2026 Annual Planning Outlook

Demand Forecast Methodology

March 2026

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Powering Tomorrow.

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1. Introduction

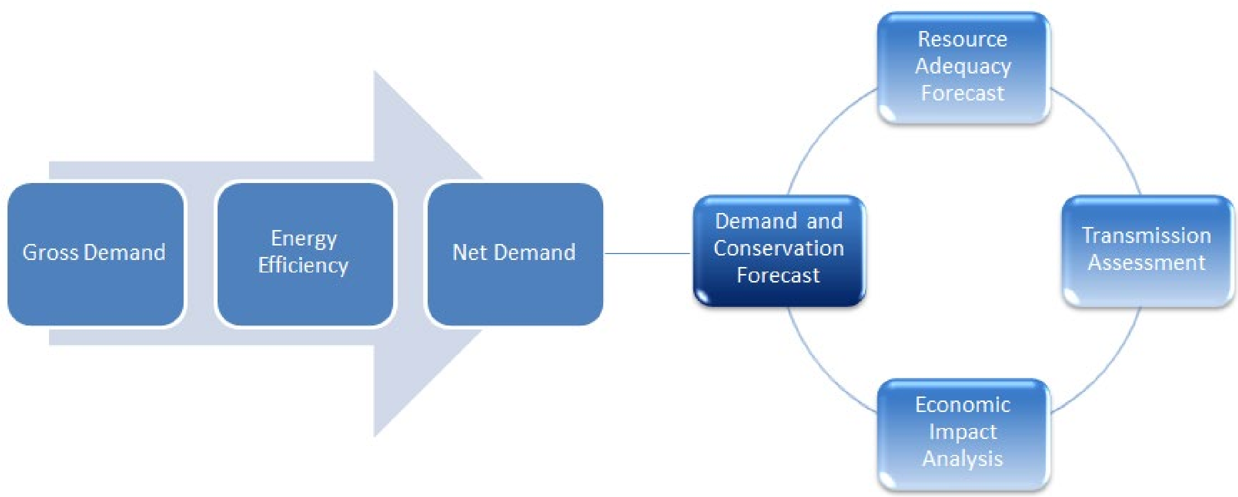
The Independent Electricity System Operator (IESO) produces Annual Planning Outlooks (APOs) for the purpose of informing stakeholders about the state of Ontario's electricity system and any necessary investment over the course of the outlook period. The demand for electricity, together with the supply outlook, establishes the context for resource adequacy and transmission security assessments, as the demand forecast determines the amount of electricity that must be served.

The APO long-term demand forecast is produced at an hourly and zonal resolution and at the net-level, generator-level demand, under a normal weather scenario. The Forecast is based primarily on a sector/sub-sector/zonal/end-use/efficiency level/fuel-type/annual and an 8,760 hourly load profile model, with additional adjustments for sectors such as agriculture, transportation, other sources of demand, demand side management programs and regulations, the Industrial Conservation Initiative (ICI), conservation, demand response programs and embedded generation. The Forecast is calibrated with historical actual demand data and aligned with the IESO's regional electricity planning activities. The document covers the methodology for development of the demand forecast.

2. Role of the Demand Forecast within the Bulk System Planning Process and the Annual Planning Outlook

The demand for electricity establishes the context for integrated planning as it determines the amount of electricity that must be served. The IESO updates the demand forecast to provide context for updated integrated plans, demand-side management program planning and supply procurement decisions. Electricity requirements are impacted by many factors, including consumer choice of energy form, technology, equipment purchasing decisions, behavior, demographics, population, the economy, energy prices, demand-side management and government policy. The IESO monitors and interprets these and other factors on an ongoing basis to develop outlooks against which integrated planning can take place. The first step in the development of the APO is to determine a long-term demand forecast.

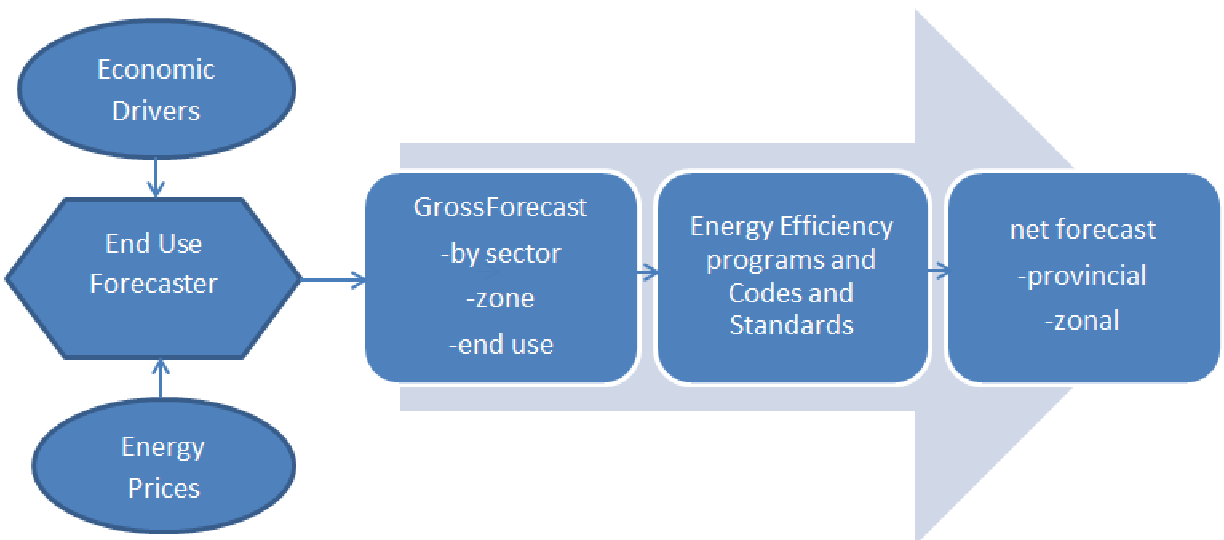
Figure 1: How the Demand Forecast Fits into Bulk System Planning



3. Demand Forecasting Process

An overview of the process used to develop the demand forecast is provided in Figure 2.

Figure 2: Demand Forecasting Process



1. **Annual Gross Energy Demand Forecast**: The production of the IESO's planning forecast begins with the estimation of energy demand at the annual, zonal, sectoral, segment, end-use, efficiency, gross and end-user levels. Demographic and economic drivers are considered in the development of the annual gross energy demand forecast, including changes in household counts and building types, commercial floor space, industrial output and energy prices. Energy demand estimates are computed with the IESO's *End-Use Forecaster model* (EUF). As a final step in this process, the IESO applies transmission and distribution line losses to convert these energy values from the end-user level to the generator level.
2. **Hourly Gross Energy Demand Forecast**: Once completed, the zonal, sectoral, segment, end-use, efficiency, gross and generator level annual energy demand data are transformed from annual values to hourly values through the application of end-use level hourly load shape profiles and then aggregated to the zonal hourly gross-level energy demand forecast.
3. **Hourly Net Energy Demand Forecast**: The hourly gross energy demand forecast is then converted to the hourly net energy demand forecast by the following adjustments:

   Demand-Side Management Programs and Regulations: Projected policy and regulation induced demand-side management savings (i.e., savings from energy-efficiency incentive programs, appliance and products standards, and commercial building codes) are identified at hourly resolution and subtracted from the hourly gross energy demand forecast.

Once completed, the zonal hourly net demand forecast establishes the amount of electricity that will need to be served and forms the starting point for resource adequacy, reliability and transmission security assessments and integrated planning analysis.

