Load Forecast Guideline for Ontario

Guidance for the Development of Regional Planning Demand Forecasts

Regional Planning Process Advisory Group

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1. Background

The long-term expectation of peak electricity demand in a given region is key to assessing the reliability of electricity supply to the region. As such, the development of a peak demand forecast is a fundamental step in the regional planning process.

Since the Regional Planning Process was formalized by the Ontario Energy Board (OEB) in 2013, the Independent Electricity System Operator (IESO), transmitters (including Hydro One), and electricity distributors have worked together to develop regional planning demand forecasts according to the high-level process documented in the 2013 Planning Process Working Group (PPWG) Report to the Board. In February 2021, the IESO published the Regional Planning Process Review Final Report which included a recommendation that called for a streamlined and standardized process for demand forecast development in order to increase consistency and efficiency in the methodology while accommodating the uniqueness of customers across different regions. The OEB and the IESO agreed that the OEB should take the lead on implementing that recommendation and the OEB re-established its Regional Planning Process Advisory Group (RRPAG) to assist the OEB in reviewing this and other IESO recommendations, as part of its Regional Planning Process Review.[1] This Demand Forecast Guideline was adopted by the RPPAG after its initial development was completed by a subgroup of the RPPAG – the Load Forecast Subgroup.[2]

The RPPAG also considered the development of a template. However, as discussed in the RPPAG's Report to the OEB, the RPPAG concluded that development of a template should be deferred. The RPPAG therefore plans to develop a template in the future once experience is gained in using this Demand Forecast Guidance document and feedback is obtained from participants in the regional planning process following implementation.

2. Objective

The objective of this document is to provide guidance to the IESO, transmitters and electricity LDCs in the development of the demand forecasts used in the various phases of the regional planning process with a focus on the Needs Assessment (NA) and the Integrated Regional Resource Plan (IRRP).

The approaches outlined in this guidance document are meant to form a basis for the general process; however, it is recognized that variations to these approaches may exist and be warranted by local characteristics and circumstances. Where such variations are agreed to be deployed by the Technical Working Group (TWG), the TWG will provide and document the rationale, in the respective planning documents (along with the demand forecast assumptions), for the selected approach in order to enhance transparency.[3]

[1] EB-2020-0176.
[2] The Load Forecast subgroup consisted of members from the following organizations: Alectra Utilities, Association of Municipalities of Ontario, Enbridge, Hydro One, IESO, London Hydro, Pollution Probe, School Energy Coalition, Toronto Hydro. OEB staff also provided non-technical input.
[3] The TWG in each region is comprised of the IESO, lead transmitter and LDCs within the region.

Further, it is recognized that these processes will continue to evolve over time with consideration of the following: changing weather patterns due to climate change[4]; evolving end-uses due to electrification; enhanced distributed generation (DG) visibility and data availability; and, general improvements to tools and methodologies used in other demand forecast processes such as the IESO's provincial demand forecast and that of LDCs. The guidance provided within this document is meant to help guide the development of the demand forecasts to enhance clarity, consistency and transparency, but also remain flexible to future evolution.

Given how the system is evolving and will continue to do so (e.g., decarbonization, electrification, etc.), the RPPAG plans to review this guidance document at least every two years, or as required to address emerging issues.

3. Scope and Structure of the Guidance Document

This guidance document covers the processes to develop the regional planning demand forecasts for the NA and IRRP stages of the regional planning process, building off the high-level process outlined in the 2013 PPWG Report to the Board.

With respect to the demand forecast for the Regional Infrastructure Plan (RIP) stage of the regional planning process, the RIP will adopt the demand forecast developed for the IRRP except where there is a *material change* not captured within the IRRP. Where the members of the TWG in a region (i.e., IESO, Hydro One and applicable LDCs) agree a material change has occurred, the IRRP forecast will be updated for use in the RIP. The reasoning should be documented in the RIP report for transparency. Given that the IRRP phase is an 18-month process and the RIP phase begins shortly after the completion of the IRRP, it is possible a material change has occurred. For example, a material change could include (but is not limited to): an update from an LDC(s) on their forecast compared to what they submitted during the IRRP phase; a material step-change of the forecast starting point for the RIP (e.g., actual 2021 net peak demand versus the forecasted 2021 net peak demand in the IRRP demand forecast), etc.

