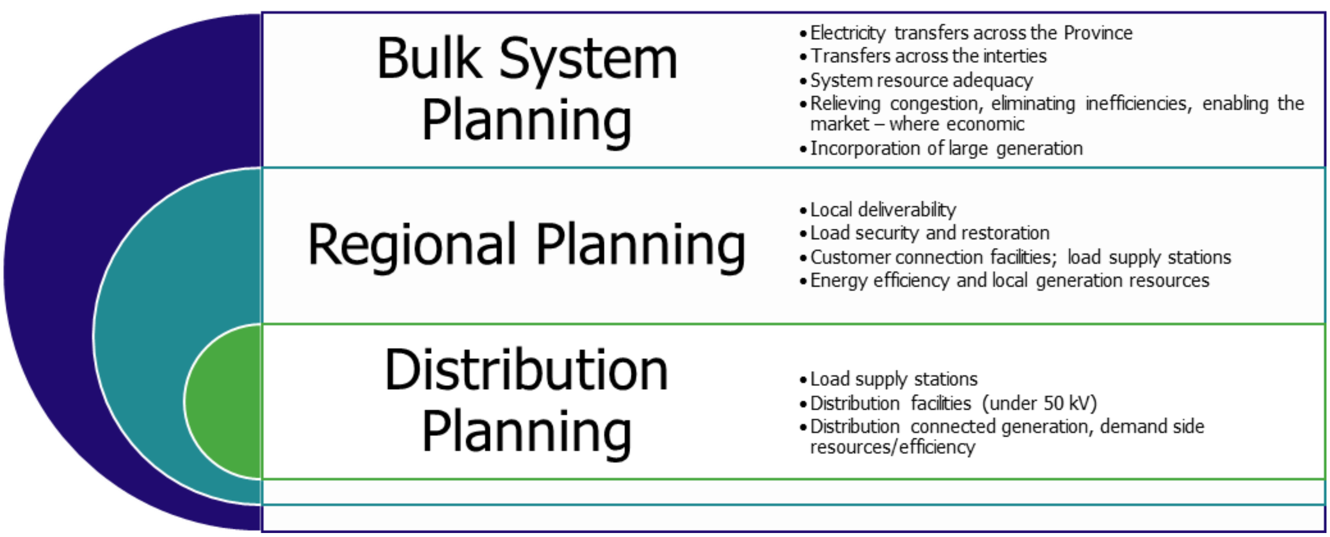
The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs, and RIPs are posted on the IESO's and the relevant transmitter's websites, and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, and for conservation and energy management purposes. They are also a useful source of information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, conservation and demand management (eDSM), and infrastructure requirements. Regional planning is not the only type of electricity planning undertaken in Ontario. As shown in Figure 1, three levels of electricity system planning are carried out in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network, and examines province-wide system issues. In addition to considering major transmission facilities or "wires", bulk system planning assesses the resources needed to adequately supply the province. Distribution planning, which is carried out by local distribution companies (LDCs), considers specific investments in an LDC's territory at distribution-level voltages.

Regional planning can overlap with bulk system planning and with the distribution planning of LDCs. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue, or when a distribution solution addresses the needs of the broader local area or region. As a result, it is important for regional planning to be coordinated with both bulk and distribution system planning, as it is the link between all levels of planning.

Figure 1 | Levels of Electricity System Planning



By recognizing the linkages with bulk and distribution system planning, and coordinating the multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan into perspective. Furthermore, in avoiding piecemeal planning and asset duplication, regional planning optimizes ratepayer interests, allowing them to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

Appendix B. Peak Demand Forecast

This appendix describes the methodologies used to develop the demand forecast for the Windsor-Essex region IRRP studies. Forward-looking estimates of electricity demand were provided by each of the participating LDCs and informed by the forecast base year and starting point provided by the IESO. The sections that follow describe the weather correction methodology, the approaches and methods used by each LDC to forecast demand in their respective service area, the conservation and distributed generation (DG) assumptions, hourly forecasting methodology, and high forecast scenario assumptions.

B.1 Forecast Starting Point Creation

The forecast starting point is the historical demand for a representative reference year (2022 for the Windsor-Essex IRRP) on which LDCs build their gross demand forecasts.

A gross forecast means that existing and new DG, and new eDSM savings are not accounted for in the forecast. Once DG and eDSM are accounted for, they will reduce the gross forecast to produce a net demand forecast: the forecasted demand to be experienced by electricity system infrastructure. LDCs are asked to produce gross forecasts, because the IESO produces the DG and eDSM forecasts. The DG forecast includes existing DG facilities up until the later of when their contracts expire or their expected lifespans as outlined in the 2024 APO Case 2 assumptions, at which point they are removed from the forecast.

To produce the forecast starting point for LDCs, the IESO must first unbundle existing DG impacts from measured historical net demand, to produce historical gross demand, and then weather-normalize the historical gross demand. To produce historical gross demand, the historical hourly output of existing DG facilities[1] is added back onto the measured historical net demand of stations. The weather-normalization methodology is discussed in the next Section. For more information on producing the forecast starting point, please see Section 6.1 of the Load Forecast Guideline for regional planning, published by the OEB through the Regional Planning Process Advisory Group.

B.2 Method for Accounting for Weather Impact on Demand

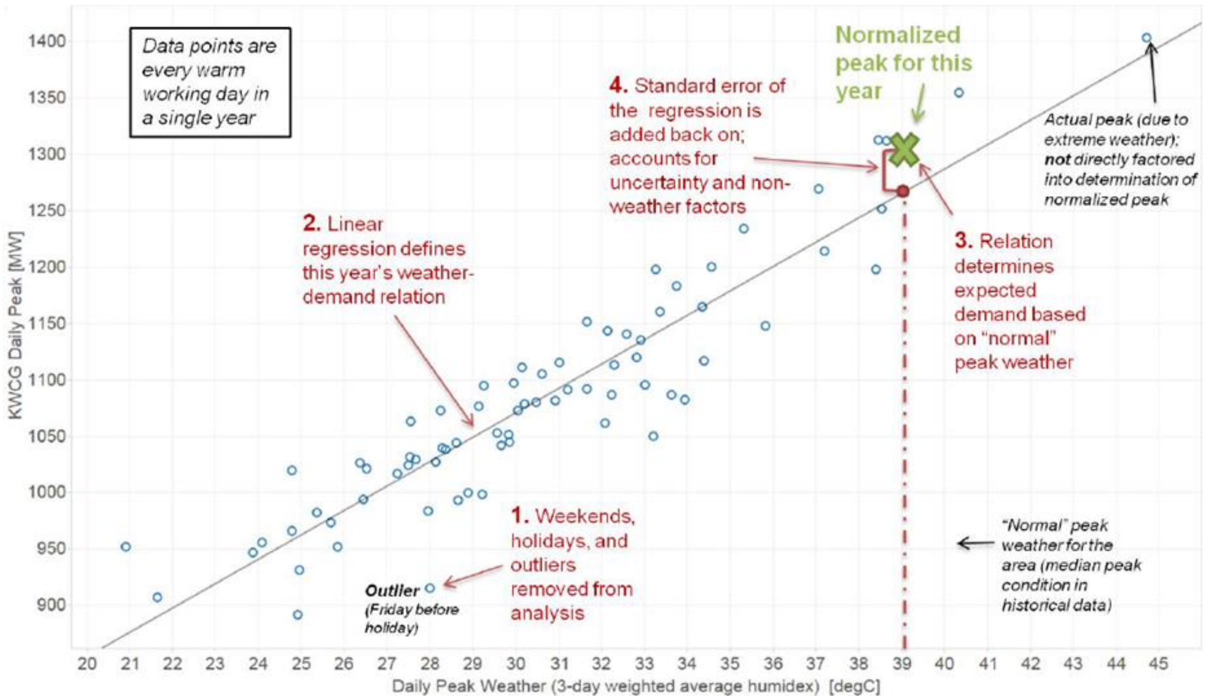
Weather has a large influence on the demand for electricity, so to develop a standardized starting point for the forecast, the historic electricity demand information is weather-normalized. This section details the weather normalization process used to establish the starting point for regional demand forecasts.

First, the historical loads were adjusted to reflect the median peak weather conditions for each transformer station in the area for the 2022 reference year. Median peak refers to the magnitude of

[1] When available, the measured hourly output of DG facilities is used; but if unavailable, the hourly output is estimated using the measured hourly capacity factors of aggregated facilities, and the installed capacity of the specific facility.

peak demand that would be expected if the 50th percentile weather conditions were observed. This means that in any given year there is an estimated 50 per cent chance of exceeding this peak, and a 50 per cent chance of not meeting this peak. The methodological steps are described in Figure 2, and were undertaken for both the summer and winter seasons.

Figure 2 | Method for Determining the Weather-Normalized Peak (Illustrative)



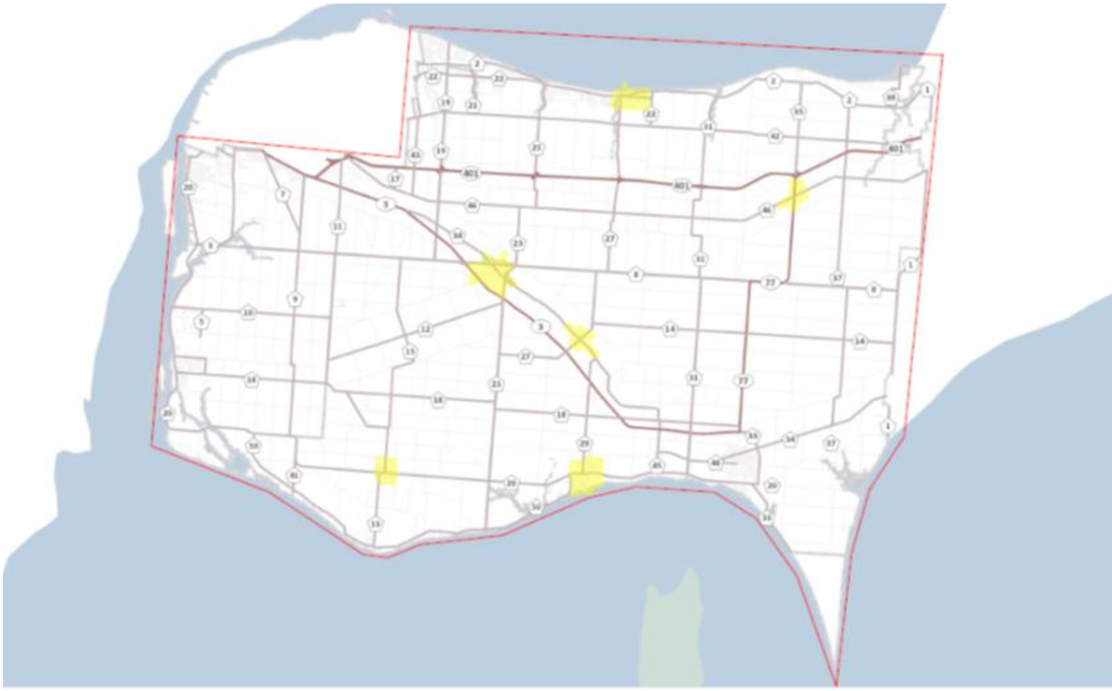
For the IRRP, summer is defined as May to October and winter is defined as November to April. The station-level 2022 median weather summer and winter peaks were provided to each LDC. This data was used as a starting point from which the LDCs could develop 20-year gross median demand forecasts using their preferred methodologies (described in the next sections).

Once the 20-year, median peak demand forecasts were submitted to the IESO, the normal weather forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand, and forecast demand savings from eDSM and contracted DG were accounted for. The studies used to assess the adequacy and reliability of the electric power system are generally required to be based on extreme weather demand – typically the expected demand under the hottest (or coldest) weather conditions that can be reasonably expected to occur. Peaks that occur during extreme weather (i.e., summer heat waves in southern Ontario) are generally when the electricity system infrastructure is most stressed.

B.3 E.L.K. Energy Inc.: Gross Forecast Methodology and Assumptions

Incorporated in 2000, E.L.K. Energy Inc. ("E.L.K.") is the result of a merger of the Hydro-Electric Commission for the Town of Essex, the Corporation of the Town of Lakeshore Hydro-Electric Commission, and the Kingsville Hydro Electric Commission. The Corporation of the Town of Essex ("Town of Essex") is the company's sole shareholder. E.L.K. serves approximately 12,500 customers in the towns of Essex, Lakeshore and Kingsville, with six non-contiguous areas serving the communities of Belle River, Comber, Cottam, Essex, Harrow and Kingsville. As illustrated in the yellow-shaded areas in Figure 3, the total service territory is approximately 22 square-kilometres with approximately 175 km of transmission line.

Figure 3 | Map of the County of Essex Showing E.L.K. Service Territory Highlighted in Yellow



With the majority (almost 90 per cent) of its customers residential, E.L.K. continues to invest in improving both infrastructure and the customer experience – the latter through cost-effective interactive tools.

E.L.K. remains a strong and cost-effective utility, as evidenced in its positive financial ratios, operational effectiveness, and service quality ratios that exceed the targets mandated in the OEB scorecard.

B.3.1 Factors that Affect Electricity Demand

Beyond organic load growth from factors such as population increase, the primary driver of growth in the E.L.K. service territory is electrification across all customer types – residential, commercial, and industrial. Industrial growth in the service territory is lower than that of other LDCs in the region, due in part to the smaller share of industrial customers supplied by E.L.K.

B.3.2 Forecast Methodology and Assumptions

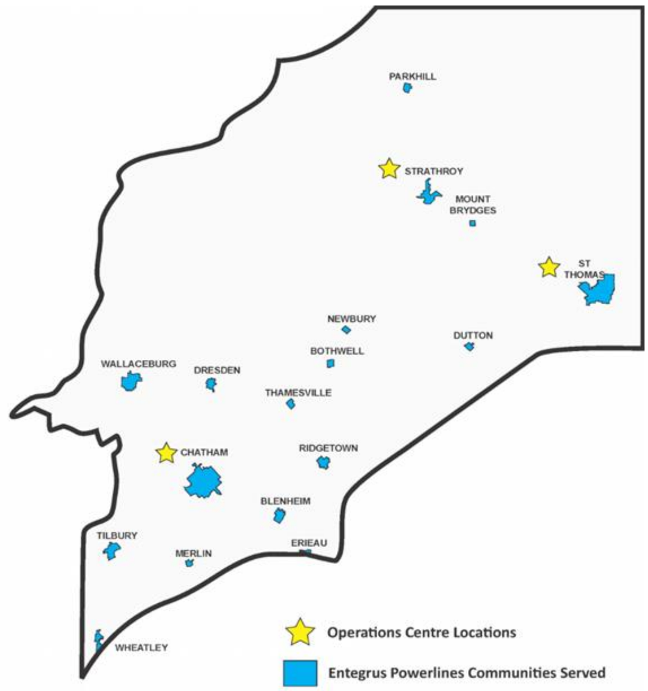
Load forecasts were developed based on historical load growth and demand. There are no known behind-the-meter generation projects planned for E.L.K.'s service areas.

E.L.K. applied flat year-over-year growth rates to their starting point loads, citing the uncertainties surrounding EV penetration and electrification. E.L.K. used the same demand forecast for the reference and high scenarios.