3.1 Annual Gross Energy Demand Forecast

3.1.1 End-Use Forecasting Model

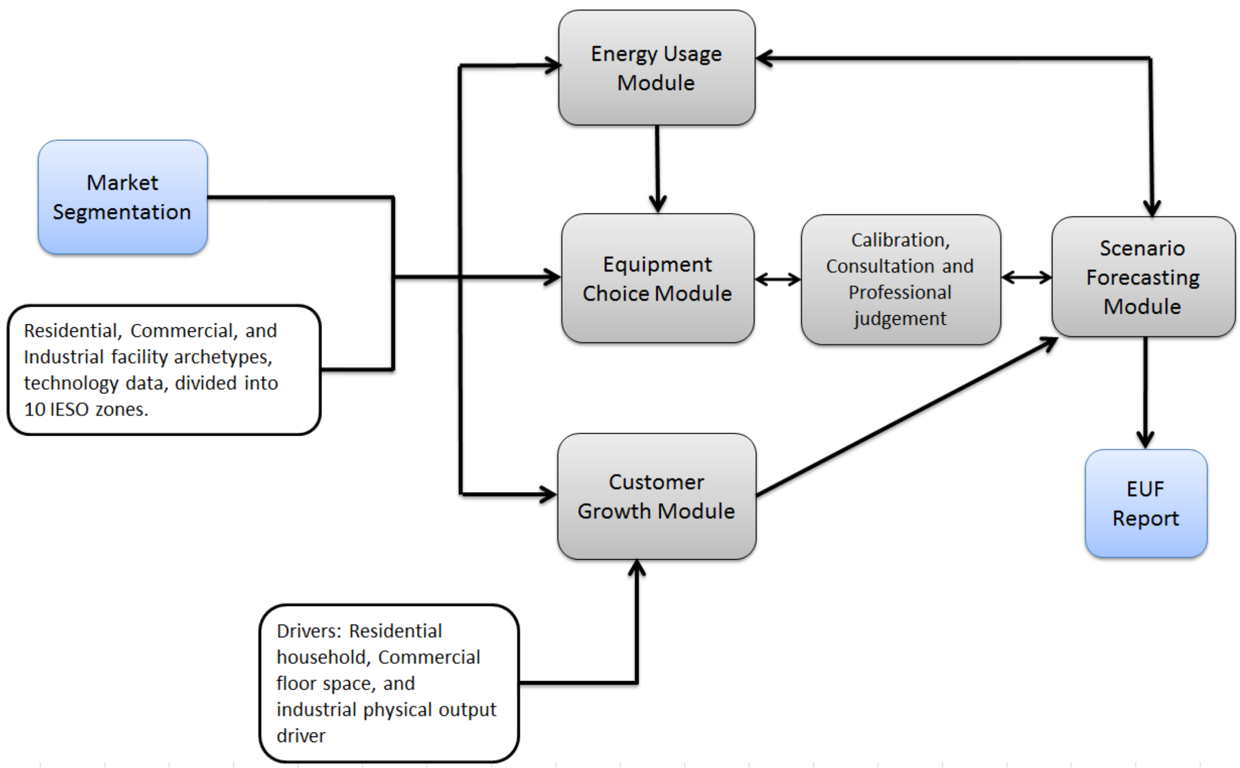
The IESO's demand forecast is developed on an end-use level basis. An end-use forecasting approach was chosen for a number of reasons, including several needs:

1. Capture structural changes in the economy, including the growth and decline of specific zones, home types, businesses or industries, and change in the relative strength of sectors.
2. Address the impact on demand of the penetration of new electricity using technologies.
3. Ensure linkages between demand-side management savings estimates and underlying assumptions of the demand forecast.
4. Specifically address the impact on peak demand of the growth of different end-uses.
5. Allow updates to the codes and standards.

The EUF is built at the IESO's transmission system electrical zonal level with all ten zones aggregating up to Ontario's provincial total. The EUF is an end-use model that tracks equipment and building stocks over time and simulates technology acquisition in the economy. The residential, commercial/institutional and industrial sectors are each analyzed separately and independently.

A schematic of the EUF is shown in Figure 3.

Figure 3: EUF Modules and Structure



3.1.2 EUF Modules

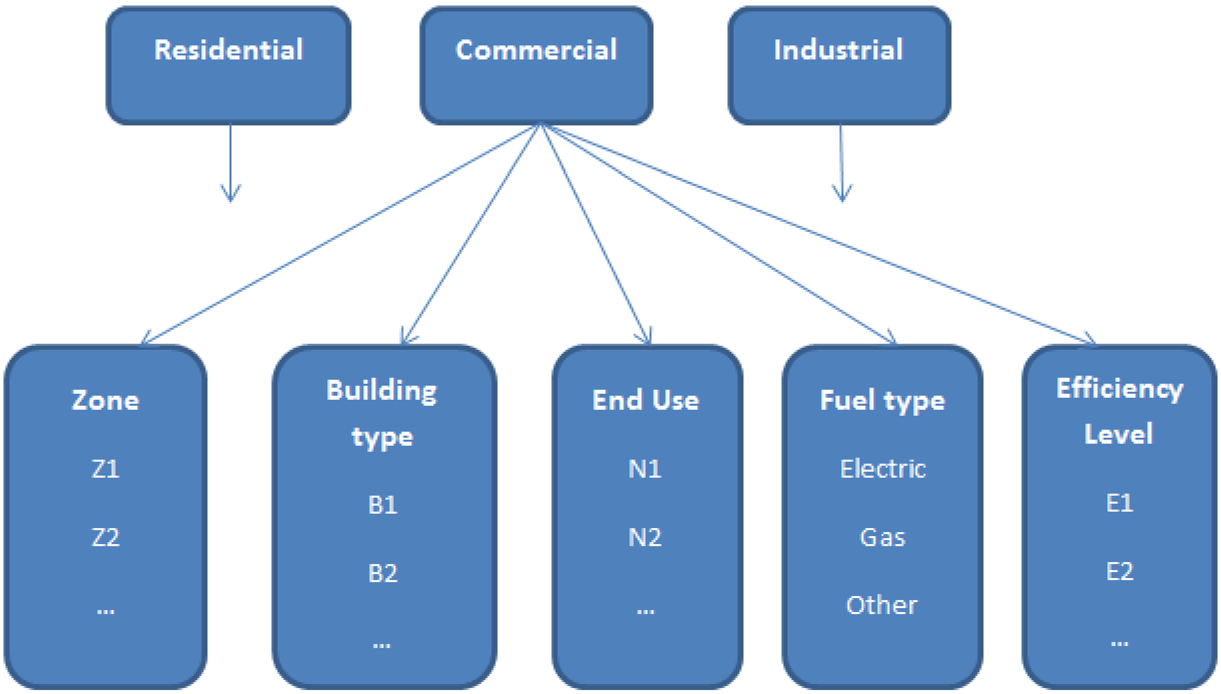
Several primary modules form the heart of the EUF analytical framework. Figure 3 also depicts the relationship between these modules.

1. Market Segmentation Module
2. Energy Usage Module
3. Equipment Choice Module
4. Customer Growth Module
5. Scenario Forecasting Module

3.1.2.1 EUF Market Segmentation Module

The *EUF Market Segmentation Module* governs the development of customized market segmentation designs and the population of the model with the necessary data. A third-party consultant supplies the majority of the data characterizing the end-uses as they apply to Ontario and its zones. The data includes building characteristics, equipment saturations, fuel shares, end-use equipment efficiency shares, replacement technology, relative efficiencies and capital costs. The IESO updates the end-use information when updates are available. The market segmentation of the model, shown in Figure 4, contains sectors, zones, building types, end-uses, fuel types and efficiency levels.