The following key components of the NA and the IRRP forecasts are covered within this document:

Regional Planning Stage	Lead[5]	Demand Forecast Type	Key Components
Needs Assessment	Transmitter	10-year extreme-weather planning demand forecast	• Forecast Starting Point (including weather correction and concepts of regional coincidence and non-coincidence) • 10-year Gross Forecast • 10-year Planning (Net) Forecast • Sensitivities

[4] These changes could mean that historical demand patterns are less indicative of what could materialize over the planning horizon.
[5] Lead in this context is the entity that leads the respective stage of the regional planning process. All planning partners including the IESO, the transmitter and LDCs make up the Technical Working Group and play an important role within the development of the regional planning demand forecasts.

Integrated Regional Resource Plan	IESO	20-year extreme-weather planning demand forecast	• Forecast Starting Point (including weather correction and concepts of regional coincidence and non-coincidence) • 20-year Gross Forecast • 20-year Planning (Net) Forecast • Sensitivities

The sections that follow outline the guidance related to each key component of the NA and IRRP demand forecast. This report is split into two main sections: one each for the NA and IRRP. The reason for this is that the processes to develop the demand forecasts for the NA and IRRP can differ in accordance with the objectives of each of these documents, as agreed to by the RPPAG.

4. The NA and IRRP Demand Forecast Processes

The processes employed to develop the peak demand forecasts for the NA and IRRP differ in accordance with the overall objectives of these regional planning phases and their respective planning horizon. As noted in the 2013 PPWG Report to the Board, preliminary demand forecasts are required to identify significant changes in growth rates seen at the delivery points and generally at the regional level for the purposes of the NA, which is meant as a screening exercise. The 2013 Report similarly notes that more detailed demand forecasts will only be required when it is determined that regional planning and coordination is necessary, which is achieved via the IRRP and the RIP.

5. *Needs Assessment: Developing the 10-Year Planning Forecast*

For the purposes of the NA, a 10-year extreme-weather gross and net peak demand forecast is developed to assess the reliability of electricity supply over the planning horizon. This section of the guidance document outlines the process, data requirements and leads for each key component of the NA forecast.

5.1 Forecast Type

In the regional planning context, the demand at a given station at the time when the aggregate regional demand is highest is typically referred to as the "regional *coincident*" station peak, whereas the highest station demand irrespective of when it occurs is referred to as the "regional *non-coincident*" station peak.

Transmission line capacity assessments are typically carried out using the regional *coincident* station peak forecast. Station capacity assessments are typically carried out using the regional *non-coincident* station peak forecast. Both types of station peak demand are required by planners for their assessments during the NA phase.

5.2 Forecast Starting Point – Methodology

The forecast starting point is the historical demand for a representative reference year on which the demand forecast is built. The TWG will establish the forecast starting point based on the station-level historical peak electricity demand. Since the historical peak demand includes contributions from distributed generation (DG) and conservation and demand management (CDM) savings at a point in time, it represents net peak demand as opposed to gross peak demand. It should be noted that demand forecasting at the NA phase is designed to facilitate a high-level needs screening exercise that must be completed within 60 days and will include a sensitivity analysis to capture uncertainty.

For the purpose of developing the regional *non-coincident* station peak demand forecast, the TWG will start by looking at the last three to five (3-5) years (from the current year) of historical station-level non-coincident net peak demand. The TWG will then select the most recent historical year that is non-anomalous (i.e., representative of typical/characteristic demand). This non-anomalous year is referred to as the "reference year". The historical station-level non-coincident net peak demand from the reference year is used as the forecast starting point. Note that the LDCs are also asked to verify whether there were any load transfers or other anomalous events that should be disaggregated from the historical data when defining the starting point. The forecast starting point will be adjusted for median and extreme weather by Hydro One TX.

For the purpose of developing the regional *coincident* peak demand forecast, the TWG will typically use the historical station-level regional *coincident* net peak demand from the reference year selected. Again, the forecast starting point will be adjusted for median and extreme weather by Hydro One TX.