B.4 Entegrus: Gross Forecast Methodology and Assumptions

Owned by the Municipality of Chatham-Kent, the City of St. Thomas, and Corix Utilities, Entegrus Powerlines Inc. ("Entegrus") has customers connected to two transformer stations within the study area: Leamington Transformer Station (TS) and Tilbury West Distribution Station (DS). Entegrus' service area is illustrated in Figure 4.

Figure 4 | Map of the Municipality of Chatham-Kent Showing Entegrus Service Territory



Since March 25, 2018, Entegrus customers in the town of Wheatley have been fed from the M23 feeder out of Leamington TS. Previously, the town was supplied from the M3 feeder out of Kingsville TS. Historic peaks are due to native load, with the majority of demand in the summer from residential load (65 per cent), whereas there is a larger proportion of commercial load in the winter (53 per cent). No capability exists in this area for load transfer to another station.

Entegrus customers in the town of Tilbury are connected to the F1 and F2 feeders out of Tilbury West DS. Historical peaks at this station occurred under normal operating conditions, driven primarily by industrial loads (approximately 60 per cent). As this is the only station serving the town there is no possibility of peaks occurring due to load transfer. There is a solar farm with peak capacity of 5 MW connected to Tilbury West DS, which was transferred from the now decommissioned Tilbury TS.

B.4.1 Factors that Affect Electricity Demand

Entegrus expects residential load growth to be driven by home heating and transportation electrification rather than customer base growth. It was assumed that heat pumps achieve nearly 100 per cent adoption by 2040 within the Entegrus service territory, with air-source heat pumps being installed only as existing gas furnaces fail, rather than through incentivized replacement programs.

Entegrus based their EV adoption rate on vehicle purchase rates provided by Statistics Canada, assuming that the share of EV to internal combustion engine vehicles stays on trend to meet federal targets.

B.4.2 Forecast Methodology and Assumptions

Entegrus assumed a flat year-over-year growth rate due to industrial and commercial load growth. For their EV and electrification forecast assumptions, Entegrus included a time factor in their peak load contribution calculations – an hourly load profile was examined, and applicable hours were selected to be counted towards the peak. For the Planning Forecast, a one per cent year-over-year industrial and commercial growth rate and an EV charging diversity factor of 25 per cent at peak was incorporated. For the high forecast, a three per cent industrial and commercial growth rate along with a 50 per cent EV charging diversity factor at peak was used.

In addition to DG contributions from Entegrus resources the IESO has visibility on, Entegrus provided information on a five megawatt solar facility connected at Tilbury West DS. For this facility, Entegrus provided DG contribution peak info directly to the IESO for use in the DG forecast.

B.5 ENWIN: Gross Forecast Methodology and Assumptions

ENWIN Utilities Ltd. ("ENWIN") is responsible for the distribution of electricity and water, and the servicing and maintenance of electricity and water infrastructure, in the City of Windsor, excluding the annexed area.

Figure 5 | Map of the City of Windsor Showing ENWIN Service Territory

As of the 2021 census, ENWIN served a population of over 229,000 residents in Windsor, with over 90,000 customers at the end of 2022. As shown in Figure 5, ENWIN's service territory in December 2002 is bounded by the area within the City of Windsor and is approximately 120 square-kilometres, with more than 4,700 km of transmission line. Areas that were annexed by the City of Windsor in January 2003 are served by Hydro One Networks Inc.

ENWIN does not have any load transfers in effect with adjacent utilities and is considered a primarily overhead utility with a 60/40 split of overhead and underground primary feeder conductors. The LDC's entirely urban service territory has experienced a slow growth rate and longer recovery from the economic downturn in 2008, with the potential growth limited by the fact that most of its land has already been developed.

B.5.1 Factors that Affect Electricity Demand

The Windsor area has the potential for significant population and economic growth with the possibility of large industrial customers choosing to locate in the area.

Aside from projected residential growth in Windsor, the electrification of buildings and transportation as well as the effects of climate change were incorporated into the ENWIN station forecasts. ENWIN relied on the load forecast survey information provided by the City of Windsor for accurate residential, commercial, and industrial assumptions and their associated forecasted energy use. Detailed items factored into the forecast include heat pumps, EVs, new housing, feeder reconfigurations, commercial heating, and an increase in warm weather days where cooling is required.

B.5.2 Forecast Methodology and Assumptions

As the primary electricity distributor in Windsor, ENWIN derived many of its forecast methodologies and assumptions from the demand forecast survey completed by the City of Windsor for this IRRP cycle. On the residential side, several variables were studied including future energy savings in existing and municipally- and provincially-committed housing, electrification of heating in existing households, EV adoption and mileage estimates, and the electrification of public transit. The impact of overnight charging of electric transportation was also considered. Additional studied variables include the electrification of commercial heating, municipal buildings and the corporate fleet, the expansion of municipal services to support population growth, and an increase in days above 30 degrees Celsius with accompanying cooling load.

The reference and high forecast scenarios provided by ENWIN are differentiated by altering the above variables. In general, the high forecast sees higher household energy usage, a more rapid transition to electric heating in buildings, higher adoption of electric transportation, and warmer weather due to climate change.

During the forecast development process, ENWIN worked with the IESO to provide information on historic load transfers at their supplied stations to construct a more accurate depiction of historical peak demand. ENWIN factored future load transfers and feeder reconfigurations into their load forecast submission.

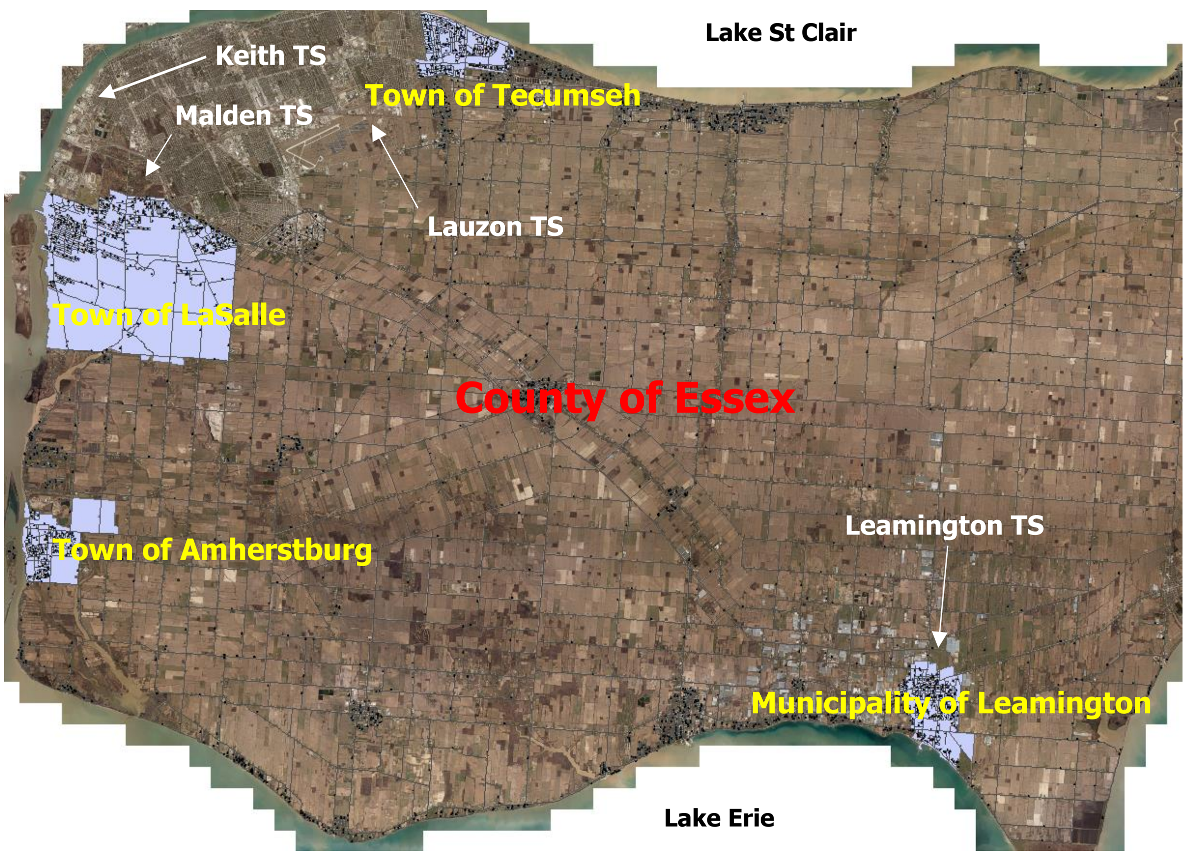
There are several embedded generation projects connected to ENWIN services with contract types varying from net metering to load displacement to the IESO-procured Feed-in-Tariff (FIT) and microFIT. In addition to DG contributions from ENWIN resources the IESO has visibility on, ENWIN provided the IESO with information on contracted generation in their service territory. The IESO incorporated DG resources with a known offer to connect date into the DG forecasts for this IRRP.

B.6 Essex Powerlines Corporation: Gross Forecast Methodology and Assumptions

Essex Powerlines Corporation ("Essex Powerlines") is wholly owned by Essex Power Corporation which, in turn, is wholly owned by the towns of Amherstburg, LaSalle, and Tecumseh and the Municipality of Leamington.

Essex Powerlines services over 31,000 customers, but not all customers in any area except the Town of LaSalle. In the other towns, the rural areas are serviced by Hydro One Networks Inc. The Essex Powerlines customer base is primarily residential and small commercial, with very few large industrial customers. Figure 6 illustrates the over 90 square-kilometre service territory denoted in grey and the locations of upstream 230 kV TS pointed out.

Figure 6 | Map of the County of Essex Showing Essex Powerlines Service Territory



In recent years, several factors have contributed to Essex Powerlines' expansion, including subdivision and apartment/condominium load growth along with related commercial growth. Essex Powerlines has continued to find processes and products to maintain costs, while improving reliability and customer responsiveness.

Essex Powerlines connected to Leamington TS in late 2018 and is seeing both residential and commercial spin-off growth due to greenhouse expansion. LaSalle is expanding rapidly in the residential sector, reaching as far as Amherstburg. Between 2020 to 2030, the Town of LaSalle is anticipated to average approximately 257 new housing units per year and the institutional population is anticipated to increase by approximately 60 people per year. Whereas, Tecumseh has limited growth potential due to only small pockets of undeveloped land.

B.6.1 Factors that Affect Electricity Demand

As the majority of customers connected to Essex Powerlines are residential and commercial, load growth in the service territory is driven by new housing as a result of organic population growth, as well as EV adoption and the electrification of buildings. Demand due to industrial customers constitutes a small percentage of the overall demand Essex Powerlines serves, and Essex Powerlines does not foresee industrial growth in its territory at the same scale as other LDCs in the region.

Each community in the Essex Powerlines service territory was contacted during the forecast development process to review and provide feedback on the Essex Powerlines forecasts. This information was incorporated in the forecasting process of known developments and expected increase in population over the forecast period.

B.6.2 Forecast Methodology and Assumptions

The Essex Powerlines forecast methodology was based on known developments in their service territory and on the square footage of each unit in development. For residential and commercial developments, a rate of two watt per square foot was assumed. For industrial developments, load information was solicited directly from the industrial developer.

Essex Powerlines assumed residential electrification adoption rates of ten per cent for new residential and two per cent for existing residential infrastructure. Future developments – both committed and projected infill – were factored into the forecast, with the latter being estimated using a flat growth factor.

Projected demand due to EV charging was estimated by applying a 20 per cent year-over-year growth factor to existing EV penetration amounts. The existing EV penetration was based on identified units in the Essex Powerlines service territory that would have contributed to peak demand. Overnight demand due to EV charging was not included in the forecast.

Essex Powerlines differentiated their Reference and High Forecast scenarios based on certainty. The Planning Forecast scenario contains known or expected developments. The High Forecast scenario is speculative, incorporating potential but unconfirmed developments from municipalities.

B.7 Hydro One Networks Inc. Distribution: Gross Forecast Methodology and Assumptions

Hydro One Networks Inc. Distribution ("HONI Distribution") provides service to the municipalities and towns across the Windsor-Essex region. HONI Distribution services the majority of customers directly connected to its distribution system except for those served by the three embedded LDCs (Essex Powerlines, E.L.K, and Entegrus).

B.7.1 Factors that Affect Electricity Demand

HONI Distribution supplies electricity to a wide range of customers in multiple communities throughout the Windsor-Essex region. Electricity demand at HONI Distribution-connected stations is forecasted to grow from a mixture of economic and demographic factors, as well as EVs and electrification across all customer types. Growth due to EVs and electrification was estimated in a manner that is consistent with current government policies and local information.

As a major electricity supplier of the greenhouse sector in the Windsor-Essex region, HONI Distribution has been greatly influenced by the recent and projected growth of the sector. To accommodate this demand, multiple IESO-recommended projects are already being considered for implementation. South Middle Road TS Dual-Element Spot Network (DESN) #2 is projected to come in-service in 2025, alongside DESN #1 which began operation in summer 2022. As determined during previous Regional Planning studies, two new 230 kV DESNs in the Leamington area were also projected to be required in the near- to mid-term and are included as a component of Kingsville-Leamington Greenhouse Developments load forecast line item in the load forecasts.

B.7.2 Forecast Methodology and Assumptions

The contribution to growth rates at HONI Distribution stations measures year-over-year per cent growth due to EVs, electrification, and economic and demographic factors. For example, the total load growth in Belle River TS in 2024 is forecasted to be 1.2 per cent, of which 0.2 per cent is due to EVs, 0.001 per cent is due to electrification, and 1 per cent is due to other factors including economic and demographic factors.

HONI Distribution differentiated their Reference and High Forecast scenarios based on firmness of load. In addition to the annual growth rate explained above, greenhouse customer connections that have completed New Customer Connection Information (NCCI) forms were included in the Planning Forecast. The High Forecast incorporates the zoning plans provided by the County of Essex and municipalities in the region, translating this to electricity demand by assigning estimates based on square footage. Industrial and greenhouse loads were also inflated in the High Forecast to encapsulate speculative but not confirmed connections, such as potential customers that have not provided formal NCCI forms.

B.8 Additional Forecast Methodology and Assumptions

The following subsections provide a summary of key factors that impact the community-level growth that was accounted for by the LDCs in their station-level forecasts, as well as factors impacting the greenhouse and industrial sectors, which were accounted for in the forecast as separate line items in the load forecast. These line items have been separated because they include projects either that have been recently approved for development (included in the reference and high forecasts) or that are still speculative (included the high forecast) and as such have not yet been assigned to transformer stations. The inclusion of these forecasts provides a clearer picture of expected and potential load growth in the Windsor-Essex region and allows the Technical Working Group (TWG) to create plans to address this demand, without the need to assume loading at specific areas and stations.

B.8.1 Community Level Growth

City of Windsor

The City of Windsor expects an influx of residents and an associated increase in residential dwellings. The City's November 2020 Development Charges Background Study outlines an expected population growth of 10,400 people between 2020 and 2029. The population increase is met with the development of 6,400 new dwellings in the same timeframe. The City of Windsor has also developed a near-, medium-, and long-term plan for energy conservation in their June 2024 Energy Management Plan. The City has identified actions that will reduce energy use by 12 per cent in the mid-term (2030-2034) and 33 per cent in the long-term (2035-2050).

