London Area Integrated Regional Resource Plan

DRAFT

Draft Forecast Methodology Document

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Demand Forecast Methodology

The demand forecast methodology follows the following steps, which are detailed in this document.

1. Forecast Starting Point Creation
2. Scope of Demand Forecast Scenarios
3. Median-Weather Gross Demand Forecasts
4. Forecasted Distributed Generation
5. Electricity Demand Side Management Assumptions
6. Forecasted Extreme Temperature
7. Final Peak Forecast by Station

1. Forecast Starting Point Creation

The forecast starting point is the historical demand for a representative reference year (2024 for the London Area IRRP) on which Local Distribution Companies (LDCs) build their gross demand forecasts.[1]

To produce the forecast starting point for LDCs, the IESO must first unbundle existing distributed generation (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[2] is added back onto the measured historical net demand of stations. The weather-normalization methodology is discussed in the following subsection 1.1. 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 Ontario Energy Board through the Regional Planning Process Advisory Group.

The Technical Working Group (TWG) decided to use regional-coincident peak demands for the starting points and for the gross forecasts produced by the LDCs. This decision was motivated by the frequently used load transfer capability between the stations within the Greater London sub-region.

The TWG also decided to use the 2024 weather-normalized demand as the starting point of the forecast, rather than an average of historical years. This was due to new growth trends in the region and due to potential anomalies in 2020-2022 resulting from the COVID-19 pandemic.

[1] A gross forecast means that existing and new distributed generation, and new electricity demand side management savings are not accounted for in the forecast. Once distributed generation and electricity demand side management savings 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.

[2] 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 facilities.

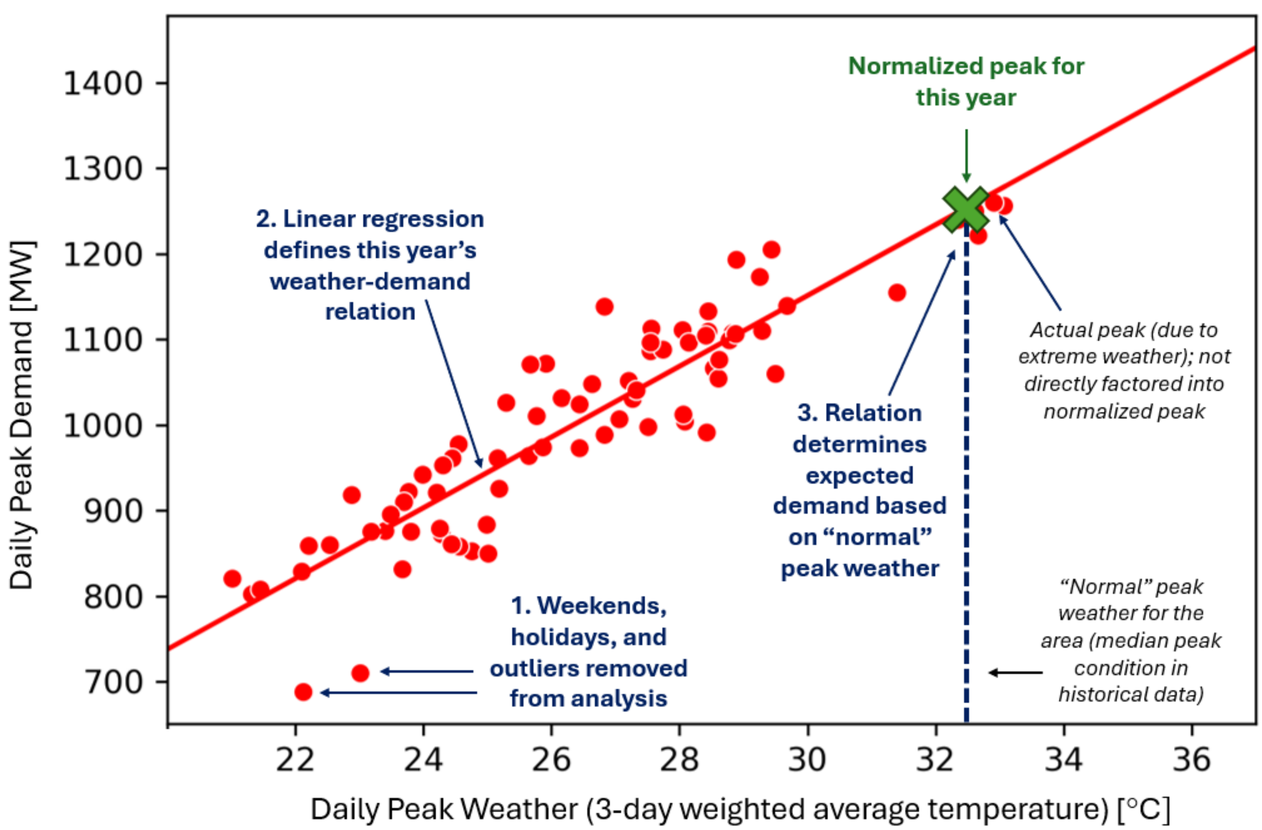
1.1 Method for Accounting for Weather Impact on Demand

Weather has a large influence on the demand for electricity, so to develop a standardized starting point for the forecast, the historical electrical demand is weather-normalized. This section details the 3-step weather normalization process that is used.

Weather normalization is determined separately for each historical year. This is to allow for changes in the weather sensitivity from one year to the next. The previous 5 years were analysed, 2020 to 2024, and the summer and winter seasons were analysed separately for each year. The daily peak demand is collected for each year and season. For the summer season, the daily peak demand is plotted against a 3-day weighted average of daily *maximum* temperature. For the winter season, it is plotted against a 3-day weighted average of daily *minimum* temperature.[3] Then the following process is used, which is illustrated in **Figure 1**.

1. Weekends, holidays, and outliers are removed.
2. A linear regression is performed.
3. The regression line is evaluated at the median temperature for the season.[4] The resulting value is used as the starting point for the year and season.