Figure 4: EUF Market Segmentation Data Category



3.1.2.2 EUF Energy Usage Module

The *EUF Energy Usage Module* tracks equipment utilization given the stock of equipment, building characteristics, and customer behavior at any moment in time over the forecast horizon. For example, single-family homes may have a discrete set of central air conditioner efficiency choices, with each efficiency level having an associated electric consumption for each year. That consumption can vary in the short run as customers modify behavior that results in changes to equipment utilization without changing the equipment itself. Factors that can affect consumption in the short run include weather, non-weather seasonal factors, building and customer characteristics, energy prices, disposable income, and other user-specified attributes. These relationships are specified in the EUF *Energy Usage Module* by combining:

1. a forecast of consumption factors or drivers (independent or exogenous variables); with
2. a set of coefficients associated with each exogenous variable.

3.1.2.3 EUF Customer Growth Module

The *EUF Customer Growth Module* tracks the number of customers (facilities) within each vintage, geographic zone, and dwelling type or sub-sector from the market characterization. Customer growth varies over time through a range of factors, including forecasts of population (typically applicable to the residential sector) and square footage of different building types (typically applicable to the commercial sector). As with the *EUF Energy Usage Module*, these relationships are specified in the *EUF Customer Growth Module* by combining:

1. a forecast of customer growth factors or drivers (i.e., independent or exogenous variables); with
2. a set of coefficients associated with each exogenous variable.

The main drivers used in *EUF Customer Growth Module*, including residential households, commercial floor space and industrial physical drivers/activities, are provided by either third-party consultants or IESO internal analyses.

3.1.2.4 EUF Equipment Choice Module

Equipment stock changes in the EUF occur in response to new driver growth, as well as to end-of-life retirement and replacement of equipment. Increasing saturation and utilization is also considered (e.g., increasing or decreasing the number of computers per household). Equipment acquisition choices are governed by choice equations that consider energy operating costs, as well as capital costs. Different technologies are represented by five efficiency choice levels for each end-use. Recognizing that price and cost savings are not the only factors that determine consumer action, the choice equation is, therefore, a weighting of financial and non-financial factors.

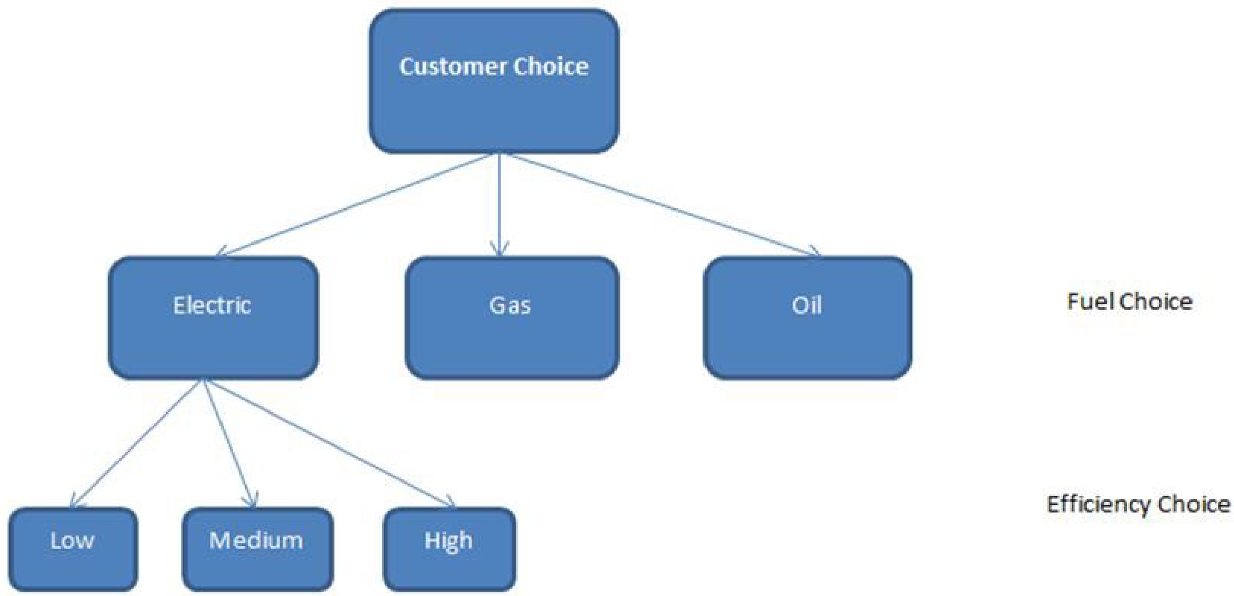
The *EUF Equipment Choice Module* analyzes customer choice decisions among competitors and product options. For example, customers choose their end-use equipment based on fuel types and efficiency levels. Purchase decisions are represented by a nested structure of provider (fuel choices) and product (efficiency choices) choices.

Choice equations are calibrated against base year new stock acquisition decisions across technology levels. For end-uses with a fuel choice (e.g., domestic water heating), purchase decisions are represented by nested fuel and efficiency choices.

Short-term behavioral response to price that reflects changes in equipment utilization without changing the equipment itself is captured through the use of behavioral price elasticity. The range of elasticity is -0.25 to -0.1 and captures behaviors, such as adjusting thermostat settings for lower Heating, Ventilation and Air Conditioning (HVAC) utilization and turning off lights and computer monitors when not required.

The hierarchy of *EUF Equipment Choice Module* is shown in Figure 5.

Figure 5: EUF Customer Choice Module Hierarchy



3.1.2.5 Scenario Forecasting Module

The *EUF Scenario Forecasting Module* combines the outputs from the EUF Energy Usage Module, EUF Equipment Choice Module and EUF Customer Growth Module. The EUF Scenario Forecasting Module then performs additional calculations regarding the turnover of equipment at the end of its useful life to produce forecasts for energy demand.

3.1.3 Calibration, Consultation and Professional Judgement

For calibration, the IESO's zonal residential energy forecasts are compared with the annual local distribution company (LDC) yearbook published by the Ontario Energy Board (OEB), which summarizes actual energy demand by rate class. The IESO's industrial forecast is also compared with IESO transmission-connected customer electricity demand trends and market intelligence based on research and consultation with IESO power system planners, industrial conservation program account managers and others.

Energy consumption trends from Natural Resource Canada's (NRCan) Office of Energy Efficiency are also used as check points with respect to provincial end-use energy and sector and sub-sector consumption trends. Information from NRCan's Survey of Household Energy Use and sales data from the Canada Appliance Manufacturers Association are used to check the IESO's equipment forecasts.

Other sources are used to check the energy demand forecast results, including but not limited to: The American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE); the Residential Energy Consumption Survey (RECS) and Commercial Building Energy Consumption Surveys (CBECS) conducted by the U.S. Energy Information Administration; and the Residential Energy Use Survey conducted by the IESO.

The IESO undertakes extensive testing and calibration during model development and implementation.[1]

3.2 Hourly Gross Energy Demand Forecast

In the "Bottom Up" method, individual sectoral, and segmental annual gross energy demand forecasts determined in the process described in the previous section are multiplied by the corresponding end-use level hourly load profiles then aggregated to create residential, commercial and industrial sector level zonal hourly gross energy demand forecasts which are in turn aggregated to form the Ontario provincial residential, commercial and industrial sectors zonal hourly gross energy demand forecasts. The advantage of this approach is that it provides detailed results that can assist with activities such as demand-side management planning and sensitivity analysis. The IESO has compared the result from the "Bottom Up" method to the available system level zonal hourly demand data to ensure that it represents a reasonable depiction of the Ontario demand profile under normal conditions.