Municipality of Leamington

The Municipality of Leamington's May 2022 Development Charges Background Study outlines the expected growth in the area. The report outlines an expected population increase of 6,500 people between 2022 and 2032 with a corresponding 1,900 new residential units. The Municipality has outlined approximately 54 hectares of land undergoing residential development in the near-term and approximately 400 hectares considered for future residential development.

Town of Amherstburg

The Town of Amherstburg is focused on developing and upgrading their infrastructure to promote community growth. The Town's 2019 Development Charges Background Study outlines an increase in population of 2,500 people with an accompanying 1,000 new residential units over ten years. A more recent report was published in late 2024. The Town is finalizing their Howard Industrial Secondary Plan which will facilitate the industrial growth of 330 acres of land. In addition, the Town has identified approximately 150 hectares of land that will be used for residential development in the near-term and another approximately 380 hectares considered for future development.

Town of Essex

The Town of Essex released a residential growth forecast in the Town's July 2024 Development Charges Background Study. The population is expected to increase by 2,600 people with an increase of 870 residential units. The Town of Essex expects that new residential subdivisions will have more EV charging. The Town of Essex plans to expand its Settlement Areas for Employment Lands. This expansion would span 45.75 hectares, but a location has yet to be chosen. In addition, the Town of Essex has identified approximately 80 hectares of land for upcoming residential developments and outlined approximately 200 hectares for future development.

Town of Kingsville

The Town of Kingsville, as reported in their November 2022 Development Charges Background Study, expect the population to increase by 3,300 between the years of 2022 to 2032. This is expected to be accompanied by the development of 1,200 new residential units. The Town also anticipates an expansion to its sewage treatment facility resulting in a 30-40 per cent increase in electricity demand. The Town of Kingsville has also identified approximately 70 hectares of land designated for upcoming residential development, and an additional 170 hectares for future development.

Town of Lakeshore

The Town of Lakeshore expects moderate growth between the years of 2020 and 2030 with a population increase of 4,500 as stated in their October 2020 Development Charges Background Study. The Town expects the development of 2,200 new residential units. Lakeshore has identified approximately 1100 hectares of land designated for future residential development in the area.

In the Town's 2019 Energy Conservation and Demand Management Plan, the Town outlined processes, programs, and projects in three sectors that could be leveraged to manage demand. The completion of these objectives is estimated to result in an eight per cent deduction in 2050 energy consumption compared to historic 2018 amounts.

Town of LaSalle

Residential growth in the Town of LaSalle is expanding rapidly. According to the Town's Development Charges Background Study released in October 2020, the net population is expected to increase by over 6,100 people between 2020 and 2030, with a corresponding 2,600 new residential units and 800,000 square feet of new non-residential gross floor area increase. The Town of LaSalle has identified approximately 100 hectares of land that will be developed in the near to mid-term for residential purposes along with another 100 hectares designated for future residential development. The Howard-Bouffard Secondary Plan is a significant plan in the Town of LaSalle that was updated in April 2023. This plan outlines the use of 940 hectares of land and anticipates supporting 29,000 new residents and jobs.

Town of Tecumseh

In the May 2024 Development Charges Background Study, the Town of Tecumseh lists a population increase of 6,000 people between 2024 and 2034. This population growth is accompanied by a 2,600 increase in residential units. The Town also has approximately 210 hectares of land undergoing residential development in the near-term and an additional 210 hectares designated for future residential development. The Town has various plans underway for residential development including the Tecumseh Hamlet Secondary Plan, the Oldcastle Hamlet Development Plan, and the Manning Road Secondary Plan.

Municipality of Chatham-Kent

The Municipality of Chatham-Kent expects rapid growth in the coming years. The Municipality, as reported in their June 2022 Development Charges Background Study, expects the net population to increase by 7,400 people between 2022 and 2032. This population increase is met with 3,500 new residential units.

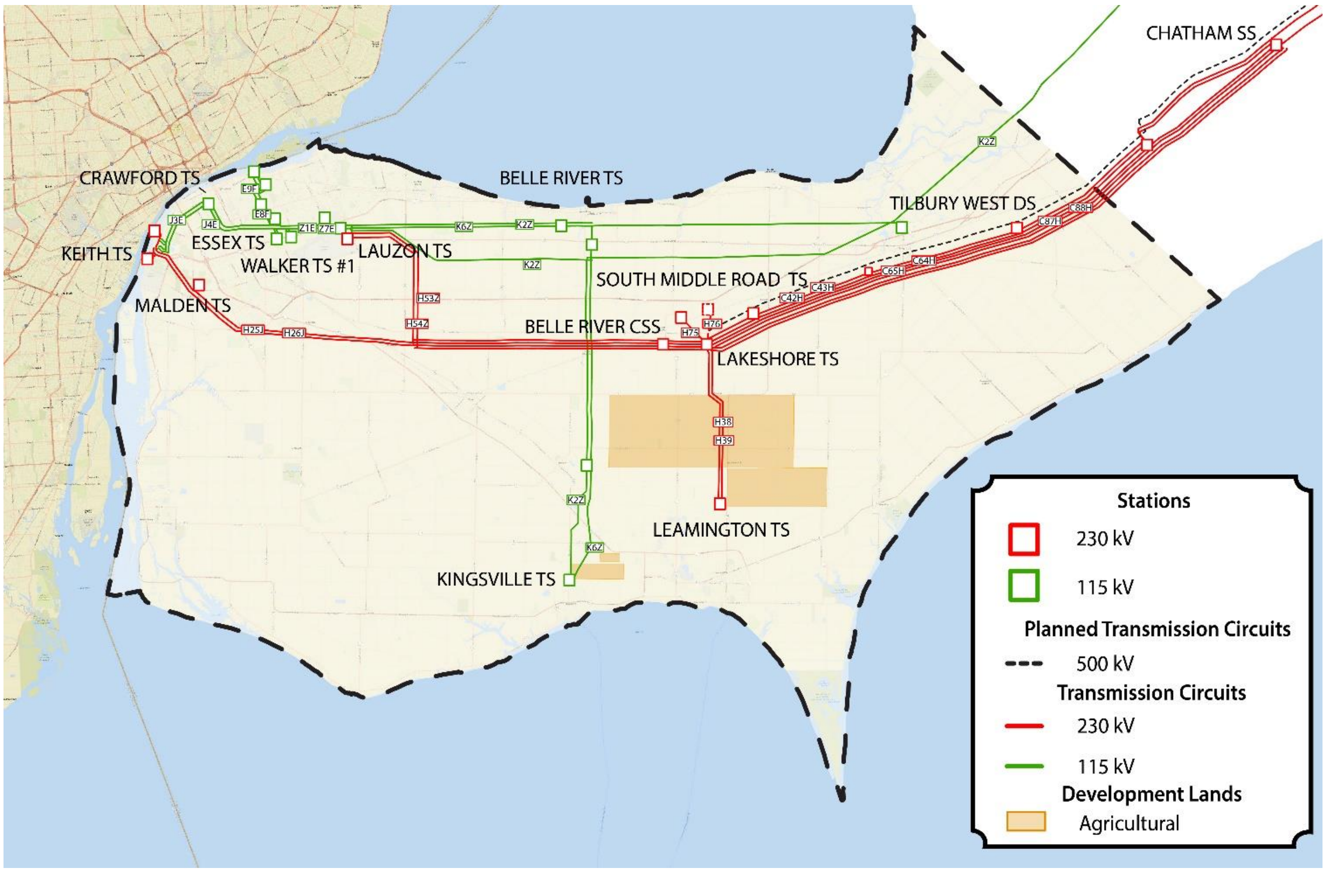
B.8.2 Kingsville-Leamington Greenhouse Developments Forecast

The Kingsville-Leamington Greenhouse Developments load forecast line item incorporates future greenhouse growth in the Windsor-Essex region in locations denoted by HONI Distribution for the

Reference and High Forecasts, based on varying levels of customer commitment. The High Forecast also includes additional growth captured from the 2021 West of London Bulk Transmission Report.

Figure 7 illustrates the geographic area of potential greenhouse developments that were identified to the TWG through the Ontario Greenhouse Vegetable Growers – the not-for-profit organization representing over 170 members who grow greenhouse tomatoes, cucumbers and bell peppers in Ontario, Canada.

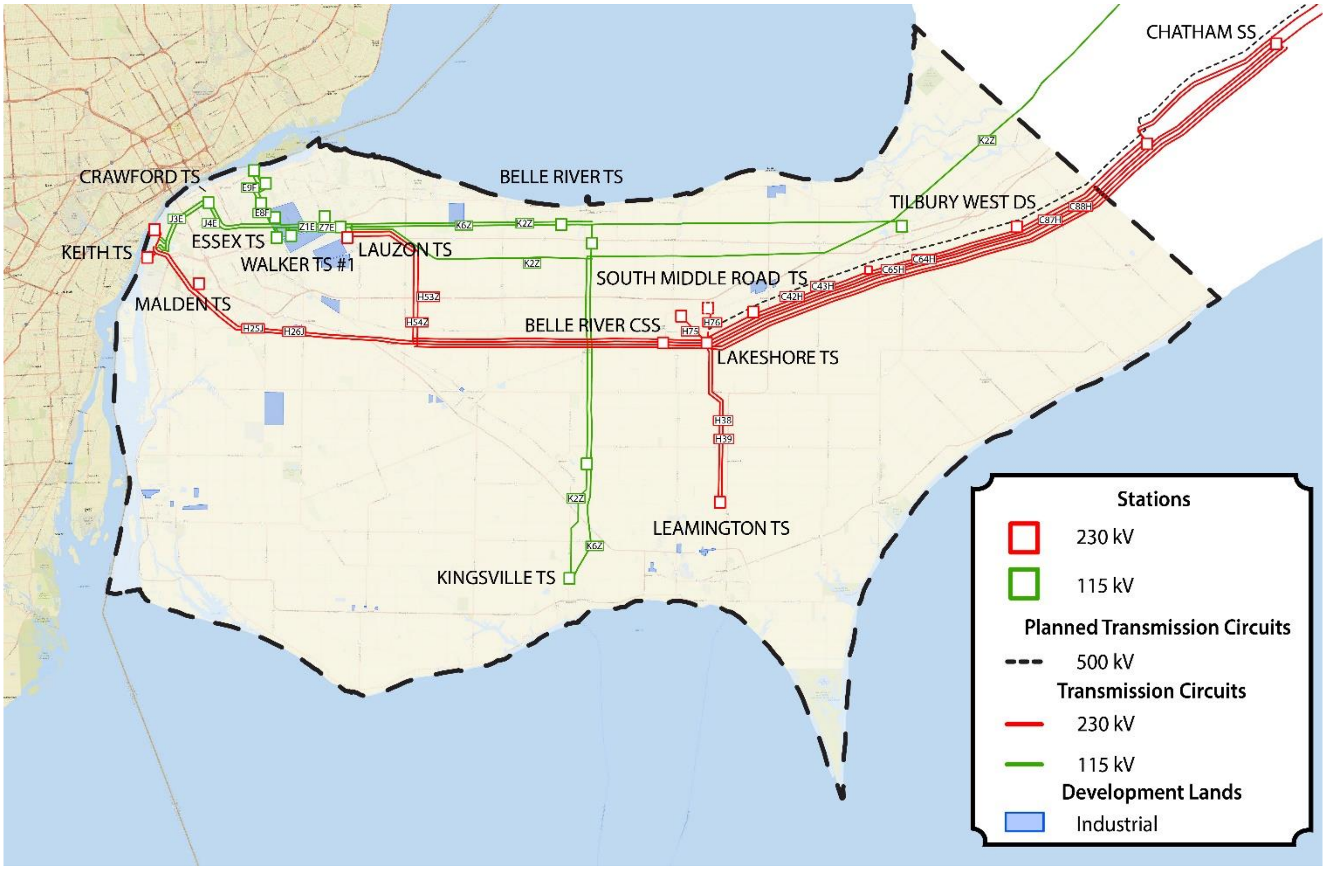
Figure 7 | Illustrative Map of Potential Greenhouse Land Developments Identified in Windsor-Essex



B.8.3 West Essex and Windsor Industrial Developments Forecast

The West Essex and Windsor Industrial Developments load forecast line item was developed using inputs provided by the municipalities as well as Invest WindsorEssex – the not-for-profit organization supported by the City of Windsor and County of Essex responsible for advancing economic development in the region. The municipalities supplied information on potential industrial land developments, as well as Reference and High scenario industrial expansion forecasts in some cases; these were incorporated in the Reference and High load forecasts accordingly. Invest WindsorEssex project information was included in the forecasts based on certainty – firm, committed projects were included in the Planning Forecast, whereas known but unconfirmed projects were additionally included in the High Forecast. As there was no incremental load forecast provided by Invest WindsorEssex, the IESO developed a forecast for this purpose, using the estimated in-service years and ramping loads where in-service dates were not specified. Figure 8 illustrates the geographic area of potential industrial developments that were identified to the TWG by the municipalities and Invest WindsorEssex.

Figure 8 | Illustrative Map of Potential Industrial Land Developments Identified in Windsor-Essex



To avoid double-counting load whilst capturing a reasonable projection of industrial growth in the region, a multi-level approach was taken. In the near-term (from 2024 to 2028), forecast information from Invest WindsorEssex was used, under the assumption that this information more accurately depicts potential near-term industrial developments based on advanced discussions. In the medium- to long-term (from 2029 onwards), the higher of the Invest WindsorEssex or municipal forecast was used.

Additional industrial development information provided by municipalities in the region was incorporated in the station forecasts provided by LDCs.

B.9 Electricity Demand Side Management Assumptions

To reduce the electricity demand, eDSM measures can be used and their impact can be separated into the two main categories: Building Codes and Equipment Standards, and electricity Demand-Side Management (eDSM) programs. The assumptions used for the Windsor-Essex IRRP forecast are consistent with the eDSM assumptions in the IESO's 2024 Annual Planning Outlook including the 2021-2024 Conservation and Demand Management Framework. The savings for each category were estimated according to the forecast residential, commercial, and industrial gross demand. A top-down approach was used to estimate peak demand savings from the provincial level to the West IESO transmission zone and then allocated to the Windsor-Essex region. This section describes the process and methodology used to estimate eDSM savings for the Windsor-Essex region and provides more detail on how the savings for the two categories were developed.

B.9.1. Estimated Savings from Building Codes and Equipment Standards

Ontario building codes and equipment standards set minimum efficiency levels through regulations and are projected to improve and further contribute to demand reduction in the future. To estimate the impact on the region, the associated peak demand savings for codes and standards by sector were estimated for the West zone and compared with the gross peak demand forecast for the zone. From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each station in the region. The analyses were done for summer and winter separately and seasonal peak reduction percentages were estimated.