Figure 1 | Method for Determining the Weather-Normalized Peak (Illustrative)



[3] Humidex and wind chill were also considered for weather sensitivity, rather than temperature. But in order to incorporate temperature forecasts into the demand forecast, temperature was selected as the weather variable. For more details, please see Section 6.

[4] The median temperature for the season is found by taking the 30-year median of the annual worst 3-day weighted average temperature. For summer, worst means the maximum temperature; and for winter, worst means the minimum temperature.

The TWG decided to use regional-coincident peak demands for the starting points. As a result, the above-mentioned process was applied to the peak demand for the London Area region. In order to produce the starting points for the stations, the actual (non-weather-normalized) coincident station peak demand was multiplied by the ratio of the regional starting point divided by the actual regional demand.

2. Scope of Demand Forecast Scenarios

The TWG agreed to develop multiple forecast scenarios, as is the recent standard for several IRRPs, in an effort to make plans adaptable to changes that may occur in the demand forecast between planning cycles.

In the London Area region, forecasted demand growth is primarily driven by industrial loads, which are particularly sensitive to economic circumstances. With the large potential for economic growth in the long term, and with the likelihood of negative economic impacts from geopolitical factors in the short term, the TWG saw value in preparing both high and low growth scenarios. As a result, the TWG has produced a reference demand forecast and two additional scenarios for consideration in this IRRP. The guideline for the reference forecast and two scenarios is provided below in **Table 1**.

Table 1 | Demand Forecast and Scenarios Guideline

Consideration	Reference Forecast	High Growth Scenario	Low Growth Scenario
Certainty of Project or Driver[5]	Reasonably certain	Could reasonably happen	Reasonably certain, but slower pacing or impact
Pacing of Load Buildup for Firm Requests[6]	As provided to LDCs	As provided to LDCs	Delayed or reduced
Pacing of Drivers	As provided to LDCs, or existing historical trends	As provided to LDCs, or highest historical trends	Low scenarios used when provided to LDCs, or lower historical trends
Demand Factors[7]	Average or mid-range values	Upper-range values	Lower-range values

[5] Driver refers to any input into the forecast that cannot be tied to a specific project, such as housing forecasts.

[6] Firm requests refer to confirmed load connection requests to the LDCs.

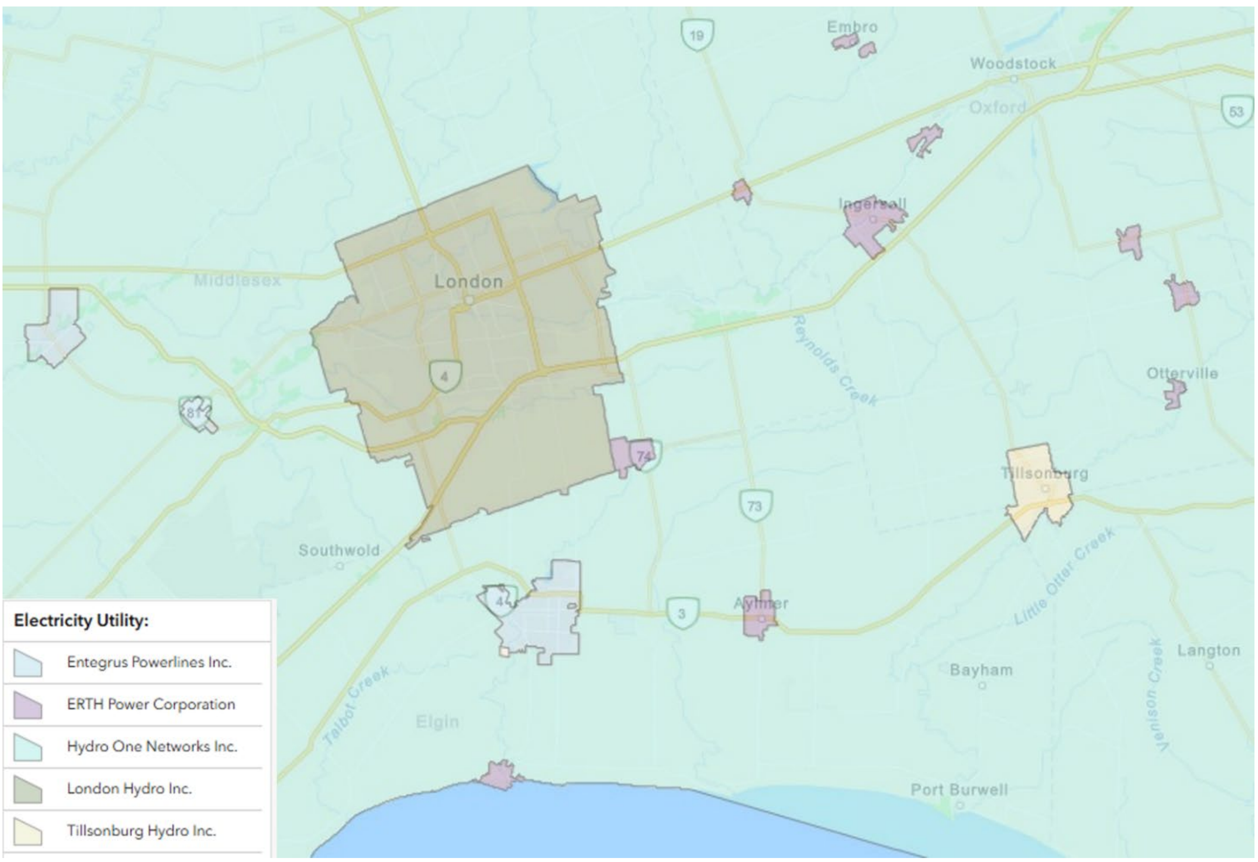
[7] Demand factors refer to any assumptions which translates quantities to electrical demand, such per-unit kW demand (ex kW/EV) or coincidence factors.