[1] Over time the data that supports the demand forecast needs to be updated. Some of this data is updated by internal systems as it becomes available, while other inputs are procured through third-party resources and primary research. As technology and consumer behaviour evolves, end-use and other profiles require a refresh.

3.3 Hourly Net Energy Demand Forecast

In this process, demand-side management is deducted from the hourly gross energy demand forecast and results in the hourly net energy demand forecast.

3.3.1 Demand-Side Management

Demand-side management is the reduction of electricity use achieved primarily through two distinct methods: 1) resource acquisition through energy efficiency initiative frameworks; and 2) market transformation through building code and equipment standard regulations. These demand-side management savings, both persisting savings from historical activity and forecasted savings from future program delivery, would not otherwise occur in the absence of policy are deducted from the bottom-up gross energy demand forecast.

For further details on how the demand-side management forecast is derived, see Section 5.5.

3.3.2 Industrial Conservation Initiative

A final adjustment that is applied to result in the hourly net energy demand forecast is the incorporation of the forecasted impacts from the Industrial Conservation Initiative, which enables program participants to reduce their Global Adjustment charge obligations by reducing their respective individual contributions to the actual top five daily system peaks during the respective ICI season, thus benefiting the electricity system in a capacity requirement basis.

For further details on how the ICI forecast is derived, see Section 5.6.

3.4 Embedded Generation

Embedded generators are not registered participants in the IESO Administered Market and are typically connected to the distribution system; as such, these generators represent the variance between net-level demand and grid-level demand. Grid-level demand is the level of energy supplied by market participant generators, while net-level demand is the level of energy supplied by both market participant and non-market participant generators and is the level that is consistent with subsequent resource adequacy and transmission security assessments. Embedded generation is categorized as either fueled by solar, wind, hydro, bio-fuel or combined heat & power. Embedded generator output is based on a database of known generators and their respective characteristics and assumed hourly production profiles. Embedded generation is considered in the demand forecast in the formation of the base year and the grid-level demand forecast, which are discussed in later sections.

3.5 Delta Process

Two different processes are used to produce the final, calibrated, total Ontario provincial system zonal hourly net energy demand forecast for the outlook period. The first, the "Bottom Up" aggregation process has been described in the preceding Sections 3.1 – 3.3. The second, the "Delta" process, uses a base year of demand data on which each subsequent year in the "Bottom Up" demand forecast is applied, or added to. The base year forms the foundation of the Forecast as it is used as the starting point within the succeeding demand forecasting tools.

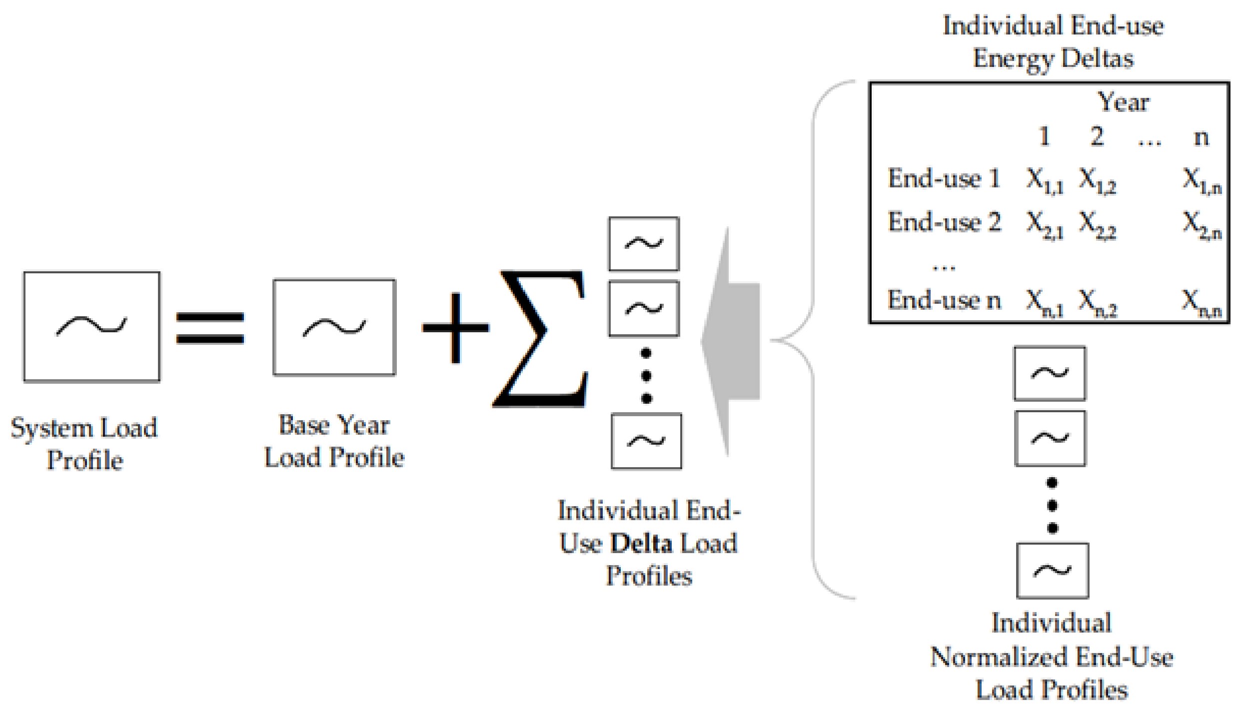
In the "Delta" process, the Ontario provincial system zonal hourly demand profile for a given base year is identified and used as a basis for the future energy demand forecast for the entire outlook period. The change in electricity use associated with a particular end-use over time is mapped to the corresponding end-use load shape, which is then after aggregation is added to or subtracted from the overall Ontario system profile.

If more electricity is to be used by an end-use over time, this constitutes an increment to the system profile. If less electricity is to be used by an end-use over time, this constitutes a decrement to the system profile.

Using a measured system demand profile as a base and adding only increments and decrements produces better alignment between the modeled and actual system profiles.

Schematics of the Delta process is shown in Figure 6.

Figure 6: Converting Annual Energy to Hourly Peak



3.5.1 Grid-Level Demand Base Year

In the 2026 APO demand forecast, a forecasted reference year 2026 zonal hourly grid demand forecast under normal weather conditions was generated for the *Delta Process* base year using simulations of energy demand incorporating weather sensitive demand and historical actual weather data developed via a linear regression model.

The base year was generated to present normal monthly peak demand, monthly minimum demand and total energy demand, by varying weather inputs. In this case, normal represents the concept that the monthly peak, minimum and total energy demand values have a 50/50, or equal probability of being higher or lower due to weather variability with all other inputs being constant. The base year output of the demand simulation weather model was produced at the grid-level of demand, thus allowing for it to be calibrated to available actual historical demand data.

3.5.1.1 Demand Simulation Weather Model Methodology for the Base Year

The *demand simulation weather model methodology* is utilized to generate the desirable properties of the base year which include capturing underlying trends and the totality of recent weather history instead of being tied to the vagaries in demand and weather of one historical year. The demand simulation weather model methodology uses a consistent set of economic, demographic and other inputs to create a forecast for the base year. Holding these inputs fixed, weather for each of the latest available past 31 years (1993-2023) is run through the demand simulation weather model to calculate the resulting hourly electricity demand. Each year is run through the model again shifting the weather backward or ahead by a day. This allows for the interaction of the weather and calendar variables. In total, the weather is shifted +/- 7 days. This results in 465 hourly demand forecasts.