First, summer peak demand savings were estimated from summer gross demand forecast. Based on the 2023 reference year, new peak demand savings from codes and standards were estimated from 2024 to 2043. The residential annual peak reduction percentages for each year were applied to the forecast residential peak demand at each station to develop an estimate of peak demand impacts from codes and standards for residential sector. By 2043, the residential sector in the region is expected to see about 9.6 per cent summer peak demand savings through codes and standards. The same is done for the commercial sector, which will see about 2.7 per cent summer peak-demand savings through codes and standards by 2043. The sum of the savings associated with the two sectors are the total summer peak demand impact from codes and standards.

The process was repeated for winter peaks. By 2043, the residential sector and commercial sector in the region are expected to see about 6.8 per cent and 1.6 per cent respectively winter peak demand reductions through codes and standards. It is assumed that there are no savings from codes and standards associated with the industrial sector.

B.9.2. Estimated Savings from eDSM Programs

In addition to codes and standards, the delivery of DSM programs reduce electricity demand. The impact of existing and planned eDSM programs were analyzed, which include the 2021-2024 eDSM Framework, the existing federal programs, and the assumed continuation of provincial programs beyond 2024 at savings levels consistent with the current framework adjusted for gross demand growth. A top-down approach was used to estimate the peak demand reduction due to the delivery of these programs from the province to the West zone, and finally to the stations in the region.

Similar to the estimation of peak demand savings from codes and standards, summer and winter peak demand reduction percentages from program savings were developed by sector. The sectoral peak reduction percentages were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in the West zone. They were then applied to the sectoral gross peak forecast of each station in the region. Summer and winter peak demand savings were analyzed separately. By 2043, the residential sector in the region is expected to see about 2.7 per cent summer peak demand savings through programs, while commercial sector and industrial sector will see about 12.7 per cent and 3.5 per cent summer peak reduction respectively. Winter peak reductions by 2043 were estimated as 3.5 per cent, 10.5 per cent, and 3.6 per cent from residential, commercial and industrial programs respectively.

B.9.3. Total eDSM Savings and Impact on the Planning Forecast

As described in the above sections, summer and winter peak demand savings were estimated for each sector and totalled for each station in the region. The analyses were conducted under normal weather conditions. The resulting forecast savings were applied to gross demand to determine net peak demand for further planning analyses.

The eDSM forecast is provided in the Windsor-Essex IRRP Appendix Data Tables as:

Table 1 | IRRP Summer eDSM (Codes and Standards + Energy Efficiency) Forecast

Table 2 | IRRP Winter eDSM (Codes and Standards + Energy Efficiency) Forecast

B.10 Installed Distributed Generation and Contribution Factor Assumptions

DG assumptions are provided in the Windsor-Essex IRRP Appendix Data Tables as:

Table 3 | Distributed Generation Contribution Factor Assumptions

Table 4 | Installed Distributed Generation Summer Output Assumptions

Table 5 | Installed Distributed Generation Winter Output Assumptions

B.11 Final Peak Forecast by Station

After taking the median weather forecast provided by LDCs and applying the eDSM and DG assumptions above, forecasts were adjusted to extreme weather. Load forecasts are determined as either coincident or non-coincident with the region's peak. The final peak demand forecasts, by station, under the reference scenario are provided in the Windsor-Essex IRRP Appendix Data Tables file as:

Table 6 | Summer Coincident Planning Forecast

Table 7 | Summer Non-coincident Planning Forecast

Table 8 | Winter Coincident Planning Forecast

Table 9 | Winter Non-coincident Planning Forecast

The final peak demand forecasts, by station, under the high scenario are provided in the Windsor-Essex IRRP Appendix Data Tables file as:

Table 10 | Summer Coincident High Forecast

Table 11 | Winter Coincident High Forecast

Table 12 | Summer Non-coincident High Forecast

Table 13 | Winter Non-coincident High Forecast

These tables include Customer Transformer Stations (CTS) whose identities have been anonymized.

Appendix C. IRRP NWA Screening Mechanism

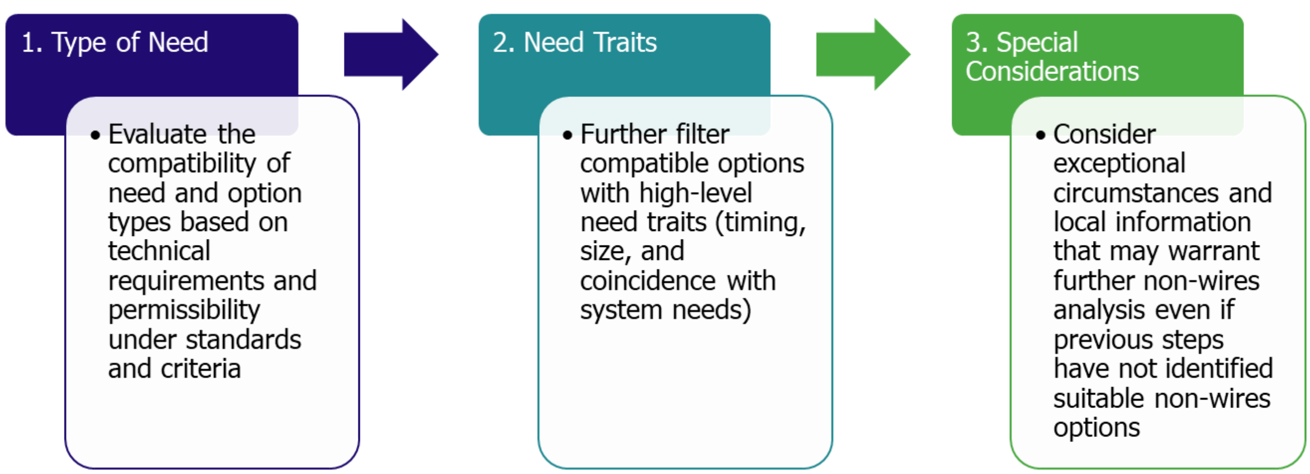
The IESO developed a Guide to Assessing Non-Wires Alternatives, which is the current general approach used during IRRPs. This guide summarizes various recent improvements made to better consider Non-Wires Alternatives (NWAs) when developing an IRRP, including the process flow diagram, screening mechanism, hourly needs characterization, development of options, and economic evaluation methodology. Planning participants and stakeholders can refer to this guide to better understand what key activities to expect during the IRRP.

An NWA screening step is carried out early in the IRRP development process, after local reliability needs have been quantified but before options analysis begins. The screening mechanism provides a framework to identify suitable option types for the unique needs of each IRRP while improving transparency in the TWG's decision-making process, driving more consistency between different IRRPs and focusing options analysis efforts on NWAs that are most likely to be feasible and cost-effective. The screening mechanism results in a shortlist of NWAs requiring further investigation. This list informs which local reliability needs require detailed hourly needs characterization and maps candidate options to each need.

The screening mechanism is intended to be a guide rather than a strict set of criteria. It involves three general steps that are summarized in Figure 9:

1. Suitability by need and option type;
2. Screening by need traits; and
3. Special considerations.

Figure 9 | IRRP NWAs Screening Mechanism



The first step in the screening mechanism is a general suitability filter that considers the type of need and the suitability of options according to its technical characteristics and permissibility under applicable planning criteria, such as the Ontario Resource and Transmission Assessment Criteria (ORTAC), North American Electric Reliability Corporation (NERC) TPL-001-5.1, and Northeast Power Coordinating Council (NPCC) Directory #1.

There are typically five types of needs identified through an IRRP: station capacity needs, supply capacity needs, asset replacement needs, load security needs, and load restoration needs. On the other hand, there are four categories of NWAs differentiated by operating characteristics (e.g. dispatchable vs. non-dispatchable), scalability, and treatment in current planning criteria. These are: transmission-connected generation or energy storage resources, eDSM, DG, and demand response.

Table 1 summarizes the first step for screening NWAs. All NWAs are considered for supply capacity and end-of-life needs. Transmission-connected resources cannot address station capacity needs since the connection point is upstream of the TS. NWAs are not suited to addressing load security needs; however, transmission-connected generation or storage resources and DG can be used to address load restoration needs.

Table 1 | Screening Step 1: Suitability by Need and Option Type

Option \ Need	Supply Capacity	Station Capacity	Asset Replacement	Load Security	Load Restoration
Transmission-connected resources	Yes	No	Yes	No	Yes
EDSM	Yes	Yes	Yes	No	No
DG	Yes	Yes	Yes	No	Yes
Demand response	Yes	Yes	Yes	No	No

After a shortlist of the need/option combinations has been produced, the second step of the screening mechanism further reduces this shortlist by considering the need's high-level characteristics, such as the size of the need and the coincidence with system peak. Table 2 summarizes how this screening is applied to each option.

Table 2 | Screening Step 2: Narrow Down Options Based on High-Level Need Traits

Option	Size of the need	Coincidence of the need with system peak
Transmission-connected resources	Not applicable – always screened in	Always screened in – generation can likely provide system value during provincial peaks even if local need is not coincident
EDSM	Screened in if need is less than two per cent of the load forecast in each year	Screened in only if coincident with system peaks

Option	Size of the need	Coincidence of the need with system peak
DG	Screened in if need is less than the available DG connection space	Always screened in – generation can likely provide system value during provincial peaks even if local need is not coincident
Demand response	Screened in if need is proportional to the historically offered amount of demand response in the capacity auction	Screened in only if coincident with system peaks

The third and final step of the screening mechanism does not include a set of criteria – rather, it is to recognize the flexibility in IRRPs for exceptional circumstances and the uniqueness of each region. In some cases, special considerations could warrant further NWA analysis regardless of the screening steps and outcomes described above. To account for the uniqueness of each region, the TWG considers factors such as:

- Government policy or stakeholder support;
- Local preferences around solutions that the community will host;
- Unique load characteristics;
- Opportunities to explore a novel technology or operating model;
- Demand forecast uncertainty;
- Opportunities for integrated solutions; and
- Availability of inexpensive and simple wires options that maximize the use of existing infrastructure.

The needs for which DG was screened in as a NWA, are subject to technical limitations on connection space as outlined in Table 3.

Table 3 | Estimated DG Connection Space[2]

Station	Estimated DG Connection Space (MW)
Belle River TS	30
Lauzon DESN2	60
Leamington DESN1	0
Leamington DESN2	0
South Middle Road DESN1	0
South Middle Road DESN2[3]	N/A
Tilbury West DS	20

[2] Actual connection feasibility would be subject to further studies. Estimated based on information from the LDCs and the DG connection capacity found on the Hydro One website. For up-to-date information, please contact local distribution companies.

[3] South Middle Road DESN2 expected to come into service in 2025.

Appendix D. Hourly Demand Forecast

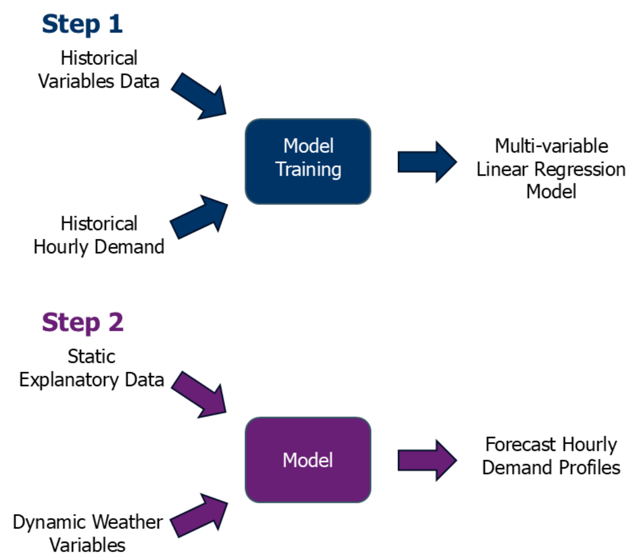
D.1 General Methodology

An hourly demand forecast consists of a series of year-long hourly profiles ("8760 profile", based on the number of hours in a year), which have been scaled to the appropriate annual peak demand. These profiles are developed to help determine which NWAs may be best suited to meet regional needs.

For the Windsor-Essex IRRP, hourly load forecasting was conducted on a station-level for stations with capacity needs or with upstream supply capacity needs, that were screened in using the IRRP NWA screening mechanism in Figure 9. The screened in needs were the West Essex and Windsor supply capacity need, the Tilbury West DS station capacity need, and the Kingsville-Leamington greenhouse developments station capacity need.

Forecasting was completed using a multi-variable linear regression with approximately five years' worth of historical hourly load data. The two-step approach to hourly forecasting in IRRPs is summarized in Figure 10, and described further below.

Figure 10 | Summary of the Hourly Forecasting Methodology for IRRPs



First, a density-based clustering algorithm was used to filter the historical data for outliers (including fluctuations possibly caused by load transfers, outages, or infrastructure changes). Subsequently, the historical hourly data was combined with select predictor variables to perform a multi-variable linear regression and model the station's hourly load profile. The following predictor variables were used:

- Weather factors (temperature, cloud cover, humidity, and wind chill);
- Global horizontal irradiance;
- Econometric factors (population, employment);

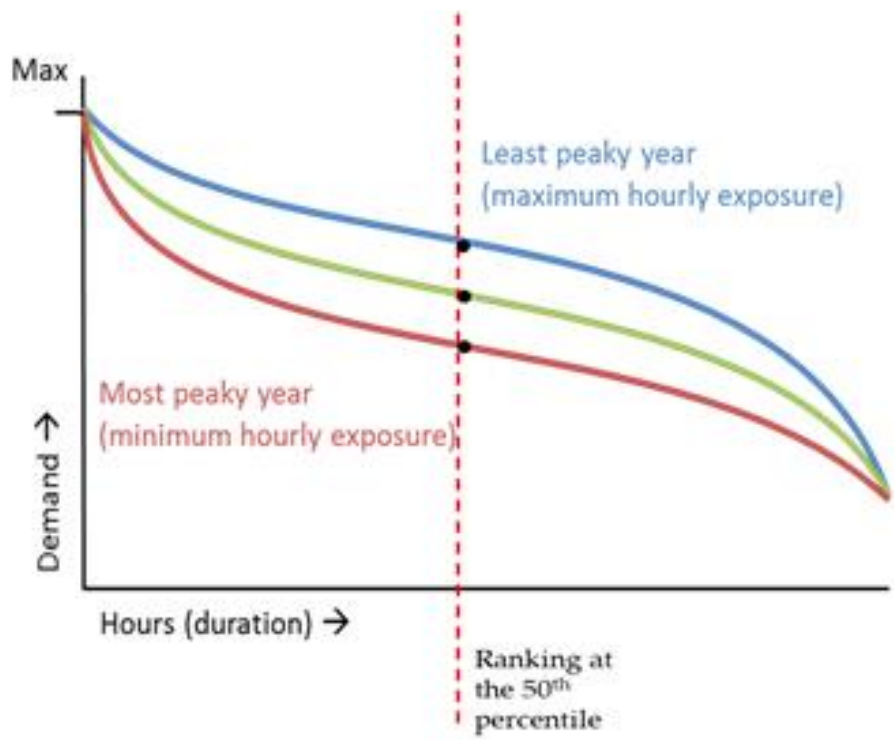
- COVID-19 impacts; and,
- Calendar factors (holidays and days of the week).