3. Median-Weather Gross Demand Forecasts

Each of the five LDCs in the London Area TWG provided their own reference forecast and scenarios for their own loads, corresponding to their service territories as illustrated in Figure 2. Forecasts and scenarios were provided as gross demand and assuming normal weather. Generally, the LDCs considered the same drivers and aligned forecasting assumptions, as detailed in Section 3.1. However, each LDC considered what was most appropriate for their customer base and their own historical trending, ultimately arriving at an IRRP forecast which reflects some uniqueness across the sub-regions. Sections 3.2 to 3.6 outline the variations in methodology used by each LDC.

For brevity, the use of the word “forecast” in the following sections will refer to both the reference forecast and the high and low growth scenarios, unless stated otherwise.

Figure 2 | Map of the LDC Service Areas within the London Area Region



3.1 Common Drivers and Assumptions

The TWG identified five drivers for demand growth which were common to the LDC forecasts: firm requests, industrial/commercial/institutional (IC&I) loads[8], housing, electric vehicles, and electric heating. While electric heating was considered for winter demand, the region is forecasted to remain summer peaking, and this largely remains true for all stations. There are two exceptions to this, only occurring under the high growth scenario and in the long-term (>10 years).[9]

[8] The IC&I loads driver refers to additional ICI growth that is not already present as firm requests.

[9] For the high growth scenario, Edgeware TS and Strathroy TS have long-term (>10 years) winter needs exceeding summer needs.

3.1.1 Firm Requests

Most of the LDCs used firm requests[10] for connection to their system as an input into their forecast. Most often the requested demand is weighted down to 50-75%, due to factors such as overestimation and coincidence with the station peak. This factor was based on historical trends within each LDC's customer base.

3.1.2 IC&I Loads

The IC&I loads driver refers to additional IC&I loads that are not already included in firm connections. This anticipates future IC&I load growth that has not yet been formally requested. Every LDC considered IC&I load growth as an input into their forecast.

This driver had the largest level of uncertainty in terms of demand impacts, as the IC&I sector can range from low-intensity buildings such as warehousing and storage, to high-intensity buildings such as data centres. As a result, the LDCs considered variations to both demand impacts and the volume of IC&I connection requests in their forecasts. For the reference forecast, LDCs assumed a demand impact in the range of 15-35 kW/m^2 of gross floor area. Demand impacts spanned 5-35 kW/m^2 for the low scenario, and 25-100 kW/m^2 for the high scenario.

Forecasts for the volume of IC&I connection requests were largely informed by municipal input, with many municipalities providing gross floor area forecasts and citing plans for industrial parks. Input based on engagement with developers and historical trending of customer connections were also used.

3.1.3 Housing

Every LDC considered growth in housing as an input into their forecast. Housing forecasts provided by municipalities and historical highs and lows in new residential connections were used to forecast the quantity of new residential connections. For the reference forecast, LDCs assumed a demand impact in the range of 2.0-2.5 kW per home. Demand impacts spanned 1.0-2.1 kW for the low scenario, and 2.1-3.3 kW for the high scenario.

3.1.4 Electric Vehicles

Every LDC considered electric vehicles as an input into their forecast. The LDCs took different approaches to estimating electric vehicle (EV) adoption[11] over the forecast period, which is discussed in the following LDC-specific subsections. However, each LDC leveraged historical EV registration data from the Ontario Ministry of Transportation for their service territory, and used this to estimate existing population and current growth trends for EVs.

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[10] A firm request is a committed connection request from a customer to an LDC, typically with a signed contract.

[11] EV adoption refers to the total number of EVs in use divided by all vehicles in use.

Initially, most LDCs were assuming a high adoption of EVs in the short and medium term (years 1-10 of the forecast), based on Canada's Electric Vehicle Availability Standard. However, over the course of the summer of 2025, several developments (listed below) suggested that this assumption was no longer reasonable. As a result, most LDCs delayed their assumptions on EV adoption in the short and medium term, with some continuing a delayed adoption into the long term. Details are specific to each LDC and are described in the following LDC-specific subsections.

- The EV market share in Ontario was 7.4% of new sales in 2024, below Canada-wide statistic of 13.8%, and would need a steep ramp up to meet the federal targets of 20% in 2026.
- Zero emission vehicles were less than 5% of total new vehicles registered in Q1 2025 in the London Census Metropolitan Area, well below the federal target of 20% in 2026.
- Articles[12,13] of automakers urging the repeal of Canada's Electric Vehicle Availability Standard due to feasibility concerns.
- The Parliamentary Budget Office found that the federal sales targets are not attainable without significant further reductions in EV costs.
- Prime Minister Mark Carney delayed Canada's Electric Vehicle Availability Standard, and waived the Standard for 2026 models.

Similar to IC&I loads, there is a large level of uncertainty in demand impacts of electric vehicles, based on the various chargers available in the market and several EV guidelines available at this point in time. Based on this input and the characteristics of their customer bases, LDCs assumed a non-coincident demand impact in the range of 3.0-9.6 kW per EV, highlighting this uncertainty. Considering coincidence with the station peaks, the coincident demand impact assumed by most LDCs was in the range of 0.6-1.7 kW per EV in the reference forecast. Demand impact spanned 0.5-1.7 kW for the low growth scenario, and 0.8-2.4 kW for the high growth scenario. Tillsonburg Hydro Inc. was the exception to these ranges, for reasons described in Section 3.6.1.

3.1.5 Electric Heating

While electric heating was included in each LDC's forecast, each LDC took a unique approach. This was appropriate since electric heating is an emergent technology amongst the customer bases in the London Area region. As a result, the assumptions for electric heating will be described in the following LDC-specific subsections.

Based on a mix of research and small sample sets of existing heat pump adoption[14], LDCs assumed a non-coincident demand impact in the range of 3-6 kW per residence using a heat pump. Considering coincidence with the station peaks, the coincident demand impact assumed by most LDCs was in the range of 1.5-1.8 kW per residence using a heat pump.