From this resulting dataset the base year is produced. For each month, the simulation that gave the monthly peak demand, monthly minimum demand, and total energy demand closest to the median values of all simulations was selected, with equal consideration given to each metric. Once the simulations for all 12 months have been chosen, the hourly profiles for each month are then joined together to make up the demand profile for the entire base year.

Additional detail regarding the *demand simulation weather model methodology* can be found in the IESO's Planning and Forecasting Methodology Changes Engagement Update on September 23, 2021.

3.5.2 Net Level Demand Base Year

To align with the "*Bottom Up*" hourly net energy demand forecast the *grid-level demand base year* is converted to the *net-level demand base year*, by adding the *embedded generation output forecast*, described in Section 5.9, to each hour in the base year (2025).

3.6 Hourly Grid Energy Demand Forecast

The final product of the demand forecast is the hourly net energy demand forecast, on which resource adequacy and transmission security assessments are conducted, and is published as part of the APO.

In addition, since the 2021 APO, an hourly grid energy demand forecast in which the hourly embedded generation output forecast is subtracted from the hourly net energy demand for each hour in the outlook period is now included in the APO supporting data. This additional product of the demand forecast is being provided as a result of stakeholder engagement feedback from previous APOs and provides alignment with other IESO reporting and data including the demand forecast included in the quarterly Reliability Outlook.

4. Demand Forecast Scenarios

For the first time since the 2021 APO, the IESO's 2026 APO will include multiple demand scenarios, as per the Ontario Minister of Energy and Mine's Directive to the Independent Electricity System Operator on June 11, 2025 regarding Integrated Energy Plan Implementation. The Directive indicates that, for the purposes of planning for growth and electrification, the IESO shall incorporate in the APO multiple modelled electricity demand scenarios, including:

1) **Reference Scenario** which reflects current trends and policies in electrification, transportation, space heating, industry and other areas that impact electricity;
2) **High-Demand Scenario** that reflects a reasonable incremental increase in foregoing trends; and a
3) **Low-Demand Scenario** that reflects a reasonable incremental decrease in foregoing trends;

with appropriate and substantiated assumptions associated with these scenarios.

For the 2026 APO, distinct assumptions have been assessed for each of the three scenarios in terms of future projections in general outlook, investor confidence, trade environment, population levels, economic trends, climate, greenhouse gas emission pricing, fuel rates, building electrification policies, transportation electrification, hydrogen economy, conservation, agriculture sector, commercial data centre sub-sector, industrial mineral extraction and processing sub-sector, as well as others.

5. Drivers Used in the Demand Forecast

Residential household count is the main driver used in the residential sector forecast. Household counts have a direct relationship with electricity consumption, as end-uses are measured using households as the unit. The household count forecast is based on information provided by a third-party consultant.

Commercial floor space is the main driver used in the commercial sector forecasts. Similar to household counts in the residential sector, commercial floor space has a direct relationship with electricity consumption. The commercial floor space forecast is provided by a third-party consultant.

The major driver for industrial sector electricity demand is industrial sector activity. The relationship between industrial sector gross domestic product (GDP) output and industrial sector electricity demand use is often weak. A first effort at producing a set of physical drivers having a stronger connection with electricity use was made for each industrial sub-sector. Research, industry news, regional planning activities, and various analyses inform the development of physical drivers.

The agricultural sector's electricity demand is heavily affected by greenhouse growth light utilization associated with vegetables, flowers and cannabis in southwestern Ontario. Data provided by LDCs and direct-connect customers was used to conduct energy and peak demand analyses. Additional electricity demand in this sector is also outlined in the reference scenario in the IESO's *Need for Bulk System Reinforcements West of London* bulk study.

Electricity and natural gas rates also play an important role in the forecast. For example, higher electricity rates lead to uptake of measures with higher energy efficiency; lower natural gas rates lead to fuel switching (from electricity fueled to natural gas fueled measures), for example, space heating, water heating and cooking, and vice versa. Electricity and natural gas rate forecast assumptions are discussed in the 2026 APO Supply, Adequacy and Energy Outlook Module.

5.1 End-Use Forecaster Market Segmentation

This section includes a list of end-uses and building type for different sectors.

5.1.1 Residential Sector

Table 1: Residential Sector End-Uses

#	Residential Sector End-Use
1	Air Conditioning – Central
2	Air Conditioning – Room
3	Baseboard Heating
4	Clothes Dryer
5	Clothes Washer
6	Computer
7	Cooking
8	Dehumidifier
9	Dishwasher
10	Domestic Hot Water
11	Elevator
12	Forced Air Central Heating
13	Freezer
14	Lighting
15	Lighting - Common Area
16	Miscellaneous
17	Other Consumer Electronics
18	Refrigerator
19	Set Top Box
20	Space Heating - Room
21	Swimming Pool Pump
22	Television
23	Ventilation and Circulation

Table 2: Residential Sector Building Types

#	Residential Sector Building Type
1	Multi-Residential High Rise
2	Multi-Residential Low Rise
3	Other Residential Building
4	Row House
5	Single Family

5.1.2 Commercial Sector

Table 3: Commercial Sector End-Uses

#	Commercial Sector End-Use
1	Commercial Electric Space Heating
2	Computer Equipment
3	Cooking
4	Cooling Chiller
5	Cooling - Direct Expansion
6	Domestic Hot Water
7	Elevator
8	Heating, Ventilation, Air Conditioning - Fans and Pumps
9	Lighting - Exterior
10	Lighting - General
11	Lighting - High Bay
12	Lighting - Interior Architectural
13	Miscellaneous Equipment
14	Other Plug Load
15	Refrigeration

Table 4: Commercial Sector Business Types

#	Commercial Sector Business Type
1	Food Retail
2	Hospital
3	Large Hotel
4	Large Non-Food Retail
5	Large Office
6	Nursing Home
7	Other Commercial Building
8	Other Hotel, Motel
9	Other Non-Food Retail
10	Other Office
11	Restaurant
12	School
13	University and College
14	Warehouse Wholesale

5.1.3 Industrial Sector

Table 5: Industrial Sector End-Uses

#	Industrial Sector End-Use
1	Compressed Air
2	Electro-Chemical
3	Heating, Ventilation, Air-Conditioning
4	Lighting
5	Motors - Fans and Blowers
6	Motors - Other
7	Motors - Pumps
8	Other
9	Process Cooling
10	Process Heating
11	Process Specific

Table 6: Industrial Sector Sub-Sectors

#	Industrial Sector Sub-Sector
1	Chemical Manufacturing
2	Fabricated Metals
3	Food and Beverage
4	Mining
5	Miscellaneous Industrial
6	Non-Metallic Minerals
7	Paper Manufacturing
8	Petroleum Refineries
9	Plastic and Rubber Manufacturing
10	Primary Metals
11	Transportation and Machinery
12	Wood Products

5.2 Agricultural Sector

Historically agriculture has been a sub-sector of the industrial sector, but with the emergence of significant growth in greenhouses, producing fruits, vegetables, flowers and cannabis particularly in the West of London area, and with a distinct combination of end-uses, including lighting, space heating and ventilation, and output specific seasonality profiles, agriculture has been allocated a status as a distinct sector.