5.2.1 Key Responsibilities

- Hydro One TX will provide the historical station *non-coincident* peak demand for each station in the region for the most recent three to five (3-5) years (from the current year) during the NA phase.
- Hydro One TX will provide the historical station *coincident* peak demand for each station in the region for the reference year selected during the NA phase.
- LDCs will also provide their historical net *coincident* peak demand for the most recent three to five (3-5) years (from the current year) as part of their demand forecast submission and it will be used as a reference check.
- Hydro One TX, in consultation with the TWG, will use the above information to establish the forecast starting point.

5.3 Weather Correction Factor

To produce an effective planning forecast, the forecast starting point must be adjusted to both median weather and extreme weather. Hydro One's weather correction methodology will be applied to adjust the forecast starting point for median and extreme weather. The weather-corrected forecast starting point for each transformer station will be provided to the TWG. LDCs will then provide their *gross* demand forecast[6] to the TWG without adjustments for weather.

[6] Guidance and key responsibilities for LDCs to prepare their gross load forecast for the NA is provided in section 5.4 of this document.

5.3.1 Key Responsibilities

- Hydro One will determine and apply median and extreme weather correction factors to the forecast starting point.
- Hydro One will provide the weather-corrected forecast starting point for each transformer station to the TWG.

5.4 Gross Demand Forecast

Once the forecast starting point has been selected and weather-corrected, the LDCs lead the development of the 10-year gross demand forecast. The following are some key inputs that the LDC will account for in their demand forecast:

- Existing customer demand
- New customer loads that have a commitment to connect with the LDC
- Embedded LDC(s) feeder forecasts
- Planned system reconfigurations
- Input from Municipal Energy Plans and/or Community Energy Plans [7] [8]

5.4.1 New Committed Customer Loads

LDCs will include any new committed load customers based on the year(s) they are anticipated to be connected in their gross demand forecast. Non-committed customers should not be included in the gross demand forecast. Instead, non-committed customers can be considered in the sensitivity analysis where the LDC expects they would have a material impact on the demand forecast.

5.4.2 Embedded LDC Feeder Demand Forecast

The host LDC (i.e., LDC directly connected to the transmission system) will include the feeder(s) forecasts from their embedded LDC(s) in the host LDC gross demand forecast.

5.4.3 Seasonal Peak

Regional peaks generally occur during the summer or winter season. In Ontario, regional peaks are mostly during summer for southern regions and winter for northern regions. The gross demand forecast for planning purposes is required for the regional peak season.

[7] An RPPAG recommendation that was endorsed by the OEB related to enhancing coordination between Natural Gas and Electricity Planning applies to this Guideline. For instance, when an LDC is considering the outputs of a CEP (or MEP) in their demand forecast and it involves fuel switching from natural gas to electricity for residential thermal heating or large commercial / industrial process loads, coordination would ensure that the respective planning processes appropriately consider these changes. From a broader perspective, it is also important to ensure key assumptions align such as the level of electrification.

[8] A MEP and/or CEP would be used for NA forecast purposes where: (1) It has been made available to the LDC; and (2) It includes information that the LDC can translate into the impact on peak demand (i.e., not limited to only aspirational goals).

5.4.4 Weather Correction

The LDC forecast should be provided without adjustments for weather since the forecast starting point will already be weather-corrected by Hydro One. The weather correction factors will be determined by Hydro One during the NA phase.

5.4.5 Input from Municipal Energy Plans and Community Energy Plans

LDCs will incorporate input from municipal and/or community energy plans into their gross demand forecast for regional planning purposes where available and can be translated into the impact on peak demand. The RPPAG has developed a guidance document that identifies the information LDCs should request from municipalities related to these plans for use by LDCs in preparing a more accurate demand forecast. If the LDC(s) cannot reconcile the forecast information from the municipal/community energy plan or decides not to include certain assumptions, this should be identified and documented as appropriate. Pursuing alignment between system planning and municipal/community energy planning will contribute to the optimization of combined investment to meet community energy needs.

5.4.6 Gross Demand Forecast – Methodology

In developing the *gross* demand forecast, each LDC in the region will provide their historical (3 to 5-year period) *net coincident peak* demand and future *gross* demand forecast (10-year period). LDCs are required to provide this peak demand information by station/DESN. The peak demand should be the aggregated demand of all feeders at the station and should be coincident with the LDC's system-level peak (or regional coincident peak if TWG prefers), within the relevant region or sub-region. This aggregation will eliminate any errors associated with load transfers. However, where possible, LDCs will also identify and account for any material load transfers between transformer stations to facilitate sub-regional assessments.