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12 Automakers 'cautiously optimistic' after meeting Carney over EV mandates

13 Automakers want Canada to scrap its EV sales mandate. What would that do to emissions?

14 Heat pump adoption refers to the total number of buildings using heat pumps divided by all buildings.

3.2 London Hydro

London Hydro (LH) is the LDC supplying electrical demand within the City of London. LH's demand is supplied in part or entirely from the following stations: Buchanan Transformer Station (TS), Clarke TS, Highbury TS, Nelson TS, Talbot TS, and Wonderland TS. A small portion of demand (less than one megawatt) is also supplied from Edgeware TS. For a map of LH's service territory, please see **Figure 2** at the start of Section 3.

3.2.1 Forecast Methodology and Assumptions

LH considered all five of the common drivers in its forecast, using a blend of both econometric and end-use forecasting. Demand growth is primarily driven by IC&I load growth, followed by residential load growth associated with new housing.

LH only included particularly large firm requests in its forecast, such as the four listed below. In general, firm requests were captured through forecasting IC&I loads. To forecast IC&I loads, City of London geospatial economic growth data was leveraged, which provides new IC&I floor area. Included in this input is a 200-acre industrial park which has been incorporated into the forecast. LH also considered high-probability but not-yet firm customer inquiries when forecasting IC&I loads.

- Institutional customer #1: 80 MW
- Institutional customer #2: 30 MW
- Industrial customer #1: 10 MW
- Industrial customer #2: 120 MW

Similar to IC&I loads, LH used City of London geospatial economic growth data which provides new residential units to forecast housing loads. This includes approximately 83,000 new residential units over the next 20 years.

The City of London provided LH with its EV modelling data which includes multiple scenarios. LH leveraged this data to develop EV forecasts for its reference forecast and its high and low growth scenarios. However, based on the evidence for delayed EV adoption (discussed in Section 3.1.4) and with the IESO also forecasting a delayed adoption in its 2026 Annual Planning Outlook[15], LH adopted a lower EV adoption than most of the City of London's scenarios. Consequently, LH forecasted an adoption of 8-24% by 2034, and 9-55% by 2044, depending on the forecast scenario.

The City of London's Climate Emergency Action Plan (CEAP) was adopted by Council in April 2022, and references heat pump adoption as a key tool for achieving the City's greenhouse gas emissions targets. As a result, it was necessary for LH to include heat pump demand in its forecast to properly reflect City initiatives. The CEAP was also raised to the IESO in its Municipal Survey extended by the IESO to inform the IRRP.

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[15] See slide 8 of 2026 APO Electricity Planning Scenarios Presentation

However, the *Protect Ontario by Building Faster and Smarter Act, 2025* (Bill 17) enacted in June 2025, prevents municipalities from passing by-laws concerning construction or demolition of buildings (Schedule 1 (4) of the Act). As a result, performance standards or requirements that exceed the Ontario Building Code cannot be made into law. Because this mechanism is central to many municipal decarbonization strategies, the Act introduces major challenges to the feasibility of enforcing heat pump adoption in the short-to-medium term.

As a result, LH aligned heat pump adoption with the adoption forecasted in the Canada Energy Regulator's Canada's Energy Future (2023) for its high growth scenario, and used this to inform its assumptions for adoption under its reference forecast and low growth scenario. The reference forecast and low growth scenario were produced by applying offsets from the high growth scenario. These offsets vary across the near-term, medium-term, and long-term periods for each scenario. This allowed LH's forecast to still reflect the CEAP, while acknowledging likely delays to heat pump adoption resulting from the Act.

3.3 Hydro One Networks Inc. (Distribution)

Hydro One Networks Inc. (HONI) is the LDC supplying electrical demand in the City of Woodstock, a portion of the City of St. Thomas, and the majority of the following counties:[16] Elgin County, Middlesex County, Norfolk County, and Oxford County. HONI's demand is supplied in part or entirely from the following stations: Aylmer TS, Buchanan TS, Clarke TS, Commerce Way TS, Edgeware TS, Highbury TS, Ingersoll TS, Longwood TS, Strathroy TS, Tillsonburg TS, Wonderland TS, and Woodstock TS. For a map of HONI's service territory, please see **Figure 2** at the start of Section 3.

3.3.1 Forecast Methodology and Assumptions

HONI considered all five of the common drivers in its forecast, and used a combination of both econometric and end-use forecasting. Demand growth is primarily driven by firm requests and IC&I load growth.

HONI included several large firm requests in its forecast, as listed below. HONI used municipal plans, input from field staff, and input from developers to forecast its IC&I loads. Specific IC&I developments provided from municipal input include: the Yarmouth Yards industrial park in St. Thomas, the Molnar Industrial Park in Strathroy-Caradoc, up to 95 acres of industrial land development in Middlesex Centre over the long term, and up to 300 acres of industrial land development in Central Elgin over the long term.

- IC&I customer #1: 21 MW
- IC&I customer #2: 21 MW
- IC&I customer #3: 10 MW
- IC&I customer #4: 8 MW
- IC&I customer #5: 5 MW
- IC&I customer #6: 4 MW
- IC&I customer #7: 3.5 MW
- IC&I customer #8: 3.0 MW
- IC&I customer #9: 2.8 MW
- IC&I customer #10: 2.8 MW
- IC&I customer #11: 2.3 MW
- IC&I customer #12: 1.6 MW
- IC&I customer #13: 1 MW
- IC&I customer #14: 1 MW
- IC&I customer #15: 1 MW
- Residential complex #1: 6.2 MW
- Residential complex #2: 1.6 MW
- Residential complex #3: 1.3 MW

[16] To the extent that these Counties are included in the London Area Region, as these Counties also extend outside the Region

- Residential complex #4: 1 MW

To forecast housing loads, HONI used developer information for in-progress projects and municipal plans. Municipal input included: over 15,000 new residential units in the City of St. Thomas over 2021-2051, 6,000 new residential units in the Municipality of Strathroy-Caradoc over 2021-2046, over 6,000 new households in Thames Centre over the near to medium term, over 5,000 new residential units in Middlesex Centre over the long term, 2,000 new residential units in Southwold over the long term, and 1,500 new residential units in North Middlesex over the near to medium term.