The IESO's West of London area greenhouse electricity demand forecast has been informed by multiple sources including: 1) information received from local distribution companies in the area, mainly Hydro One Distribution, including customers who have requested or inquired about connections as well as projections based on available natural gas supply capability from Enbridge Gas' Chatham pipeline expansion; 2) information received from IESO connection applicants or inquiries; and 3) historical acreage expansion rates for vegetable greenhouse growers in the area obtained from the Ontario Greenhouse Vegetable Growers Association. Further supporting segmentation, seasonality, hourly load profile and other information, data and projections have been sourced from the Regional Electricity Planning - Windsor-Essex, and the findings of the Southwest Ontario Bulk Planning.

Three main pockets of greenhouse demand growth have been identified consisting of: 1) Kingsville-Leamington; 2) Chatham-Kent, specifically the community of Dresden; and 3) Lambton-Sarnia. In each pocket, a demand forecast has been developed and informed by existing greenhouse loads, facilities for which IESO System Impact Assessment requests have been received, and with growth rates aligned with connection customers. Further incremental demand is forecasted once enabled by required transmission infrastructure implementation in 2026.

Seasonal and hourly demand profiles are based on greenhouse crop output product segmentation and greenhouse end-use saturations in which the IESO obtains updates on a regular basis, from its market research and consultant findings.

Existing agricultural sector demand from sources other than greenhouses in the West IESO zone, as well as the rest of the province in general, has been maintained and updated, with standard modelling processes similar to the industrial sector, as appropriate.

5.3 Transportation

5.3.1 Electric Vehicles

The demand forecast of transportation electrification consists of the proliferation of electric vehicle (EV) charging demand and rail transit electrification projects. EVs are among the most important components of the drive towards decarbonization and electrification. The quantity of EVs on the road in Ontario and the associated charging electricity demand are fast growing and projected to increase significantly over the next decades. The EV demand forecast is done outside of the End-Use Forecaster model. The annual energy demand, peak impact, and hourly demand forecast over the planning horizon are estimated and fed into subsequent power system planning analyses.

EV is a unique electricity end-use with its own characteristics. Many factors can affect EV charging demand, including the number of EVs, vehicle size and type, driving distance and pattern, battery capacity, fuel efficiency, and charger type. It is also a flexible end use in terms of time and location. EV demand is relatively new, fast growing, and evolving. Therefore, the demand forecast for EV charging has a much higher uncertainty than many other end-uses. The IESO analyzes EV demand with available information, such as government policies and targets, market trends, studies, and other organizations' forecast, as well as assumptions and professional judgement. Managed EV charging is assumed to avoid adding significant burden to electricity infrastructure. The IESO will continue updating its forecast when new information is available.

Three scenarios of EV forecast are developed for this APO, starting with adoption assumptions. A stock and flow model is then utilized to convert EV adoption to EV population. Together with factors such as fuel efficiency and driving distance, electricity charging demands are estimated. Light duty EV is analyzed first, which represents majority of EV population. Medium and heavy-duty vehicles (weighing more than 4,546 kilograms) represent a very small portion of total vehicles in the province. Their electrification opportunities are very different from light duty vehicles.

The reference scenario reflects continued considerable growth in EV adoption but below the previous federal Zero-Emission Vehicle (ZEV) mandate, which was replaced in February 2026[2]. Achievement of the 100 per cent light duty EV sales targets is assumed to be delayed to 2043. Light-duty EVs in Ontario are projected to increase from nearly 300 thousand in 2025 to 10.6 million in 2050, with a forecasted annual EV charging demand of 34.2 terawatt-hours (TWh) by 2050.

[2] In February 2026, the federal government announced the repeal of the Electric Vehicle Availability Standard and its annual sales targets, and policy shift to vehicle emissions standards. The government has stated that it expects the emissions standards to result in EVs representing 75 per cent of new sales in 2035 and 90 per cent in 2040 (from 100 per cent in 2035). These changes will be fully reflected in the 2027 APO.

The high scenario assumes that provincial light duty EV adoption meets the previous federal EV sales targets in place at the time of forecast development, which required light duty sales reach 100 per cent by 2035. The light-duty EV population is projected to increase to 11.5 million in 2050 with a forecasted charging demand of 37.1 TWh.

The low scenario assumes moderate to low growth in light duty EV adoption, as informed by the EV adoption trend in recent years. The light-duty EV population is projected to increase to 6.1 million in 2050 with a forecasted charging demand of 19.6 TWh.

Currently, medium and heavy-duty vehicles combined represent less than three per cent of total vehicles in the province. The small population comes together with a wide range of unique usage patterns and requirements, some of which make electrification more challenging. For those suitable for electrification, there are competing technologies that continue to progress. High uncertainty exists around future market shares of catenary, battery-electric, hydrogen fuel cell, bio-based diesel, and other technologies in the medium and heavy-duty vehicles segment. This APO focuses on battery-powered medium and heavy-duty EVs, which draw power directly from the grid. It is assumed that they will lag light-duty EVs. Three scenarios were analyzed where reference and low scenarios are kept the same. All three scenarios assumed that 100 per cent of school buses and transit buses will be powered by batteries over the coming years. For other medium and heavy-duty vehicles, two levels of battery powered EVs are considered. Overall, the reference scenario and low scenario estimate 53 thousand battery-powered medium and heavy-duty EVs in 2050 with a forecasted annual charging demand of 3 TWh, while the high scenario estimates 90 thousand EVs with a forecasted 5.1 TWh annual charging demand in 2050.

The last step is to develop hourly charging demand for subsequent power system analyses and modelling purposes. The EV charging profile, which is a representation of when and how EVs are charged, is applied to the annual energy demand from the preceding steps to arrive at an hourly demand forecast. EVs are a flexible end-use that practically can be charged any time when not in use, which represents the majority of time. Customer preference, battery size and status, driving conditions, time-of-use electricity rates, and active EV charging load management programs are among factors affecting the charging profile. The flexibility of EV charging load inherently carries high uncertainty, presenting challenges in forecasting. At the same time, the flexibility of EVs makes it possible to manage the load such that it contributes to power system planning and operation needs. The APO adopts a managed charging profile developed in a recent study by a consultant, which assumed that a portion of EV charging demands occur outside of system peak periods.

5.3.2 New Rail Transit Projects

A few rail transit electrification projects are at various stages of planning, construction and operation in Ontario, including the GO Transit rail system, nine light rail transit projects, and three subway lines in the Greater Toronto Area. Electricity demands for these projects are high level estimates using available information from the transit agencies. Some projects continue experiencing delays while others are at the early planning stage. Therefore, both the magnitude and timing of electricity demands carry high uncertainty. These projects, when in operation, are expected to have an annual energy demand of 2.4 TWh. The same rail transit electrification demand forecast is considered under all three scenarios.

Following the finalization of the 2026 APO demand forecast, the federal government made a series of announcements confirming support to proceed with the Alto High Speed Rail project (previously VIA High Frequency Rail) and significantly accelerate planned construction timelines. With these developments, the IESO is working to incorporate the Alto project into the demand forecast for future APOs.

5.4 Other Electricity Demand

The "Other Electricity Demand" category of demand includes:

1. connection of remote communities
2. street lighting;
3. electricity generator demand; and
4. water treatment facilities.

Demand forecasting methodologies vary for each of the *Other Electricity Demand* sub-sectors and reflect study results from third-party consultants, the IESO's regional resource planning, and consultations with LDCs.

5.5 Demand-Side Management

Electricity demand-side management (eDSM) helps to meet Ontario's electricity needs. EDSM has made a significant contribution to electricity service in Ontario and has been an integral part of a reliable and sustainable electricity system in the province. New savings are forecasted separately by programs and regulations.