Model diagnostics (i.e., training mean absolute error and testing mean absolute error) were used to gauge the effectiveness of the selected predictor variables and to avoid an over-fitted model. Once the model was developed, it was applied with projections of the predictor variables. While future values for calendar, demographic, and economic variables were incorporated in a relatively straightforward manner, the unreliability of long-term weather forecasts necessitated a different approach for predicting the impact of future weather.

To assess the impact that different weather sequences can have against the other non-weather variables (in particular, the calendar), a set of several possible future hourly weather forecasts is produced. To start, the historical hourly weather data from the past 31 years were recorded, producing 31 annual hourly profiles (each profile consists of 8760 hours, covering one year). Then, each of these 31 profiles was shifted both ahead and behind by up to seven days. This process generates an additional 14 new profiles from each of the previous 31 profiles. This approach ultimately leads to 465 (15 iterations of the 31 historical years) possible hourly weather forecasts for each future year. For example, the set of possible weather on June 2nd 2023 consists of the historical weather that occurred from every May 26th to June 9th from 1992 to 2022.

Subsequently, the set of 465 weather forecasts (together with the forecast of non-weather variables) were used to produce 465 load forecasts, which were ranked in ascending order based on their annual energy values. Load duration curves which illustrate this ranking can be seen in Figure 11. The forecast at the 50th percentile is the "Median Peak" (which is the middle, green curve below), and was scaled so that its maximum matched the peak demand forecast.

Figure 11 | Illustrative Example: Ranking Hourly Load Profiles by Energy



Hourly forecasts are a direct input for further NWAs assessments when combined with the relevant local transmission limits. The shape of the forecasted load that exceeds transmission limits is referred to as the need profile, or energy-not-served. Need profiles help identify key characteristics – the magnitude, frequency, and duration of possible need events, and how they could be dispersed over the days, months, and years in the 20-year planning horizon.

Sections D.2 through D.4 contain examples of the forecast hourly profiles for the West Essex and Windsor supply capacity need, the Tilbury West DS station capacity need, and the Kingsville-Leamington greenhouse developments station capacity need.

D.2 West Essex and Windsor Supply Capacity Need

The 8760 profiles are analyzed using heat maps to calculate the proportion of hours exceeding various thresholds and visually represent the data. Figure 12 shows the heat map for the monthly West Essex and Windsor supply capacity need in the final year of the forecast, 2043. Each cell in the heat map indicates the expected proportion of the magnitude of the need, for each month of the year. The heat map indicates that the need peaks in July and the number of days of need is greatest in August. For instance, one per cent of hours in July are projected to have a supply capacity need greater than 200 MW and 50 per cent of hours in August are projected to have a supply capacity need.

Figure 12 | Heat Map Showing Possible Frequency of West Essex and Windsor Supply Capacity Monthly Need in 2043, by MW

MW Range of Need	Percentage of Days Exceeding Need Threshold at Specified Month											
300+	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
267	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
233	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
200	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
167	0%	0%	0%	0%	0%	0%	1%	2%	0%	0%	0%	0%
133	0%	0%	0%	0%	0%	1%	2%	4%	0%	0%	0%	0%
100	0%	1%	0%	0%	0%	4%	4%	10%	1%	0%	0%	0%
67	3%	3%	2%	0%	1%	10%	12%	20%	5%	0%	1%	1%
33	7%	9%	6%	1%	3%	17%	23%	35%	10%	0%	3%	4%
0	19%	20%	11%	5%	5%	26%	36%	50%	19%	3%	10%	13%
	1	2	3	4	5	6	7	8	9	10	11	12
	MONTH											

Figure 13 depicts the heat map for the West Essex and Windsor supply capacity need during summer months, according to the hour of the day. The summer profile shows that the need is present between 4 AM and midnight and is highest between 3 PM and 8 PM. For example, 56 per cent of summer days are expected to have a supply capacity need between 7 PM and 8 PM and one per cent of summer days are expected to have a supply capacity need greater than 200 MW over the same hour.

Figure 13 | Heat Map Showing Possible Frequency of West Essex and Windsor Supply Capacity Summer Need in 2043, by MW and Hours of the Day

MW Range of Need	Percentage of Summer Days Exceeding Need Threshold at Specified Hour																							
300+	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
267	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
233	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
200	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	1%	0%	0%	0%	0%
167	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	3%	2%	1%	1%	3%	1%	0%	0%	0%
133	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	3%	4%	4%	1%	8%	1%	0%	0%	0%
100	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	1%	1%	3%	3%	5%	13%	10%	9%	4%	23%	4%	1%	0%	0%
67	0%	0%	0%	0%	0%	1%	7%	0%	1%	1%	2%	3%	5%	8%	17%	26%	26%	23%	13%	37%	17%	3%	0%	0%
33	0%	0%	0%	0%	1%	8%	28%	2%	2%	3%	5%	10%	13%	19%	32%	39%	37%	36%	28%	46%	35%	10%	2%	0%
0	0%	0%	0%	0%	4%	34%	52%	5%	10%	10%	13%	23%	28%	34%	40%	44%	43%	43%	39%	56%	44%	29%	4%	1%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	HOUR																							

Conversely, Figure 14 depicts the winter profile, which shows that the need is less persistent during winter months and is not present between 9 AM and 2 PM. The highest winter peaks occur between 6 AM and 7 AM and 7 PM and 8 PM. Comparing these two need profiles, the summer season is the dominant need for the West Essex and Windsor supply capacity; however, the winter need profile is still important when considering the total energy requirements and seasonal demand requirements for meeting the need.

Figure 14 | Heat Map Showing Possible Frequency of West Essex and Windsor Supply Capacity Winter Need in 2043, by MW and Hour of the Day

MW Range of Need	Percentage of Winter Days Exceeding Need Threshold at Specified Hour																							
300+	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
267	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
233	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
200	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
167	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
133	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
100	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%
67	0%	0%	0%	0%	0%	6%	20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	6%	1%	0%	0%	0%
33	0%	0%	0%	0%	2%	24%	51%	1%	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	1%	28%	6%	1%	0%	0%
0	0%	0%	0%	3%	18%	57%	72%	9%	4%	0%	0%	0%	0%	0%	2%	10%	14%	13%	6%	60%	30%	7%	1%	0%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	HOUR																							

The complete 8760 profile for the final forecast year, 2043, is provided in the Windsor-Essex IRRP Appendix Data Tables file along with these heat maps as:

Table 14 | 8760 Profile of West Essex and Windsor Supply Capacity Need (2043)

Table 15 | Heat Map of West Essex and Windsor Monthly Supply Capacity Need (2043)

Table 16 | Heat Map of West Essex and Windsor Hourly Summer Need (2043)

Table 17 | Heat Map of West Essex and Windsor Hourly Winter Need (2043)

D.3 Tilbury West DS Station Capacity Need

Figure 15 shows the heat map for the monthly Tilbury West DS station capacity need in the final year of the forecast, 2043. Each cell in the heat map indicates the expected proportion of the magnitude of the need, for each month of the year. The need is relatively consistent between winter and summer months, with the winter need being slightly higher than summer, as indicated by one per cent of hours in February projected to have a station capacity need greater than 11 MW. The summer need is more persistent than winter.

Figure 15 | Heat Map Showing Possible Frequency of Tilbury West DS Station Capacity Monthly Need in 2043, by MW

MW Range of Need	Percentage of Days Exceeding Need Threshold at Specified Month										
20+	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
9	2%	2%	2%	0%	0%	0%	3%	4%	0%	0%	1%	2%
7	9%	7%	5%	1%	0%	3%	11%	16%	5%	1%	2%	8%
4	21%	22%	21%	4%	1%	9%	25%	29%	18%	6%	6%	19%
2	39%	53%	46%	14%	10%	25%	50%	55%	43%	19%	17%	31%
0	58%	74%	65%	29%	27%	58%	77%	84%	74%	44%	36%	46%
	1	2	3	4	5	6	7	8	9	10	11	12
	MONTH											

The summer heat map by hour of the day is depicted in Figure 16. Each cell in the heat map indicates the expected proportion of the magnitude of the need for Tilbury West DS, according to the hour of the day. The summer profile shows that the need persists 24 hours per day. Over 70 per cent of summer days are expected to have a station capacity need between 3 PM and 10 PM. The need is greatest between 6 PM and 7 PM when one per cent of summer days are expected to have a station capacity need greater than 11 MW.

Figure 16 | Heat Map Showing Possible Frequency of Tilbury West DS Station Capacity Summer Need in 2043, by MW and Hours of the Day

Percentage of Summer Days Exceeding Need Threshold at Specified Hour

MW Range of Need	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
20+	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	3%	7%	10%	4%	1%	0%	0%	0%
7	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	1%	1%	2%	10%	16%	21%	26%	29%	20%	11%	2%	0%	0%
4	0%	0%	1%	2%	2%	5%	8%	5%	4%	2%	2%	5%	10%	11%	20%	36%	40%	49%	53%	44%	31%	17%	0%	1%
2	10%	7%	7%	19%	25%	38%	40%	23%	16%	10%	13%	14%	22%	23%	45%	60%	65%	73%	77%	71%	57%	43%	23%	13%
0	42%	40%	47%	52%	59%	65%	65%	54%	45%	30%	28%	33%	45%	53%	64%	83%	86%	89%	92%	90%	85%	74%	58%	46%

HOUR

Similarly, the winter profile in Figure 17 shows that the need is more persistent during winter months and is present during all hours of the day. The highest winter peaks occur between 4 PM and 9 PM when one per cent of winter days are expected to exceed 11 MW. The station is forecast to be winter peaking by the end of the forecast period, but both seasons form a critical part of the Tilbury West DS need.

Figure 17 | Heat Map Showing Possible Frequency of Tilbury West DS Station Capacity Winter Need in 2043, by MW and Hour of the Day

Percentage of Winter Days Exceeding Need Threshold at Specified Hour

MW Range of Need	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
20+	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%
9	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	1%	2%	4%	7%	6%	6%	4%	1%	0%	0%
7	1%	1%	1%	1%	1%	4%	6%	3%	1%	1%	1%	1%	1%	2%	3%	12%	14%	17%	18%	14%	13%	8%	0%	1%
4	6%	6%	4%	6%	10%	18%	24%	17%	11%	4%	3%	3%	4%	7%	15%	30%	34%	36%	36%	34%	27%	23%	1%	6%
2	20%	21%	21%	28%	31%	39%	42%	36%	25%	16%	12%	10%	17%	18%	31%	51%	53%	60%	60%	57%	49%	41%	20%	22%
0	40%	40%	41%	44%	50%	59%	62%	56%	44%	33%	27%	26%	29%	37%	54%	69%	68%	70%	69%	66%	65%	61%	51%	41%

HOUR

The complete 8760 profile for the final forecast year, 2043, is provided in the Windsor-Essex IRRP Appendix Data Tables file along with these heat maps as:

Table 18: 8760 Profile of Tilbury West DS Station Capacity Need (2043)

Table 19: Heat Map of Tilbury West DS Monthly Station Capacity Need (2043)

Table 20: Heat Map of Tilbury West DS Summer Need (2043)

Table 21: Heat Map of Tilbury West DS Winter Need (2043)

D.4 Kingsville-Leamington Greenhouse Developments Capacity Need

Figure 18 shows the heat map for the monthly Kingsville-Leamington greenhouse developments station capacity need in the final year of the forecast, 2043. Each cell in the heat map indicates the expected proportion of the magnitude of the need, for each month of the year. The need is persistent year-round but varies drastically between summer and winter months The summer need is less than 100 MW between May and August, whereas the winter need exceeds 350 MW between December and March.

Figure 18 | Heat Map Showing Possible Frequency of Kingsville-Leamington Greenhouse Station Capacity Monthly Need in 2043, by MW

MW Range of Need	Percentage of Days Exceeding Need Threshold at Specified Month											
450+	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
400	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
350	11%	25%	7%	0%	0%	0%	0%	0%	0%	0%	0%	11%
300	39%	44%	19%	0%	0%	0%	0%	0%	0%	14%	18%	30%
250	48%	51%	32%	0%	0%	0%	0%	0%	0%	30%	31%	42%
200	56%	60%	42%	0%	0%	0%	0%	0%	0%	50%	49%	53%
150	74%	75%	57%	1%	0%	0%	0%	0%	5%	66%	66%	71%
100	82%	80%	80%	12%	0%	0%	0%	0%	25%	78%	79%	81%
50	100%	100%	100%	69%	57%	47%	46%	49%	73%	100%	100%	100%
0	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	1	2	3	4	5	6	7	8	9	10	11	12
	MONTH											

Figure 19 shows the heat map for the Kingsville-Leamington station capacity need in summer, by hour of the day. The summer profile shows that the need persists 24 hours per day and is present for 100 per cent of days. The summer need is greatest between 3 AM and 10 AM.

Figure 19 | Heat Map Showing Possible Frequency of Kingsville-Leamington Greenhouse Development Station Capacity Summer Need in 2043, by MW and Hours of the Day

MW Range of Need	Percentage of Summer Days Exceeding Need Threshold at Specified Hour																							
450	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
400	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
350	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
250	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
200	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
150	0%	0%	0%	1%	3%	4%	7%	7%	2%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
100	0%	7%	7%	8%	12%	13%	14%	14%	12%	5%	4%	4%	4%	5%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%
50	14%	16%	16%	38%	63%	77%	89%	100%	100%	100%	100%	100%	100%	100%	100%	78%	56%	24%	0%	0%	0%	0%	14%	14%
0	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	HOUR																							

The winter profile shown in Figure 20 also indicates a persistent need but with a magnitude of load that is significantly greater than the summer need. The highest winter peaks occur between 3 AM and 2 PM when load is expected to exceed 350 MW, peaking at 390 MW. Greenhouse growing practices are continuously evolving and the 24-hour profile is expected to change in the future. The TWG will revisit these profiles in the next round of Regional Planning.

Figure 20 | Heat Map Showing Possible Frequency of Kingsville-Leamington Greenhouse Development Station Capacity Winter Need in 2043, by MW and Hour of the Day

MW Range of Need	Percentage of Winter Days Exceeding Need Threshold at Specified Hour																							
450	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
400	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
350	0%	0%	0%	3%	13%	22%	32%	35%	29%	12%	8%	8%	11%	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300	0%	26%	36%	38%	41%	60%	72%	78%	59%	32%	29%	29%	31%	15%	7%	2%	0%	0%	0%	0%	0%	0%	0%	0%
250	16%	42%	45%	60%	76%	85%	86%	86%	78%	56%	38%	37%	39%	35%	13%	3%	0%	0%	0%	0%	0%	0%	0%	0%
200	36%	77%	85%	86%	86%	86%	86%	86%	85%	79%	59%	43%	44%	48%	44%	14%	1%	0%	0%	0%	0%	0%	0%	19%
150	78%	85%	86%	86%	86%	87%	87%	86%	86%	83%	83%	79%	79%	79%	79%	71%	13%	1%	0%	0%	0%	0%	33%	40%
100	86%	86%	87%	89%	91%	93%	95%	93%	89%	88%	87%	86%	86%	86%	86%	86%	55%	29%	0%	0%	0%	25%	79%	86%
50	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	98%	95%	91%	86%	86%	86%	86%	86%	88%
0	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	HOUR																							

The complete 8760 profile for the final forecast year, 2043, is provided in the Windsor-Essex IRRP Appendix Data Tables file along with these heat maps as:

Table 22: 8760 Profile of Kingsville-Leamington Greenhouse Station Capacity Need (2043)

Table 23: Heat Map of Kingsville-Leamington Greenhouse Monthly Station Capacity Need (2043)

Table 24: Heat Map of Kingsville-Leamington Greenhouse Summer Need (2043)

Table 25: Heat Map of Kingsville-Leamington Greenhouse Winter Need (2043)

Appendix E. Electricity Demand Side Management

Electricity Demand-Side Management (eDSM) is a low-cost resource that offers significant benefits to individuals, businesses, and the electricity system as a whole. Targeting eDSM in areas of the province with regional and local needs can help offset investments in new resources or transmission, defer this spending to a later date, and/or can complement these investments as part of an integrated solution for the area.