HONI considered a combination of historical EV registration data, historical estimated EV demand in its service area, and government policies when forecasting EV adoption. Depending on the scenario, this resulted in an adoption of 31-36% in 2034 (10 years into the forecast), and 88-92% in 2044 (20 years).

HONI forecasted heat pump adoption based on its history of customers using heat pumps, although this set of customers is small resulting in much uncertainty. HONI also considered the potential for government policies in the future. HONI assumed heat pump adoption for both residential and IC&I customers, but only for new connections. For residential customers, this resulted in 10% of new connections by 2034, and 49% of new connections by 2044. For IC&I customers, this resulted in 5% of new connections by 2034, and 35% of new connections by 2044.

3.4 Entegrus Powerlines Inc.

Entegrus Powerlines Inc. ("Entegrus") is an LDC supplying electrical demand within the Strathroy, Mount Brydges, and Newbury communities within Middlesex County, and a portion of the City of St. Thomas. Entegrus's demand is supplied in part from the following stations: Edgeware TS, Longwood TS, and Strathroy TS. For a map of Entegrus's service territory, please see **Figure 2** at the start of Section 3.

3.4.1 Forecast Methodology and Assumptions

Entegrus considered all five of the common drivers in its forecast, and used a blend of both econometric and end-use forecasting to produce its forecast. Demand growth is primarily driven by IC&I load growth, followed by EV load growth.

Entegrus included firm requests in its forecast, with the largest requests listed below. To forecast IC&I demand growth, Entegrus used historical growth rates of IC&I demand growth (highest and average).

- Industrial/commercial customer #1: 2.5 MW
- Industrial/commercial customer #2: 1 MW
- Industrial/commercial customer #3: 1 MW
- Industrial/commercial customer #4: 2 MW
- Industrial/commercial customer #5: 1.2 MW

Entegrus forecasted housing loads based on municipal meetings and municipal population forecasts, pending residential applications, and meetings with building developers. Municipal input included over 6,000 new residential units in the Municipality of Strathroy-Caradoc over 2021-2046, and over 15,000 new residential units in the City of St. Thomas over 2021-2051.

As discussed in Section 3.1.4, Entegrus used historical EV registration data from the Ontario Ministry of Transportation for their service territory to estimate the existing number of EVs in its service territory. For its low growth scenario, Entegrus assumed that any further EV growth was already captured in its forecasted residential and IC&I load growth. For its reference forecast, Entegrus used a trending analysis of historical EV adoption to forecast future adoption. This resulted in an adoption of 11% in 2034 (10 years into the forecast), and 28% in 2044 (20 years). For its high growth scenario, Entegrus assumed Canada's Electric Vehicle Availability Standard would be achieved in 2035. This resulted in an adoption of 27% in 2034 and 70% in 2044.

Entegrus used a similar approach to forecast heat pump adoption as it did with EV adoption. For its low growth scenario, Entegrus assumed that any further growth in electric heating demand was already captured in its forecasted residential and IC&I load growth. For its reference forecast, it used a trending analysis based on provincial heat pump adoption obtained from Statistics Canada. This resulted in an adoption of 12% in 2034, and 17% in 2044. For its high growth scenario, Entegrus assumed a mandate similar to Canada's Electric Vehicle Availability Standard would be implemented for heating, resulting in 100% of new residential heating systems using heat pumps by 2035. This resulted in an adoption of 57% in 2034, and 99% in 2044.

3.5 ERTH Power Corporation

ERTH Power Corporation ("ERTH") is an LDC supplying electrical demand within the Town of Ingersoll, the Town of Aylmer, the Township of Norwich within Oxford County, the community of Belmont within the Municipality of Central Elgin, the community of Thamesford within the Township of Zorra, the community of Beachville within the Township of South-West Oxford, the community of Embro within the Township of Zorra, and the community of Port Stanley within Elgin County. ERTH's demand is supplied in part from the following stations: Aylmer TS, Buchanan TS, Edgeware TS, Ingersoll TS, and Tillsonburg TS. For a map of THI's service territory, please see **Figure 2** at the start of Section 3.

3.5.1 Forecast Methodology and Assumptions

ERTH considered all five of the common drivers in its forecast, and used econometric forecasting to produce its forecast. Demand growth is primarily driven by EV load growth, followed by residential load growth associated with new housing.

ERTH included firm requests in its forecast, with the largest requests listed below. To forecast IC&I demand growth, ERTH used historical growth rates of IC&I demand growth (highest, average, and lowest) and made adjustments based on feedback from the municipalities it serves, including the Oxford County 2024 Comprehensive Review. Included in this input is 120 acres of industrial land development and approx. 37 acres of commercial land development over the medium to long term in the Town of Ingersoll.

- Industrial customer #1: 4 MW

- Industrial customer #2: 3 MW
- Industrial customer #3: 5 MW
- Industrial customer #4: 2 MW

To forecast housing loads, ERTH used historical annual new residential connections (highest, average, and lowest) and made adjustments based on feedback from the municipalities it serves, including the Oxford County 2024 Comprehensive Review. This feedback includes over 500 new residential units in the near term in the Town of Aylmer, and over 2,200 new residential units by the end of the forecast period (20 years) throughout ERTH's service area.

As discussed in Section 3.1.4, ERTH used historical EV registration data from the Ontario Ministry of Transportation for their service territory to estimate the existing number of EVs in its service territory, and assumed the following EV adoptions for the end of the forecast period (2044): 50% for its low growth scenario, 80% for its reference forecast, and 100% for its high growth scenario. ERTH then used a linear interpolation between these starting and ending points to forecast EV adoption throughout the forecast period.

Due to its relatively small service area and even smaller quantity of heat pump users, ERTH was unable to directly forecast demand from potential growth in electrical heating. As a result, ERTH adjusted its electric heating demand so that the share of electric heating growth compared to total demand growth in its service area matched the average ratio from the LDCs that directly forecasted electric heating demand.[17] This was done under the assumption that the growth in electric heating demand within ERTH's service area should be similar to the average growth within the overall London Area.