5.5.1 eDSM Programs

EDSM programs have been funded and/or delivered by the IESO and predecessor organizations since 2006 based on committed provincial government program framework funding policy. Demand savings from programs delivered in the past have been verified with expected finite persistence lives.

5.5.1.1 Historical Programs

Historical demand-side management program frameworks that continue to deliver savings include: 1) the 2019-2020 Interim Framework for the delivery of Energy Efficiency Programs; 2) the 2015-2020 Conservation First Framework; Industrial Accelerator Programs and their respective wind-downs; and 3) the 2021-2024 Conservation and Demand Management Framework. Electricity savings from these programs were evaluated, measured, and verified by the IESO and predecessor organizations.

5.5.1.2 Current Frameworks

On November 7, 2024, Ontario's Minister of Energy and Electrification directed the IESO to launch a new, 12-year Demand-Side Management (DSM) Framework to help meet the needs of Ontario's electricity system cost-effectively, including by focusing on capacity and electricity savings and supporting reliability. As part of the IESO's $10.9 billion, 12-year funding commitment from the Ontario government for continued and expanded demand-side management opportunities for electricity consumers across the province, the IESO is implementing the 2025-2027 three-year eDSM plan that establishes budgets and demand and energy savings targets by sector. These projected savings are included in the APO demand forecast and are the same across three scenarios.

In addition to the IESO administered programs, a few federally funded programs are in the market and are expected to achieve electricity savings in Ontario. These programs are designed to reduce emissions, target various fuel types, and are eligible for Ontario as well as other provinces and territories. The resulting electricity savings in Ontario are estimated as 0.2 TWh in 2026. Since these programs are not administered by the IESO, the savings are estimated with higher uncertainty as not all program details are currently available.

5.5.1.3 Long-term programs

Beyond the eDSM programs already in the market, it is anticipated that demand-side management efforts will continue throughout the planning horizon. New savings are expected to materialize as a result of continued delivery of demand-side management initiatives. For planning purposes, incremental annual energy savings beyond the current Framework are assumed to be a portion of gross demand excluding transportation demand (reflecting that vehicle efficiency appears to be outside the scope of the IESO's eDSM programs). On average, annual electricity savings of the current Framework represent about 0.9 per cent of the gross demand. Starting from 2028, new annual savings are estimated at 1.0 per cent of gross demand in the reference and high demand scenarios and 0.9 per cent in the low demand scenario.

5.5.2 Demand-Side Management Regulations

Demand-side management regulations savings are based on the expected improvement in building codes and specified end use equipment standards and are an effective energy efficiency tool that embeds energy savings in buildings and equipment upgrades through federal and provincial regulations and requires no incremental ratepayer investment.

5.5.2.1 Ontario Building Codes

Building code regulations (hereinafter referred to "codes") set minimum energy-efficiency requirements for new and substantially renovated buildings.

New commercial buildings or buildings undergoing major renovations are subject to provincial and federal codes. The energy-efficiency requirements in codes are often defined as a reduction factor (e.g., 25 per cent more efficient than a design conforming to Model National Energy Code for Buildings (MNECB)). Given the broad range of design and technology choices that can meet these requirements, the IESO codes analysis also uses reduction factors.

The codes analysis deals with heating, cooling, ventilation and lighting end-uses. Collectively, they represent about 60 per cent of the gross energy consumed by the commercial sector in the EUF. Each end-use has an energy use intensity (EUI) measured in energy per unit floor space kilowatt-hours per square foot (kWh/ft^2) in the base year, which is used as its baseline performance. Estimated reduction factors set the minimum codes-compliant EUI relative to this baseline.

Floor space turnover: Each end-use has a retirement rate, defined as 1/EUL (effective useful life). For example, commercial chillers have an estimated lifespan of 40 years, so the annual retirement rate is 2.5 per cent. The demand forecast for each end-use is re-modeled by breaking the annual floor space value into annual values for:

1. Existing floor space;
2. New floor space; and
3. Renovated floor space.

Existing floor space decreases at the retirement rate. Renovated floor space for a given year is equal to the total floor space that was retired in the previous year. New floor space is estimated as the annual increase in total floor space. For each year, renovated floor space is subject to EUI reduction associated with federal building standards and new floor space is assigned an EUI based on the Ontario Building Code.

Reduction Factors: The reduction factors below were developed from estimates of the effect of existing codes on electricity-consuming end-uses. Planned future improvements to codes reflect a long-term trajectory of demand side management policy with incremental improvements.

Table 7: Ontario Building Codes Regulation

#	Regulation	Effective Date	Reduction from Baseline
1	2006 C-OBC Improvements	2006	24 %
2	2012 C-OBC Improvements	2012	30 %
3	2015 C-OBC Improvements (planned)	2015	35 %
4	2020 C-OBC Improvements (planned)	2020	38 %

Renovation

#	Regulation	Effective Date	Reduction from Baseline
1	ASHRAE 90.1-1999/MNECB	2000	19 %
2	MEPS - Federal Standards	2012	22 %
3	MEPS - Federal Standards (planned)	2015	24 %
4	MEPS - Federal Standards (planned)	2020	25 %

5.5.2.2 Equipment Standards

Equipment standard regulations (hereinafter referred to "standards") mandate the minimum energy performance standards (MEPS) required of select new equipment.

A third-party consultant was engaged by the IESO in 2015 to undertake an assessment of the electricity savings resulting from changes to energy-efficiency product performance standards for residential and select commercial equipment. The savings attributed to product standards were calculated relative to a reference case of energy consumption of each product. The reference case represents the baseline against which all future savings are compared. The third-party consultant developed a demand side management savings forecasting model that includes the methodology used for the United States of America's Department of Energy rulemakings and customized the model to calculate the expected electricity savings achieved from standards for each product. The IESO estimates savings attributed to codes and standards by comparing the gross demand forecast to the forecast adjusted for the impacts of regulations.

The analysis incorporates new or updated standards that have a compliance date between Jan. 1, 2013 and Jan. 1, 2019 and also considered potential future standards beyond 2019 for each product. The IESO has reviewed each standard to ensure it is up to date.[3]

5.6 Industrial Conservation Initiative

The Industrial Conservation Initiative (ICI) is a function of Ontario Regulation 429/04 that allows for participants to determine their Global Adjustment rate for a given Adjustment period based on their Peak Demand Factor which is determined based on a customer's percentage contribution to the top five system peak day, system peak hour, in the preceding Base Period. ICI participants reducing their energy demand during these periods enables them to reduce their Global Adjustment rates. For a given Base Period, the actual system peak days are determined retroactively, and it is observed that due to this uncertainty, ICI participants typically respond to system demand conditions in greater than the five top system peak days, to mitigate the risk of not responding in the resulting top five system peak days in the Base period.

[3] Differences in the baseline demand forecast between the IESO and the third-party consultant have been addressed:

1. **Difference between natural efficiency assumptions**: The third-party consultant assumed little to no natural efficiency. Based on the assumption that people naturally choose more efficient products, the IESO's gross energy demand forecast includes the effects of naturally occurring demand management savings, but not the effects of new interventions.
2. **Difference in method to analyze each end-use**: While the third-party consultant estimated the end-use energy consumption by product class, the IESO uses a maximum of five technology energy efficiency levels to represent overall end-use energy consumption.
3. **Difference in total forecasted consumptions**: The third-party consultant forecasted energy consumption for end-uses of interest; the IESO forecasts energy consumption for the entire sector/province.