To understand the scale of opportunity and associated costs for targeting eDSM in a local area, data and assumptions can be leveraged from provincial eDSM potential forecasts. In 2019, the IESO and the OEB completed the first integrated electricity and natural gas achievable potential study in Ontario ("2019 APS"). The main objective of the APS was to identify and quantify energy savings potential (for both electricity and natural gas), greenhouse gas emission reductions, and associated costs from demand-side resources for the period from 2019-2038 under different scenarios. This achievable potential modeling is used to inform:

- Future energy efficiency policy and/or frameworks;
- Program design and implementation; and
- Assessments of eDSM non-wires potential in regional planning.

The 2019 APS determined that both electricity and natural gas have significant cost-effective energy efficiency potential in the near and longer terms. In particular, the maximum achievable potential scenario is one scenario in the APS that estimates the available potential from all eDSM measures that are cost effective from the provincial system perspective – i.e., they produce benefits from avoided energy and system capacity costs that are greater than the incremental costs of the measures.

The results of the 2019 APS were updated with the 2022 Achievable Potential Study ("2022 APS"). The 2022 APS shows that under the maximum achievable potential scenario, eDSM measures have the potential to reduce summer electricity peak demand by up to 3,500 MW in the province over the 20-year forecast period and can produce up to 28 TWh of energy savings over the same period.

After scaling this level of forecasted maximum achievable savings potential to the local area, the forecasted savings that are expected to come from existing provincial and federal eDSM programs, the forecasted savings that are expected to come from future anticipated eDSM programs, as well as savings from codes and standards, were netted out and the remaining achievable savings potential were identified. The remaining potential provides an estimate of the amount of incremental eDSM savings potential that could help address emerging local needs in the Windsor-Essex region.

E.1 Regional Characteristics of eDSM Measures

The potential for eDSM initiatives to reduce the peak-demand requirements in the Windsor-Essex region is mostly encapsulated within industrial and agricultural eDSM programs. In 2023, there were 2.7 MW of verified eDSM savings in the Windsor-Essex region. The most significant demand savings come from the Retrofit Prescriptive Program (1.8 MW) and the Targeted Greenhouse Program (0.6 MW).

Horticultural lighting represents the largest untapped potential for eDSM savings in the Windsor-Essex region. The region is home to a large agricultural sector including a concentration of greenhouses which use horticultural lighting to grow produce year-round. Whereas the Retrofit Prescriptive Program offers province-wide incentives to industrial, commercial, institutional, and multi-unit residential customers, the Targeted Greenhouse Program specifically targets the greenhouse sector in the south-west region of Ontario as directed by the West of London Bulk Planning Report.

Uptake of Light Emitting Diodes (LEDs) has increased in recent years as demonstrated by past Targeted Greenhouse Program results. LED grow lights cost approximately four times as much as traditional high-pressure sodium (HPS) and incentives can help fill the gap while providing energy efficiency savings to the region and province. In addition to the incentives, LED lighting is gaining popularity in vertical farming and for its tunable light spectrum. However, HPS is still the most popular lightning technology used in Ontario greenhouses. While HPS lights are less efficient than their LED counterparts, they provide a broader light spectrum, the extra heat generated is utilized in the greenhouse, and they have a longer history of use in the sector.

The Targeted Greenhouse Program is not limited to LED lighting conversion, it also includes advanced lighting controls. Going forward, there is opportunity to promote integrated solutions that combine lighting, HVAC, and behind-the-meter generation.

Other province-wide eDSM programs such as the smart thermostat "Peak Perks" program, First Nations Community Building Retrofit Program, the Industrial Energy Efficiency Program, and the Small Business Program are expected to remain in place and contribute to energy savings under the 2025-2036 framework. Across the Windsor-Essex region, eDSM measures remain an important tool for supporting both short-term and long-term growth.

E.2 Incremental Energy Savings Forecasts for the Windsor-Essex Region

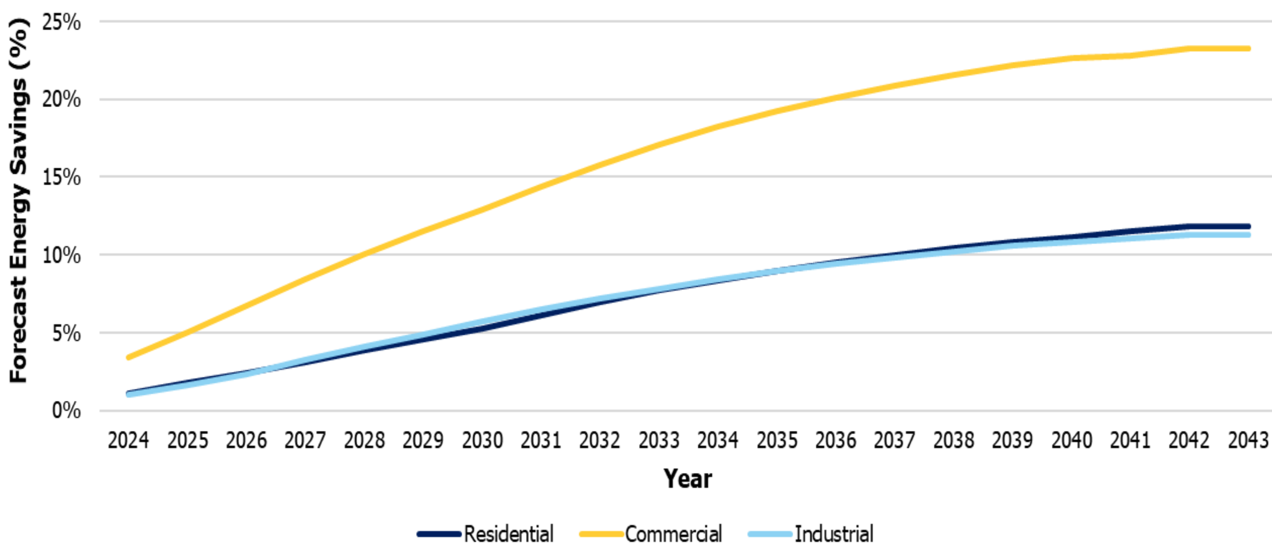
Based on the 2022 APS maximum achievable savings potential forecast, it is estimated that eDSM has the potential to reduce demand in the Windsor-Essex region in the West zone. In the near-term, a portion of these achievable savings opportunities are captured by the 2021-2024 Conservation and Demand Management Framework, its evolution under the 2025-2036 Electricity Energy Efficiency Framework, and Federal energy efficiency programs. Over time, new opportunities emerge with savings potential available across all sectors in this zone. The 2021-2024 Conservation and Demand Management Framework was based on energy efficiency programs centrally delivered by the IESO under the "Save on Energy" brand to commercial, institutional, industrial, on-reserve First Nations communities, and residential customers. In January 2025, the provincial government announced a new eDSM framework for 2025-2036 with the following priority areas:

1. A more enduring funding framework that potentially looks beyond a four-year timeframe to provide sustained market confidence
2. Expanded program offerings that reflect consumer and electricity system needs

3. Objectives and targets for beneficial electrification programs, consumer education and capacity building
4. Feasibility and design options for demand flexibility (reducing, increasing or time shifting customer load) and distributed energy resource programs
5. Enhanced involvement of LDCs to help meet customer and electricity grid needs
6. Continuing programs for income-eligible residential customers and Indigenous communities
7. Improving the participant experience through enhanced electricity and natural gas energy-efficiency program coordination

Figure 21 shows the total maximum achievable savings potential in the West zone according to segmentation (residential, commercial, and industrial). As the 2022 APS forecast ends in 2042, energy savings in 2043 are assumed to be the same as 2042.

Figure 21 | Maximum Achievable eDSM Potential in the West Transmission Zone



For the identified needs in the Windsor-Essex region for which eDSM was screened in as a potential solution, these rates of savings potential are applied to each of the demand forecasts to determine the achievable eDSM savings. Figure 22 depicts the eDSM potential for Lauzon TS DESN 2, which is estimated to reach 11 MW based on the summer forecast.

Figure 22 | Estimated Incremental eDSM Potential at Lauzon TS DESN 2

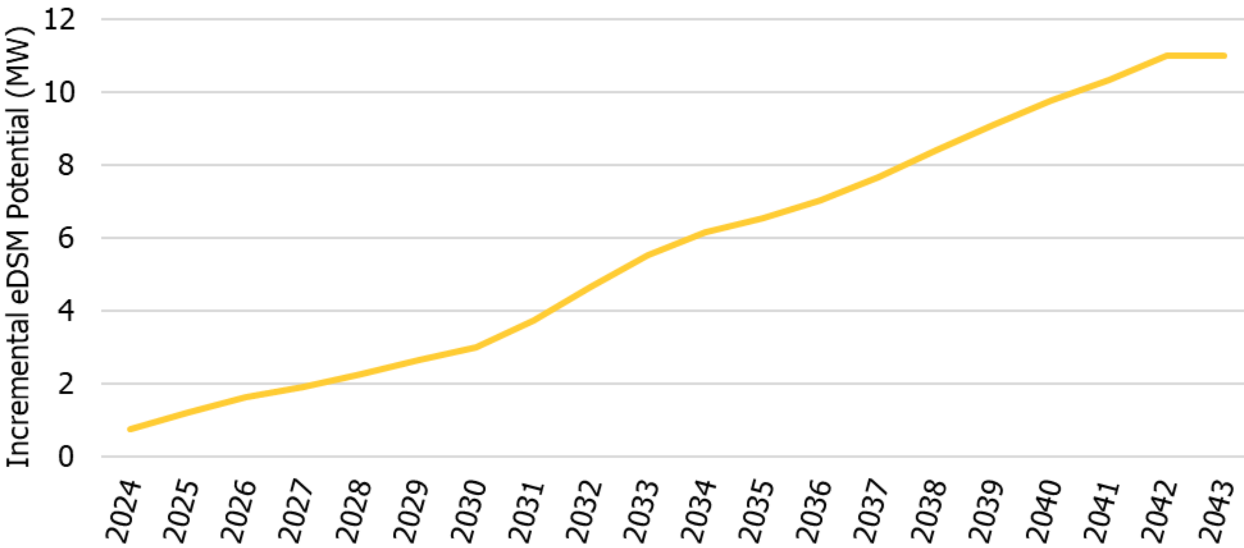


Figure 23 shows the eDSM potential for the West Essex and Windsor industrial developments based on the summer forecast, up to 9 MW by 2043.

Figure 23 | Estimated Incremental eDSM Potential for West Essex and Windsor Industrial Developments

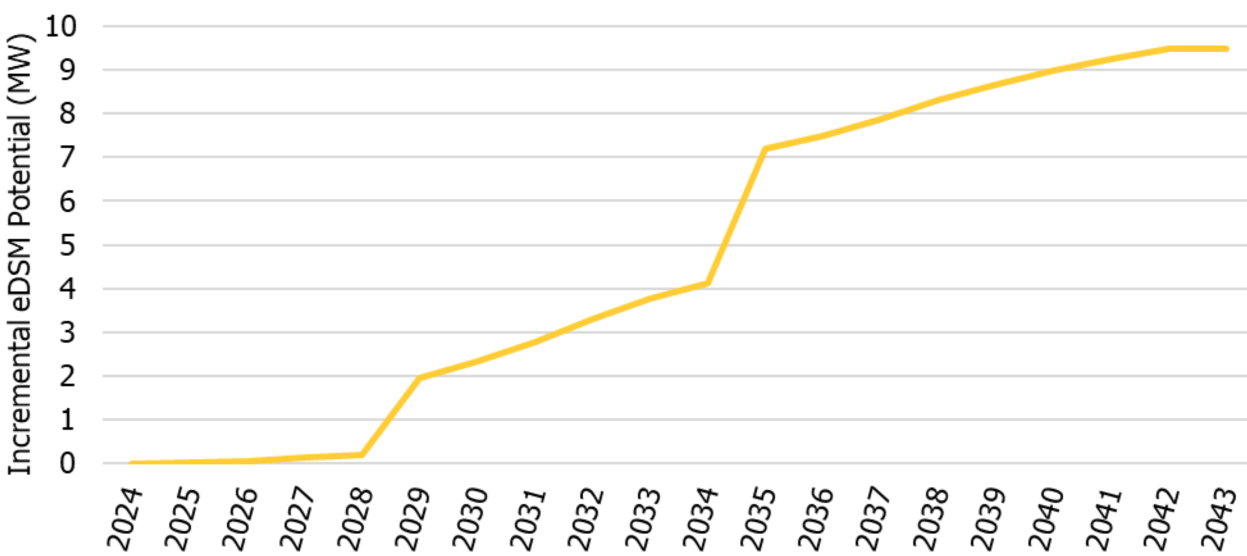


Figure 24 shows the eDSM potential for the Kingsville-Leamington greenhouse loads, including new greenhouse developments and loads at existing stations Kingsville TS, Leamington TS, and South Middle Rd TS. This potential reaches 100 MW over the forecast period based on winter demand forecasts.

Figure 24 | Estimated Incremental eDSM Potential for Kingsville-Leamington Greenhouse Loads

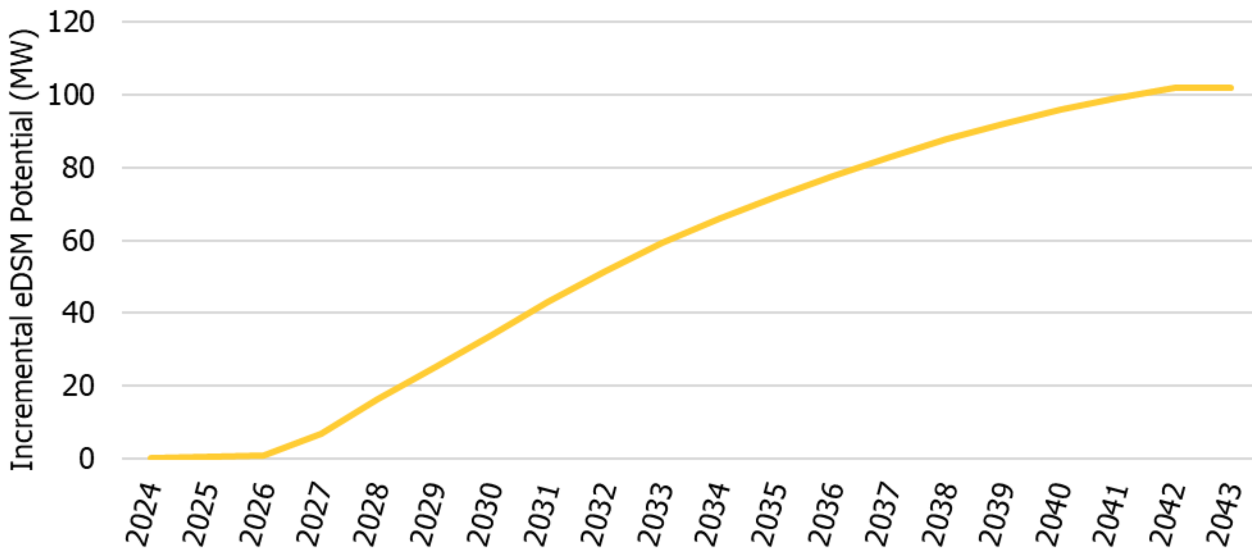


Figure 25 shows the eDSM potential at Belle River TS, forecast to reach five megawatts based on the summer need. However, past eDSM programs in this area have had less than expected impact, reflecting challenges targeting programs to relatively small areas and predominantly residential load composition. Consequently, there is a higher level of uncertainty with forecast.