3.6 Tillsonburg Hydro Inc.

Tillsonburg Hydro Inc. (THI) is the LDC supplying electrical demand within the Town of Tillsonburg. THI's demand is supplied entirely from Tillsonburg TS.

3.6.1 Forecast Methodology and Assumptions

THI considered all five of the common drivers in its forecast, and used econometric forecasting to produce its forecast. Demand growth is primarily driven by IC&I load growth, followed by residential load growth associated with new housing.

THI included firm requests in its forecast, with the largest requests listed below. To forecast IC&I demand growth, THI used historical annual new IC&I firm requests (highest, average, and lowest) and made adjustments based on feedback from the Town of Tillsonburg. Included in this input is 170 acres of industrial land development over the medium to long term, as well as up to an additional 100 acres of industrial land development over the medium term. THI's high growth scenario was largely based on the Town of Tillsonburg's municipal input, rather than limited to historical IC&I firm requests.

- Industrial customer #1: 2.0 MW

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[17] The LDCs that directly forecasted electric heating demand were: London Hydro, Hydro One Networks Inc, and Entegrus Powerlines Inc.

- Industrial customer #2: 1.4 MW
- Industrial customer #3: 2.0 MW
- Commercial customer #1: 2.5 MW
- Commercial customer #2: 2.5 MW
- Commercial customer #3: 2.5 MW
- Residential complex #1: 3.0 MW

To forecast housing loads, THI used historical annual new residential connections (highest, average, and lowest) and made adjustments based on feedback from the Town of Tillsonburg. Specifically over 2025 and 2026, THI included over 290 new residential connections. Municipal input from the Town of Tillsonburg included a strong housing forecast over the near to medium term, with households forecasted to increase by nearly 50% from 2021 to 2036. To capture this high growth, THI's high growth scenario was largely based on the Town of Tillsonburg's municipal input, rather than historical IC&I firm requests.

Compared to the other LDCs in the TWG, THI supplies a fairly small service territory, and had limited data of current EV adoption and related trends. As a result, THI forecasted annual new EVs rather than EV adoption. Depending on the scenario, this ranged from 35-145 new EVs/yr in 2034 (year 10 of the forecast), and 100-430 new EVs/yr in 2044 (year 20). Similar to other LDCs, THI assumed a non-coincident demand impact of 9.6 kW per EV, but used a higher coincidence factor in the range of 25-75%, depending on the scenario. The decision was driven by the limited number of EVs currently in the service area and in future forecasts. This creates uncertainty due to the lack of historical data and the fact that small sample sizes may not average out at the system level.

Due to its relatively small service area and even smaller quantity of heat pump users, THI was unable to directly forecast demand from potential growth in electrical heating. As a result, THI adjusted its electric heating demand so that the share of electric heating growth compared to total demand growth in its service area matched the average ratio from the LDCs that directly forecasted electric heating demand[18]. This was done under the assumption that the growth in electric heating demand within THI's service area should be similar to the average growth within the overall London Area.

4. Forecasted Distributed Generation

Distributed generation refers to any generation connected to the distribution system, rather than the transmission system. The DG forecast includes all DGs that have a contract with the IESO, up until their contract expiry date, at which point the DG is assumed to be removed from service.[19] The LDCs also provided the IESO with their existing DG connections, which were used to account for additional DGs without an IESO contract. Non-contract DGs were assumed to persist to the end of the forecast period (20 years). Finally, the LDCs provided the IESO with upcoming DG connections they are in the process of connecting, which were also included in the DG forecast.

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[18] The LDCs that directly forecasted electric heating demand were: London Hydro, Hydro One Networks Inc, and Entegrus Powerlines Inc.

[19] This assumption may be revisited during the Options Analysis component of the IRRP, if recontracting expired DG can be part of a viable solution.

For solar, wind, and biogas DGs, existing metering within the London Area Region was used to determine coincident and non-coincident capacity factors from historical data. These factors were applied to the forecasted installed capacity to produce the forecasted DG contribution to peak demand. For all other DGs with insufficient metering to develop region-specific capacity factors, the 2025 Summer and Winter Peak Capacity Contribution[20] from the IESO's 2025 Annual Planning Outlook were used instead.

5. Electricity Demand Side Management Assumptions

Electricity demand side management (eDSM) measures can reduce the electricity demand, and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and DSM programs. The assumptions used for the London Area IRRP forecast are consistent with the DSM assumptions in the IESO's 2025 Annual Planning Outlook including the 2021 – 2024 CDM Framework and anticipated long term program savings beyond that. 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 and Southwest IESO transmission zones and then allocated to the London Area region. This section describes the process and methodology used to estimate eDSM savings for the London Area region and provides more detail on how the savings for the two categories were developed.

5.1 Factors that Affect Electricity Demand

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 and Southwest transmission zones and compared with the gross peak demand forecast for each zone. From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each station in the region, as further described below.

Consistent with the gross demand forecast, 2024 was used as the base year. New peak demand savings from codes and standards were estimated from 2025 to 2044. 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. The same is done for the commercial sector. The sum of the savings associated with the two sectors are the total peak demand impact from codes and standards. It is assumed that there are no savings from codes and standards associated with the industrial sector.

5.2 Forecast Methodology and Assumptions

In addition to codes and standards, the delivery of eDSM programs reduces electricity demand. The impact of existing and planned eDSM programs were analyzed, which include the 2021 – 2024 CDM 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

[20] See Figure 2 within the Supply, Adequacy and Energy Outlook Module Data of the 2025 Annual Planning Outlook

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 and Southwest transmission zones, and finally to the stations in the region. Persistence of the peak demand savings from energy efficiency programs were considered over the forecast period.

Similar to the estimation of peak demand savings from codes and standards, annual peak demand reduction percentages from program savings were developed by sector. The sectoral percentages were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in the London Area region. They were then applied to the sectoral gross peak forecast of each station in the region.