Ontario Regulation 509 was used as the reference when standards savings analysis was in development.

For the long term demand forecast, forecasted ICI responses are based on maximum single hour system level ICI response observed from the latest [ICI base period](#) available at the time of the development of the demand forecast, and is identified separately at the seasonal (summer and winter) and IESO Zonal levels. ICI responses are forecasted to change on an annual frequency based on forecasted changes to industrial sector gross annual energy demand and at the IESO Zonal level. Based on the same latest observations ICI responses are forecasted to occur on the top 15 grid-level system peak days (ICI Days). ICI Days are forecasted on a calendar year basis, each ICI Day's peak ICI response is forecasted based on the forecasted maximum annual seasonal ICI response and is adjusted corresponding to the ICI Day's system peak demand relative to the forecasted annual system peak demand. ICI Day Hourly ICI response is forecasted to 'follow' the ICI day's hourly demand and occur only on hours of peak demand levels and to be always non-negative in terms demand savings.

5.7 Demand-Side Management Demand Response Programs

5.7.1 Save on Energy Peak Perks Program

On May 25, 2023, the Ontario government launched Save on Energy Peak Perks, a program developed by the IESO in response to the Ministerial Directive dated September 29, 2022. Peak Perks is a demand response program that gives families and small businesses more ways to lower their energy bills and provides a financial incentive in exchange for lowering their energy use at peak times during the summer. Peak Perks aims to lower system demand during peak periods and allows the province to reduce electricity sector emissions, by reducing the need for electricity generation facilities that only run at times of peak demand such as natural gas.

The Peak Perks program had been added to the 2021-2024 Conservation and Demand Management Program Framework, extended in the 2025-2036 Electricity Demand Side Management Framework and is assumed to be delivered in perpetuity, consistent with the long-term demand forecast's long term conservation assumption. Peak Perk's activation criteria consists of:

1. June 1 to September 30 activation period;
2. Weekdays only;
3. Up to 10 activations per year
4. A maximum of one activation per day
5. An activation period of three contiguous hours
6. A activation day trigger of either:
    a. A forecasted grid-level peak demand greater than 22 gigawatts (GW) on or after noon;
    b. An IESO Emergency Procedure declared; or
    c. IESO's discretion.

For the purposes of the demand forecast, it is assumed that the Peak Perks program is activated on each of the top 10 June 1 – September 30 weekday grid-level peak demand days each year, centred on the system peak hour and adjacent hours, at the forecasted demand savings level in the reference year and forecasted savings changes each year based on forecasted changes in residential and small commercial sector air conditioner unit installed count and zonal response based on forecasted zonal residential and small commercial sector air conditioner annual energy demand. Adjustments factors include: 1) discounted capacity factors on an system basis as well as initial and final hours of the three hour activation period; and 2) based on program evaluation, measurement and verification findings available at the time of forecast finalization a period of program impact rebound following each program activation.

5.7.2 Save on Energy Commercial Heating Ventilation Air Conditioning Demand Response Program

As part of the IESO's 2025-2027 Electricity Demand Side Management Program Plan released January 23, 2025, a new demand response (DR) program targeting commercial sector HVAC end-uses is expected to launch in 2026.

At the time of forecast finalization, design of the Commercial HVAC DR program was in early stages; as such, program design and impacts were assumed to be similar to the Peak Perks program, targeting buildings in the commercial sector (including offices and retail) and achieving planned demand savings targets as outlined in the eDSM Program Plan. Updates to forecasted impacts in the program once the design is finalized and the program launched will be incorporated into future APO long-term demand forecasts.

5.8 Fuel Rates

The IESO's electricity demand forecast is based on forecasted annual fuel rates for: 1) electricity; 2) natural gas; and 3) other fossil fuels (heating oil/propane); for each of the a) residential; b) commercial; and c) industrial; sectors over the course of the outlook period. The inclusion of fuel rate forecasts for electricity alternatives plays an important role in the calculations of the equipment choice module highlighted in Section 3.1.2.4.

5.9 Embedded Generation

Since the 2021 APO, a grid-level energy demand forecast that incorporates the net-level energy demand forecast and an *embedded generation* output forecast for the outlook period, in addition to the base year, is included. Embedded generation is defined as an electricity generating resource that does not participate in the IESO administered wholesale market, injects into the distribution system rather than offsetting load and is generally grouped by fuel type: solar, wind, hydroelectric, biomass and natural gas. Embedded generation is considered in developing the *net-level demand base year* described in Section 3.5.2 as well as producing the hourly grid energy demand forecast described in Section 3.6.

As *embedded generators* are resources that are not market participants, it is challenging to obtain accurate data on: 1) actual resources; and 2) hourly data on actual energy production; where such resources are not contracted with the IESO. The *embedded generation* output forecast relies on the most credible data available, that is monthly energy by fuel type reported by LDCs through IESO's settlements.

Two of these fuel types are of particular interest to forecasting demand: solar and wind. The reason is twofold. First, these two fuel types are the most common type of embedded generation and account for over 2,000 megawatts (MW) of installed capacity. Secondly, the output from these two fuel types is correlated to weather in a manner similar to demand. For the solar and wind *embedded generation* output forecast and the normal weather base year forecast described in section 3.5.1, the same weather simulation models were run for both forecasts resulting in a consistent weather approach. For the remaining embedded generation fuel types, hourly output is calculated using hourly profile assumptions. The hourly profile is developed for the remaining fuel types by using available information from various sources, including: local distribution company data, IESO contracts information (capacity), and IESO settlements data (monthly energy).

For the purposes of the embedded generation forecast for the grid-level long term demand forecast, the embedded generation output forecast is based on: 1) consistent hourly profiles for the fuel type and for each year, adjusted for expected changes in available capacity and operating conditions; 2) and continued availability of existing resources until contracts with the IESO expire (which results in a declining embedded generation forecast over time).

5.10 Regional Planning Alignment

Regional planning[4] is a continual process, with electricity reliability evaluated at minimum every five years in each region with local distribution companies, transmission system providers and customers. The IESO's long-term demand forecast takes into accounts specific learnings from each assessment's latest findings in terms of forecasted demand.

Table 8: IESO Regional Planning Regions

#	Region	Sub Regions			
1	Burlington to Nanticoke	Brant	Bronte	Hamilton	
2	Chatham-Kent / Lambton / Sarnia				
3	East Lake Superior				
4	Greater Bruce / Huron	Southern Huron-Perth	Southern Huron-Perth		
5	Greater Ottawa	Ottawa			
6	Greater Toronto Area East	Pickering-Ajax-Whitby	Oshawa-Clarington		
7	Greater Toronto Area North (York)				
8	Greater Toronto Area West (Peel & Halton)	Northwest GTA	Southwest GTA		
9	Kitchener-Waterloo-Cambridge-Guelph				
10	London Area	Greater London	Alymer-Tillsonburg	Strathroy	Woodstock
11	Niagara				
12	North / East of Sudbury				
13	North of Moosonee				
14	Northwest Ontario				
15	Peterborough-Kingston				
16	Renfrew				
17	South Georgian Bay / Muskoka	Barrie / Innisfil	Parry Sound / Muskoka		
18	St. Lawrence				
19	Sudbury / Algoma				
20	Toronto				
21	Windsor-Essex				

[4] More information on the regional planning process can be found here.

5.11 IESO Electrical Zones

Table 9: IESO Electrical Zones

#	Zone
1	Bruce
2	East
3	Essa
4	Niagara
5	Northeast
6	Northwest
7	Ottawa
8	Southwest
9	Toronto
10	West

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