Figure 25 | Estimated Incremental eDSM Potential at Belle River TS

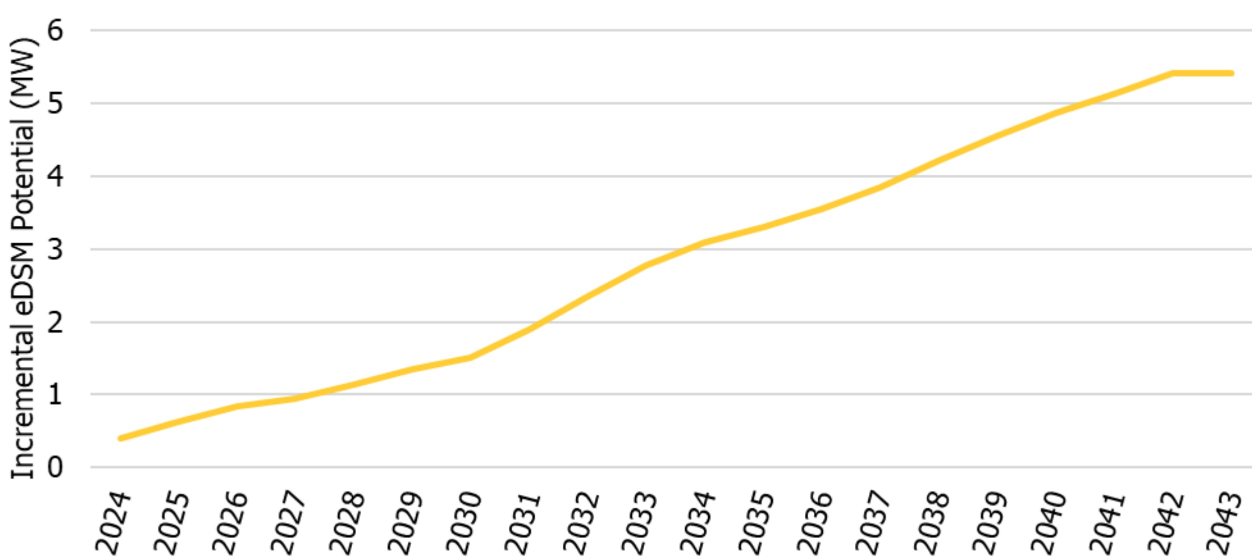
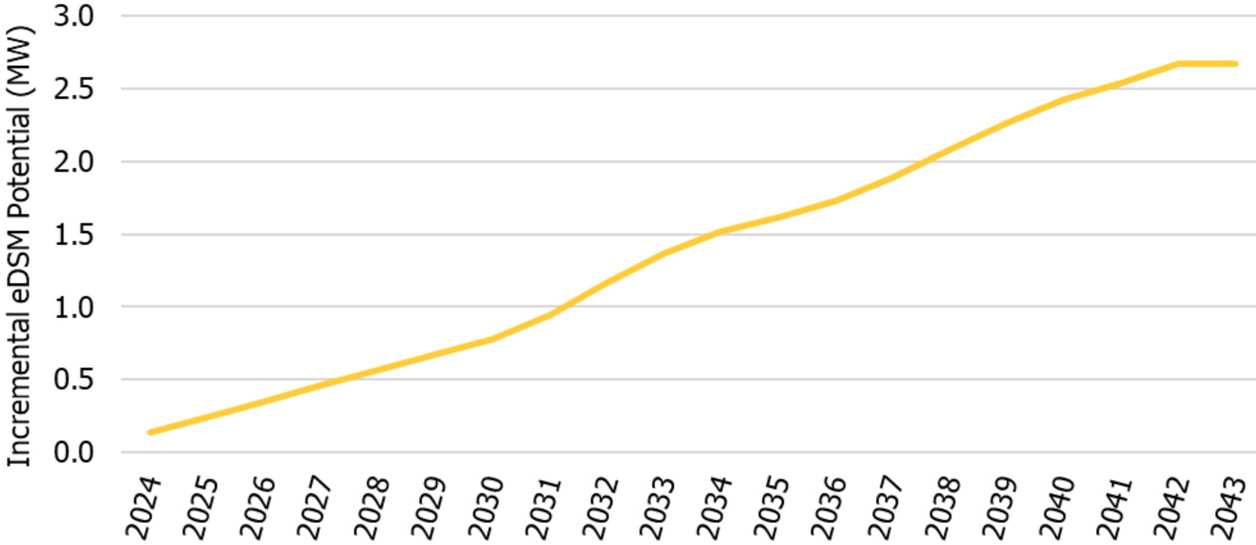


Figure 26 shows the achievable potential at Tilbury West DS based on the maximum achievable potential in summer and winter each year. Based on these forecasts, the eDSM potential is estimated to reach three megawatts over the IRRP forecast period.

Figure 26 | Estimated Incremental eDSM Potential at Tilbury West DS



Appendix F. Assumptions Used in Options Analysis

The following subsections provide a list of the assumptions made in the options analysis.

F.1 General Assumptions

The following assumptions apply to all economic analyses:

- All capital costs are expressed in 2024 CAD.
- The assessment was performed from an electricity consumer perspective and included all costs incurred by project developers, which were assumed to be passed on to consumers.

F.2 Transmission Assumptions

The following assumptions apply to wires options:

- Transmission build time: 5 to 10 years
- Station build time: 3 to 5 years
- The overnight cost of capital was used when NWAs were found to be infeasible to address needs.
- Overnight capital costs determined based on Class 5 cost estimates in the Leave to Construct application evidence on file with the Ontario Energy Board, benchmark transmission costs, as well as the input received from the transmitter. A Class 5 cost estimate is defined as having an accuracy of minus 50 per cent on the low side and plus 100 per cent on the high side. Wires cost estimates also vary depending on whether real estate rights need to be acquired or are already assigned to the transmitter.
    - New 230 kV single-circuit AC overhead line: $3M/km
    - New 230 kV double-circuit AC overhead line: $5M/km
    - New 500 kV single-circuit AC overhead line: $5M/km
    - New 115 kV or 230 kV DESN: $60M
    - Upsizing an existing 115 kV or 230 kV DESN: $15M to $30M
    - Station costs included diameters and autotransformers, as required, ranging from $4M to 17M.

F.3 Resource Assumptions

The following assumptions apply to non-wires options:

- Wind resource build time: 4 to 6 years
- Solar resource build time: 4 to 6 years
- Battery Energy Storage System (BESS) uses Lithium-ion technology
- BESS build time: 3 to 6 years
- BESS maximum storage size: 10 hours
- The solar and wind hourly profiles are sourced from IESO databases when available; NREL data is used as a substitute when IESO database information is unavailable.

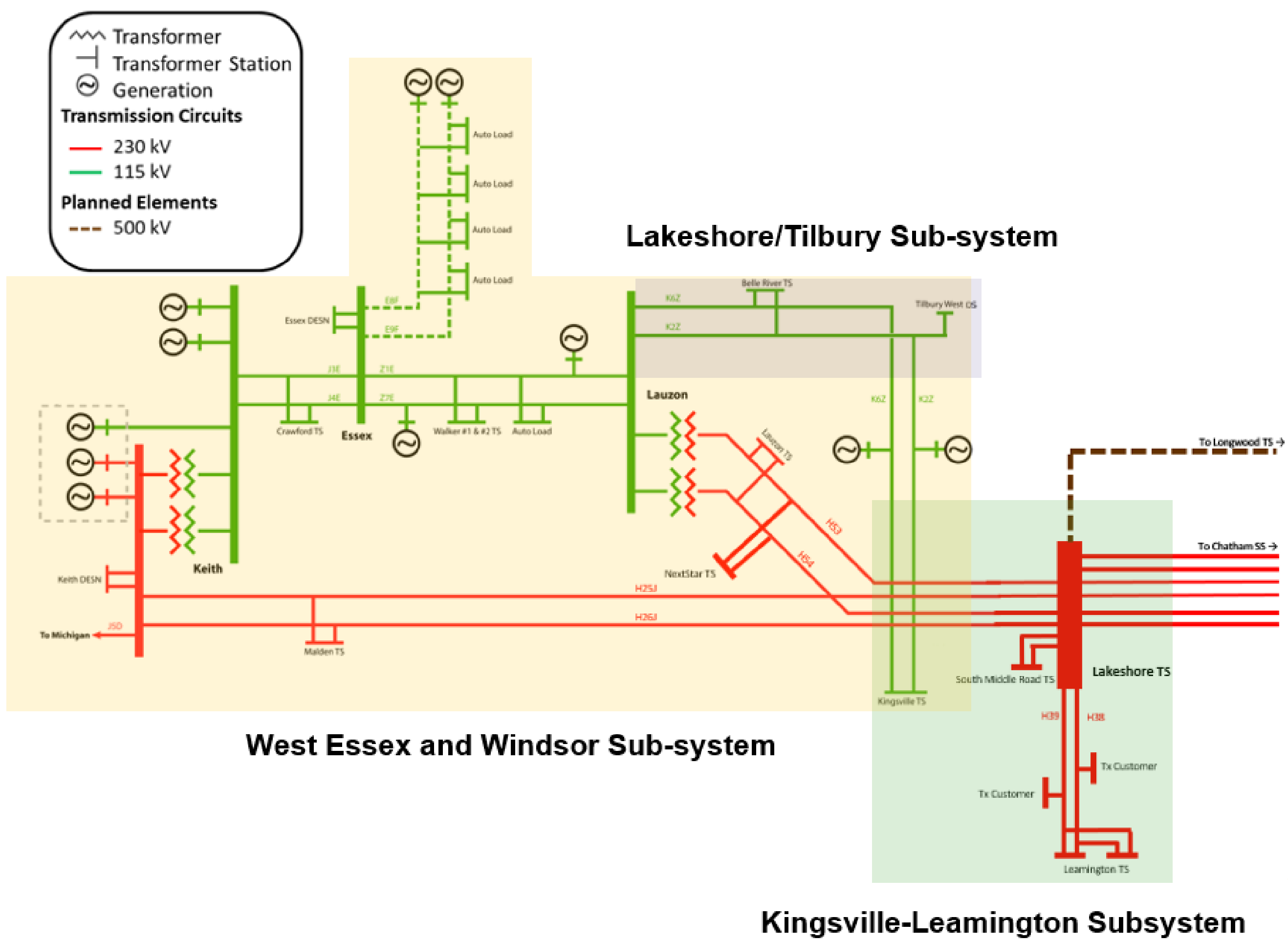
Appendix G. Windsor-Essex IRRP Technical Study

G.1 Description of Study Area

The Windsor-Essex region, as shown in Figure 27, consists of three sub-systems identified for this study:

1. West Essex and Windsor sub-system
2. Kingsville-Leamington sub-system
3. Lakeshore/Tilbury sub-system

Figure 27 | Single Line Diagram of the Windsor-Essex Region



G.2 Study Methodology

The IRRP load flow studies first identified system limitations and the impact (or sensitivity) factors of loads that influenced the limitation. This was done by using fictitious loads to stress the load pockets and sub-systems in isolation and simultaneously to derive a general set of equations to describe the limitations. The IRRP planning forecast and generation conditions were then used to identify if/when a given limitation would be triggered. Using this approach, it was possible to determine how a given limitation would behave under different conditions (e.g., high load or high generation conditions). To validate the approach, load flow studies were conducted for the forecast years to simulate the expected load flows under those conditions.

G.3 Scenarios Assessed

Table 4 summarizes the scenarios assessed. All scenarios assume peak load conditions, consistent with the IRRP Planning Forecast. No imports or exports were considered on the interconnections between Ontario and Michigan.

Table 4 | Summary of Scenarios Assessed

Scenario	Season	Contingencies Assessed
Reference, all in-service	Summer	N-1, N-2
Reference, outage	Summer	N-1-1, N-1-2
Reference, all in-service	Winter	N-1, N-2
High, all in-service	Summer	N-1, N-2

G.3.1 Load Forecast

The coincident net peak Planning Forecast snapshots for each of the planning forecast years up to end of planning horizon in 2043 were used in the study. The final peak demand forecast, by station, for each of the study years used in the base case is provided in Appendix B.11. A power factor of 0.9 was assumed, except for stations that supply greenhouse load where a 0.95 power factor was assumed instead.

G.3.2 Local Generation Assumptions

Renewable generation was assumed to be proportional to the zonal median capacity contribution for the given resource (e.g., solar or wind) providing a total of approximately 160 MW of local generation in the Windsor-Essex Region. BESS were assumed to be 75 per cent of the installed capacity, totalling approximately 70 MW. Gas resources were assumed to provide flexible dispatch while respecting their effective capacities. Total gas contribution at start of study period is approximately 730 MW. The gas contribution was adjusted over the study period based on contract term, completed resource procurements, and federal mandates. Distribution-connected generation was already accounted for in the load forecast, based on summer peak contribution factors.

G.3.3 Major Interface Flows

Transfers on the bulk system and imports/exports on the Michigan-Ontario interconnections were out of scope of regional planning. However, these flows were monitored to ensure they remained within limits. The relevant bulk transfer affecting the Windsor-Essex region is the Buchanan-Longwood Input flow and its observed pre-contingency ranged from 300 MW to 1,300 MW over the 20-year study period. Pre-contingency flows across the Ontario-Michigan interconnections were kept near zero.

G.4 System Topology

G.4.1 Remedial Action Schemes

The available remedial action schemes in the study region are listed below. When permissible according to ORTAC, these will be used first and foremost when any needs are identified by the studies.

- Windsor Area Remedial Action Scheme (RAS): Lauzon Load Rejection (LR) Scheme & Windsor Generation Rejection (GR) Scheme
- Lakeshore RAS Scheme
- Kingsville Voltage-Dependent LR Scheme

G.5 Criteria and Standards

G.5.1 Planning Criteria

The study will use the planning criteria in accordance with events and performance as detailed by:

- NERC TPL-001-5.1 "Transmission System Planning Performance Requirements";
- NPCC Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System"; and
- IESO ORTAC.