5.3 Estimated Savings from DSM Programs

As described in the above sections, 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 analysis.

6. Forecasted Extreme Temperature

According to Section 2.4.10.1, Load Security Criteria, of the Ontario Resource and Transmission Assessment Criteria (ORTAC), "the transmission system must be planned to satisfy demand levels up to the extreme weather". As a result, extreme weather forecasts are used to assess needs in the IRRP. This section discusses how the coincident and non-coincident extreme temperature forecasts were produced from the median-weather gross demand forecast.

Historically, IRRPs have defined extreme weather as the worst value of the appropriate weather variable (temperature, humidex, or wind chill) over the last 30 years. Considering changes resulting from climate change, the IESO recognizes that the worst weather over the last 30 years may not be representative of the worst weather over the forecast period of 20 years into the future. To account for this, the IESO decided to incorporate projections of weather variables into its methodology for generating a 20-year extreme weather forecast.

At this point in time, projections of humidex and wind chill are not well established. However, an approach using temperature but informed by climate change-driven projections is a more comprehensive approach than using humidex or wind chill but uninformed by climate change. Incorporating temperature forecasts into planning products was also included on page 6 of the Minister of Energy and Mines' Integrated Energy Plan Implementation Directive for the IESO. As a result, the IESO is trialing the following new methodology for establishing a forecasted extreme temperature that is informed by temperature forecasts. The methodology consists of 5 steps, and was supported by the TWG for the London Area.

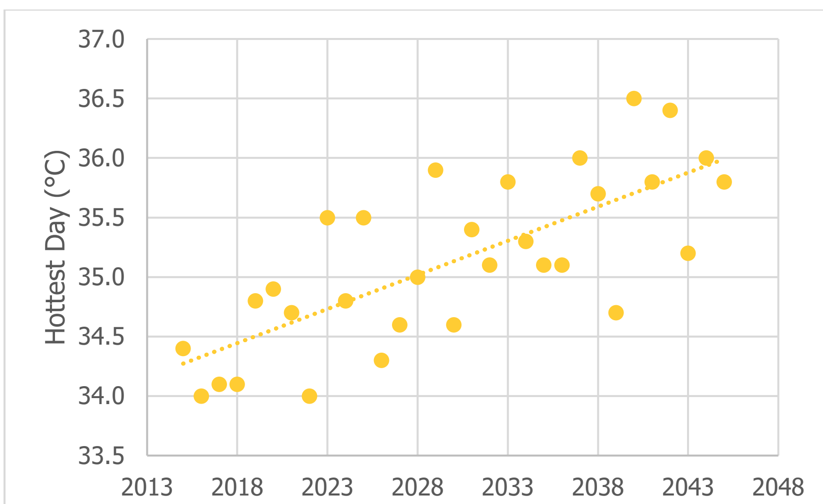
1. Determine the highest 3-day weighted average maximum temperature and the lowest 3-day weighted average minimum temperature over the past 30 years. These are the "current" extreme temperatures that would be used in the previous methodology.

2. Collect Hottest Day[21] and Coldest Day[22] downscaled CMIP6[23] climate model data for the London Area region.
3. Fit a linear relationship to the downscaled CMIP6 climate model data and take the slope of the line.
4. Apply the slope calculated in step 3 to the current extreme temperatures calculated in step 1. This produces a new linear relationship.
5. For the summer, the forecasted extreme temperature is the maximum between the linear relationship from step 4, and the current extreme temperature.
   For the winter, the forecasted extreme temperature is the minimum between the linear relationship from step 4, and the current extreme temperature.

Step 3 fits a linear relationship to the data, because as shown in **Figure 3**, climate model data includes year-to-year variations. Additionally, the Hottest Day or Coldest Day values for the starting point of the forecast generally does not match the current extreme temperatures calculated in Step 1. As a result, Step 4 applies the slope to the current extreme temperature, estimating how the extreme temperature may change over time. This is shown in **Figure 4** for the summer season.

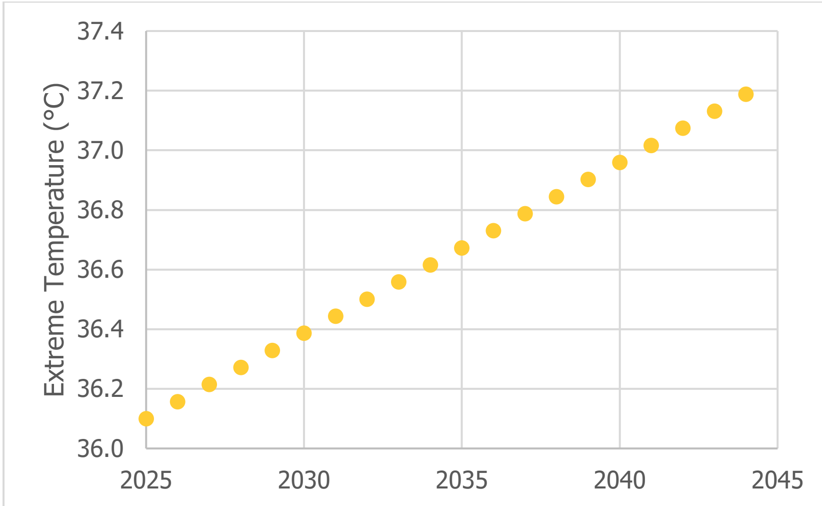
Finally, Step 5 is taken as a conservative measure since the current approach does not directly forecast extreme temperatures. While the general trend is for temperatures to rise with climate change, the 1-in-30 year coldest temperature may not appreciably change over the forecast period. Without Step 5, the winter extreme temperature may be forecasted too mild and result in lower demand than what is realistic.

Figure 3 | Hottest Day Projection



[21] Hottest Day describes the warmest daytime temperature
[22] Coldest Day describes the lowest nighttime temperature
[23] Coupled Model Intercomparison Project Phase 6 (CMIP6) global climate models, specifically the SSP2-4.5 "middle of the road" scenario is used

Figure 4 | Forecasted Extreme Temperature - Summer



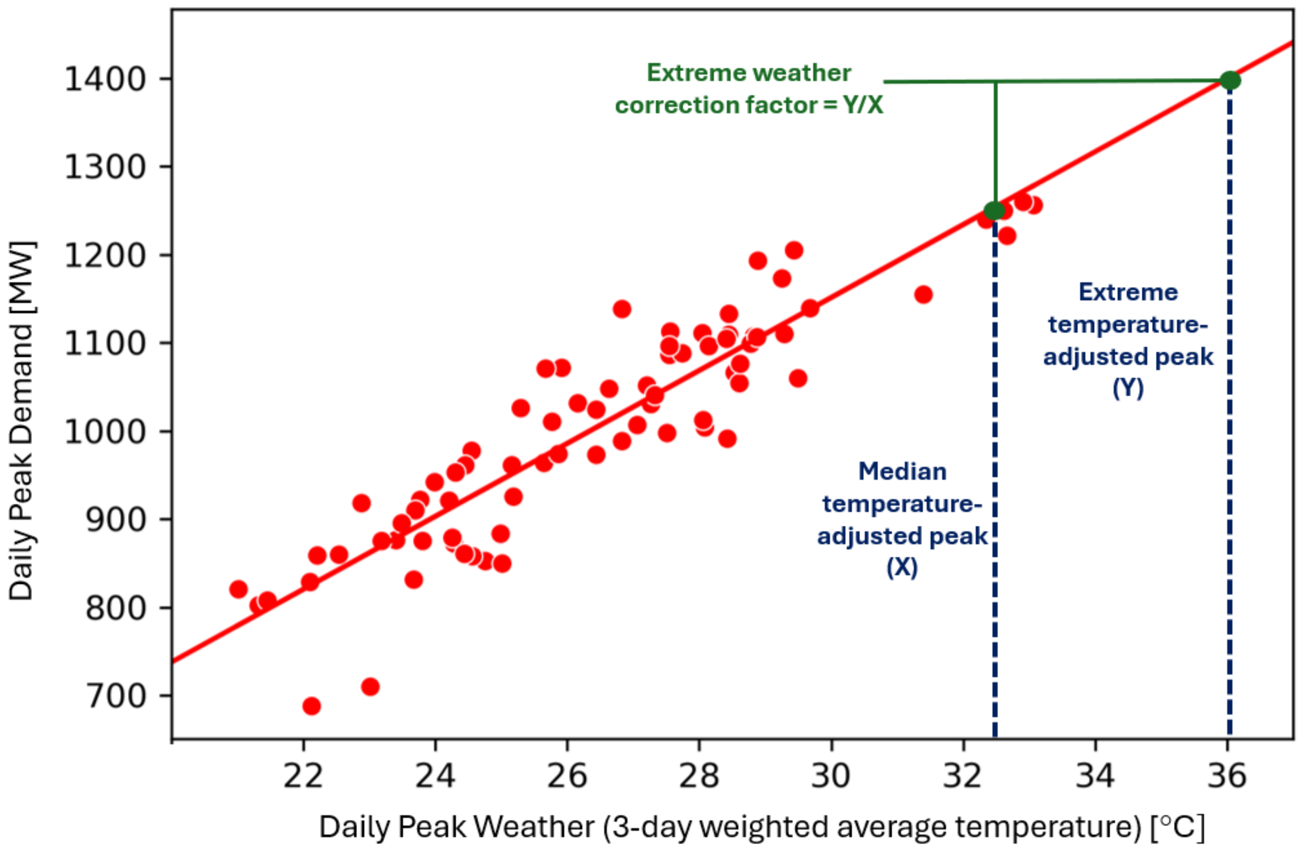
7. Final Peak Forecast by Station

Once extreme temperatures have been defined, as described in Section 6, the median-weather gross demand forecasts are converted into an extreme-weather gross coincident forecast, and an extreme-weather gross non-coincident forecast by the following processes.

7.1 Extreme-weather Gross Coincident Forecast

1. As discussed in Section 1.1, a linear regression is performed for the regional daily peak demand against the 3-day weighted average of the appropriate temperature (maximum or minimum) for each historical year and season.
2. As illustrated in **Figure 5**, the fitted line is evaluated at the extreme temperature and the median temperature. The quotient of these two values is the value of the extreme-weather coincident factor for that historical year and season.
3. The average of the historical extreme-weather coincident factors is taken, and multiplied by the median-weather gross demand forecasts. This produces the extreme-weather gross coincident forecast. Note that the median-weather gross demand forecasts are coincident forecasts per the decision of the TWG.

Figure 5 | Method for Determining Extreme-Weather Factor (Illustrative)



7.2 Extreme-weather Gross Non-coincident Forecast

This process is conceptually similar to that in the previous subsection 7.1, but with the approach taken applied to each station individually.

1. As discussed in Section 1.1, a linear regression is performed for the station[24] daily peak demand against the 3-day weighted average of the appropriate temperature (maximum or minimum) for each historical year and season.
2. The fitted line is evaluated at the extreme temperature, and then divided by the median-weather coincident peak demand of the station for the historical year and season.[25] The result is the value of the extreme-weather non-coincident factor for that historical year and season.
3. The average of the historical extreme-weather non-coincident factors is taken, and multiplied by the median-weather gross demand forecasts. This produces the extreme-weather gross non-coincident forecast. Note that the median-weather gross demand forecasts are coincident forecasts per the decision of the TWG.

[24] Note, the regression is performed for each Dual-Element Spot Network (DESN) if there are multiple DESNs within the station. Within the London Area Region, this applies only to Talbot TS.

[25] This value was calculated to produce the starting point for the station, discussed in Section 1.

7.3 Final Peak Forecast

The final peak demand forecasts were produced by taking the extreme-weather gross demand forecasts and applying the forecasted DG and the eDSM assumptions. eDSM savings are assumed to be the same for both coincident and non-coincident forecasts.