G.5.2 Studied Contingencies

Table 5 shows the types of contingencies assessed and how they map to applicable standards. The table also specifies the amount of LR or curtailment allowed per ORTAC.

Table 5 | Type of Contingencies Assessed

Pre-Contingency	Contingency[4]	Type	Mapping to TPL/Directory 1 Event	Rating[5]	Maximum Allowable Load Loss
All elements in-service	None	N-0	P0	Continuous	None
All elements in-service	Single	N-1	P1, P2	LTE	150 MW by configuration
All elements in-service	Double	N-2	P7, P4, P5	LTE	150 MW by curtailment; 600 MW total
All transmission elements in-service, local generation out-of-service (ORTAC 2.6)	None	N-0	N/A	Continuous	None
All transmission elements in-service, local generation out-of-service (ORTAC 2.6)	Single	N-1	P3	LTE	150 MW by configuration; >0 MW lost by curtailment;[6] 150 MW total
All transmission elements in-service, local generation out-of-service (ORTAC 2.6)	Double	N-2	N/A	LTE	>150 MW lost by curtailment;[6] 600 MW total
Transmission element out-of-service, followed by system adjustments	Single	N-1-1	P6	LTE	150 MW lost by curtailment; 600 MW total
Transmission element out-of-service, followed by system adjustments	Double	N-1-2	Cat II	LTE	N/A

Transmission system ratings were applied as follows:

- Transmission system loading for the loss of a double contingency can go up to short- term emergency (STE) ratings if there are control actions that can be used to reduce it to long-term emergency (LTE) ratings within the allotted time. If no control actions exist in the area, then LTE ratings should not be exceeded.

[4] Single contingency refers to a single zone of protection: a circuit, transformer, or generator. Double contingency refers to two zones of protection, the simultaneous outage of two adjacent circuits on a multi-circuit line, or breaker failure.

[5] LTE: Long-term emergency rating. 50-hr rating for circuits, 10-day rating for transformers.
STE: Short-term emergency rating. 15-min rating for circuits and transformers.

[6] Only to account for the magnitude of the generation outages.

- LTE rating should not be exceeded for the loss of a single contingency with the largest local generator out of service.
- Transmission system loading under outage conditions for the loss of a single contingency can go up to STE ratings if there are control actions that can be used to reduce it to LTE ratings within the allotted time. If no control actions exist in the area, then LTE ratings should not be exceeded.

G.6 Study Results

The following section provides the overall findings of the system studies beyond the station capacity needs discussed in the IRRP report. Further details on these assessments can be made available upon request, subject to confidentiality. These assessments were conducted assuming existing regional infrastructure and previously recommended bulk transmission infrastructure.

G.6.1 Summary of Existing System Study

Table 6 provides a summary of the planning criteria violations for the existing system study results discussed in the above subsections. Appendix G.6.2 provides the study results for wires and transmission-connected generation options to mitigate the violations; in particular, the criteria violations predicted on the West Essex and Windsor sub-system.

Thermal and voltage concerns have been identified within the West Essex and Windsor sub-system. Thermal concerns on the circuits between Lakeshore TS and Lauzon TS with all elements in service and under outage conditions, as well as thermal overloads under outage conditions on the 115 kV circuits between Lauzon TS and Essex TS and the 230 kV circuits between Lakeshore TS and Keith TS. Voltage decline and voltage drop concerns are observed at Lauzon TS.

Other sub-systems are not forecast to experience planning criteria violations according to the Planning Forecast, but have other needs as discussed in Section 6 of the IRRP report. In the Kingsville-Leamington sub-system, additional greenhouse load not associated with a connection station has been assumed to connect directly at Lakeshore TS. Studies confirm that there are no concerns supplying these loads at Lakeshore TS, assuming a voltage dependent load model.

In the Lakeshore/Tilbury sub-system, no thermal issues beyond the station capacity needs were identified considering the Planning Forecast. Under the High Forecast, there is a thermal limit on the 115 kV transmission path.

Table 6 | Summary of Windsor-Essex Existing System Study Results

Sub-system	Conditions	Violation	Year	Mitigation
West Essex and Windsor	Summer Reference, all in-service	Thermal limitation from Lakeshore TS to Lauzon TS	2032	IRRP recommendation is required.
West Essex and Windsor	Summer Reference, all in-service	Lauzon 230 kV voltage decline and collapse	2036	IRRP recommendation is required.

Sub-system	Conditions	Violation	Year	Mitigation
West Essex and Windsor	Summer Reference, one Keith TS to Essex TS circuit out of service	Thermal limitation from Lakeshore TS to Lauzon TS	2031	Resolved with 60 MW of LR until 2033. After 2033, the violation emerges under all in-service conditions. IRRP recommendation is required.
West Essex and Windsor	Summer Reference, one Lakeshore TS to Lauzon TS circuit out of service	Thermal limitation from Keith TS to Essex TS	2023	Resolved with 120 MW of LR.
West Essex and Windsor	Summer, Reference, one Lakeshore TS to Lauzon TS circuit out of service	Thermal limitation from Lakeshore TS to Keith TS	2034	Resolved with 750 MW of LR until 2039. IRRP recommendation is required.
West Essex and Windsor	Summer Reference, one Lakeshore TS to Lauzon TS circuit out of service	Thermal limitation from Lakeshore TS to Lauzon TS	2031	Resolved with 90 MW of LR until 2033. IRRP recommendation is required.
Kingsville-Leamington	Summer, Reference, all in-service	Kingsville 115 kV voltage decline and collapse	2041	Resolved with 40 MW of LR.
Kingsville-Leamington	Winter, Reference, all in-service	Leamington TS low-tension per cent voltage drop	2038	Resolved assuming voltage dependent load modelling.
Kingsville-Leamington	Winter, Reference, all in-service	SMR TS low-tension per cent voltage drop	2038	Resolved assuming voltage dependent load modelling.

G.6.2 Options Analysis – West Essex and Windsor Supply Capacity Need

This section presents the technical study results to address the planning criteria violation for the West Essex and Windsor sub-system. Studies were conducted assuming summer all in-service conditions and static generation output reflective of contract terms. The available capacity in this sub-system depends on where load materializes, with the Lauzon TS 230 kV bus being the most restrictive element. With no reinforcements, under the high forecast scenario a thermal overload on Lakeshore TS to Lauzon TS emerges in 2024.

Three wires options and one non-wires option were explored:

1. Single-circuit 230 kV line from Lakeshore TS to Lauzon TS.
2. Double-circuit 230 kV line from Lakeshore TS to Lauzon TS.
3. Single-circuit 500 kV line from Lakeshore TS to Lauzon TS.
4. Transmission-connected generation.

Option 1: Single-circuit 230 kV line from Lakeshore TS to Lauzon TS

This option considers the ability of a single-circuit 230 kV line from Lakeshore TS to Lauzon TS to meet the West Essex and Windsor supply capacity need. During the all in-service condition, no thermal or voltage concerns have been identified within the Windsor-Essex region with the addition of a single-circuit 230 kV line from Lakeshore TS to Lauzon TS. In 2043, a one per cent post-contingency overload on the Lakeshore TS to Lauzon TS path emerges following the loss of one circuit between Lakeshore TS and Lauzon TS and one circuit between Lakeshore TS and Keith TS; however, this violation is resolved with under load tap changer (ULTC) action.

In 2043, under outage conditions a three per cent overload emerges on the Lakeshore TS to Keith TS path following the same contingency as all in-service conditions. This may be reduced to one per cent by arming 39 MW of LR via the Windsor Area RAS.

During the same outage condition in 2043, an 18 per cent overload was seen on the Lakeshore TS to Lauzon TS path following the loss of both 230 kV circuits between Lakeshore TS and Keith TS. This may be fully mitigated with 150 MW of LR via the Lakeshore RAS. The most limiting contingency affecting the H54 circuit becomes the loss of the single line of the reinforcement itself, which overloads the H54 section to 37 per cent. The overland can be reduced to six per cent by applying the Lakeshore RAS. An additional 39 MW of LR via the Windsor Area RAS can further reduce the overload to one per cent; however, this would violate the planning criteria, which limits arming of LR to 150 MW. Despite these limitations, the single-circuit 230 kV line from Lakeshore TS to Lauzon TS represents a significant improvement with respect to the overload observed without the reinforcement as previously discussed.

Considering the High Forecast with the single-circuit 230 kV Lakeshore to Lauzon circuit reinforcement, an thermal limitation on Lakeshore TS to Lauzon TS emerges in 2028. Importantly, it was assumed the single-circuit reinforcement did not create a new double contingency. This means the new circuit does not share a common breaker or a common right of way with shared towers, such that the new circuit may be lost along with any of the existing circuits between Lakeshore TS and Lauzon TS. This would be significantly more limiting, as it would equivalent to the current system with no reinforcement followed by the loss of a single circuit between Lakeshore TS and Lauzon TS.

Table 7 provides a summary of the system studies with the single-circuit 230 kV Lakeshore to Lauzon reinforcement.

Table 7 | Summary of System Study Results in 2043 – Option 1

Condition	Violation	Pre-ULTC Violation?	Contingency	Mitigation
All in-service	None	No	n/a	n/a
All in-service	1% thermal overload on Lakeshore TS to Lauzon TS	Yes	Double 230 kV circuits	ULTC action
One Lakeshore TS to Lauzon TS circuit out of service	37% thermal overload on Lakeshore TS to Lauzon TS	No	New Line	LR of transmission-connected load and 25 per cent of local TS

Option 2: Double-Circuit 230 kV line from Lakeshore TS to Lauzon TS

This option considers the ability of a double-circuit 230 kV line from Lakeshore TS to Lauzon TS to meet the West Essex and Windsor supply capacity need. Studies were conducted assuming summer all in-service conditions and static generation output reflective of contract terms. Under the Planning Forecast, no thermal or voltage concerns were identified.

The High Forecast was used to understand further stress studies and understand the limitations of this option. Similar to the Planning Forecast, the Lauzon TS 230 kV bus is the most impactive element for this interface. With the addition of a double-circuit 230 kV line from Lakeshore TS to Lauzon TS, the thermal overload on Lakeshore TS to Lauzon TS emerges in 2031 under the High Forecast scenario. This is three years later than with the addition of a single-circuit 230 kV line. The double-circuit 230 kV line provides 510 MW of additional capacity, which is 150 MW more than the single-circuit line.

Option 3: Single 500 kV line from Lakeshore TS to Lauzon TS

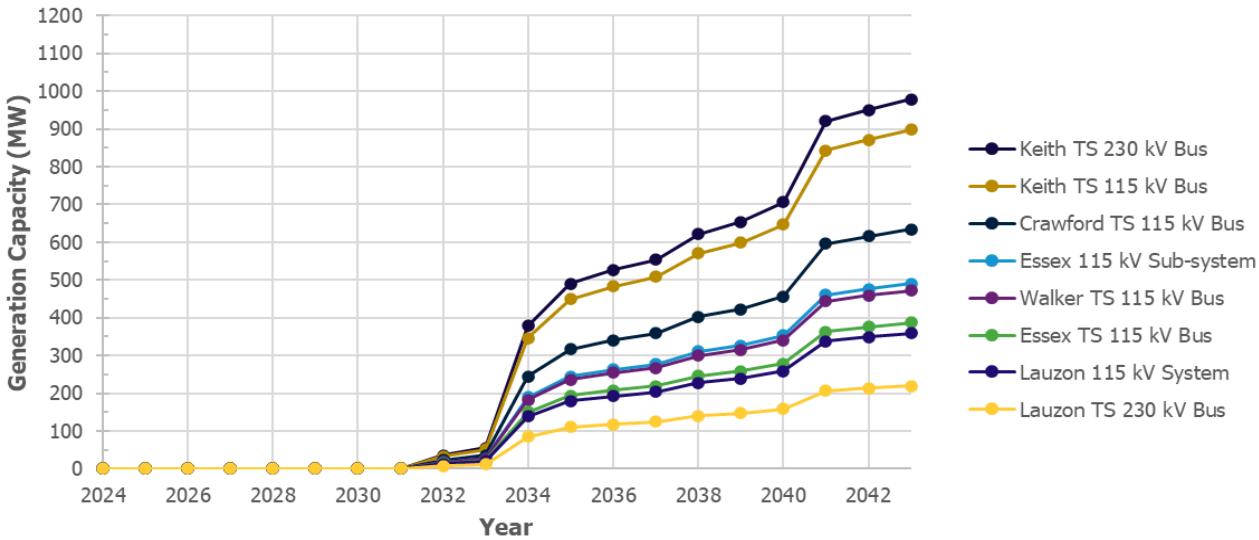
This option considers the ability of a single-circuit 500 kV line from Lakeshore TS to Lauzon TS to meet the West Essex and Windsor supply capacity need. It was determined this option had similar capacity improvement as Option 2. This is because the single contingency of the reinforcement is the most limiting, resulting in the same post-contingency topology and overload. Therefore, aside from differences under outage conditions and all in-service post-contingency criteria, these two reinforcement options are equivalent from a supply capacity perspective. Refer to the IRRP report for comparison of other factors which outline why the double-circuit 230 kV Lakeshore TS to Lauzon TS reinforcement is preferable.

Option 4: Transmission-Connected Generation

This option considers the ability of transmission-connected generation to meet the West Essex and Windsor supply capacity need. The required generation to resolve the thermal overload on Lakeshore TS to Lauzon TS was estimated when performing the study and varies based on location as shown in

Figure 28. The graph shows that the optimal location to connect the generation would be the Lauzon TS 230 kV bus. By the end of the planning forecast, approximately 230 MW of generation capacity at the Lauzon TS 230 kV bus would be required to address the need.

Figure 28 | Generation Requirements to Mitigate West Essex and Windsor Supply Capacity Need at Various Locations



Summary of Options

Table 8 compares each of the transmission options. The single-circuit 230 kV line from Lakeshore TS to Lauzon TS enables 360 MW of growth beyond the current system. Both the double-circuit 230 kV line and the single-circuit 500 kV line from Lakeshore TS to Lauzon TS enable 510 MW of growth beyond the current system. In comparison, 230 MW of generation connected to the Lauzon TS 230 kV bus can meet the Planning Forecast need without providing additional capacity beyond the forecast. Section 7 of the IRRP report evaluates these wires and non-wires options.

Table 8 | Summary of Transmission Options Comparison for the West Essex and Windsor Supply Capacity Need

Option	Post-Contingency Thermal Overload	Planning Forecast Need Year	High Forecast Need Year	Growth Enabled Beyond Current System
None	Lakeshore TS to Lauzon TS	2032	2024	-
Single-circuit 230 kV Lakeshore TS to Lauzon TS line	Lakeshore TS to Lauzon TS	2044	2028	360 MW
Double-circuit 230 kV Lakeshore TS to Lauzon TS line	Lakeshore TS to Lauzon TS	-	2031	510 MW

Option	Post-Contingency Thermal Overload	Planning Forecast Need Year	High Forecast Need Year	Growth Enabled Beyond Current System
Single-circuit 500 kV Lakeshore TS to Lauzon TS line	Lakeshore TS to Lauzon TS	-	2031	510 MW