Hydro One TX will consolidate demand forecasts from all LDCs in the region by station and will calculate the growth rate for each station/DESN. Since a station may supply more than one LDC, it is quite possible that the peak feeder values from each LDC may not be "coincident" with one another. However, based on prior regional planning experience, using this "non-coincident" information for planning purposes will be of sufficient accuracy as well as conservative to meet the objective of a NA.

To develop the <u>Gross *Non-Coincident* Peak Demand Forecast</u> for the region, the TWG will use the weather corrected historical station *non-coincident* peak demand as the forecast starting point and apply the LDC(s) growth rate from their *coincident* peak forecast to this starting point.

To develop the <u>Gross *Coincident* Peak Demand Forecast</u> for the region, the TWG will use the weather corrected historical station regional *coincident* peak demand as the forecast starting point and apply the LDC(s) growth rate from their *coincident* peak forecast to this starting point.

5.4.7 Key Responsibilities

- LDC to provide their historical net *coincident* peak demand (i.e., coincident with their LDC system-level peak within the relevant region or sub-region) for the most recent three to five (3-5) years. This will be used as a reference check with Hydro One TX historical station *coincident* net peak demand.
- LDC to provide their gross *coincident* peak demand forecast (without adjustments for weather) for a ten (10) year horizon for the NA phase.
- Hydro One TX to consolidate demand forecasts from all LDCs to develop the overall Gross *Non-Coincident* Peak Demand forecast and Gross *Coincident* Peak Demand Forecast.

5.5 Net Demand Forecast – Methodology

There are two main steps involved in preparing the Net Demand Forecast from the Gross Demand Forecast during the NA phase. Those steps involve reflecting the following types of non-wire alternatives:

1. Forecasted Conservation and Demand Management (CDM), and
2. Forecasted Distributed Generation (DG).

The Net Demand Forecast is produced by subtracting the forecasted CDM and DG from the weather-corrected Gross Demand Forecast.

5.5.1 Forecasted CDM

Forecasted CDM demand reductions (i.e., savings) will be estimated and provided by the IESO, in consultation with LDCs, to Hydro One TX. Those estimates will be reviewed by the TWG and incorporated in the Net Demand Forecast. Forecasted CDM savings will reflect the following:

- Estimated savings from building codes and standards,
- Provincial program-related activities typically attributable to IESO administered programs,
- LDC activities approved under the OEB's CDM Guidelines, and
- Federal programs being implemented in Ontario.

Forecasted CDM is considered incremental to the *reference year* (i.e., non-anomalous year selected for the forecast starting point) of the forecast given that the reference year inherently includes existing CDM savings. The IESO will provide the CDM savings ratios at a station level to the TWG, which can be used to derive the megawatt (MW) savings at the station level. Hydro One TX incorporates the forecasted CDM savings in the Net Demand Forecast.

5.5.2 Forecasted DG

Forecasted DG is considered incremental to the reference year of the forecast given that the reference year inherently includes the impact of existing DG. The forecasted DG has typically been based on IESO contract information. However, this data does not include behind the meter generation, nor does it include any other distributed energy resources (DER) that does not have a contract with the IESO. Also, once a contract has expired, the peak contribution from the facility is no longer reflected in the information from the IESO. However, these DG resources may still be contributing after expiry of their contract. To the extent a TWG has information related to such DG resources that are not reflected in the IESO contract information, the TWG should take that DG into consideration.

The equivalent effective capacity for each type of DG is based on IESO capacity factors. They are applied to calculate the expected offset the DG will have on the station peak demand. The capacity factors for the various DG types can vary as a function of season and the region[9]. Hydro One TX incorporates the forecast DG offset in the Net Demand Forecast.

5.5.3 Key Responsibilities

- The IESO will provide the forecasted CDM savings to Hydro One TX for the development of the Net Demand Forecast during the NA phase. The forecast will be given based on the breakdown discussed above (i.e., building codes and standards, provincial programs, etc.). The TWG will review the forecast provided by the IESO to determine whether any adjustments are required to reflect local circumstances.
- The IESO will provide the forecasted installed DG capacity and associated capacity factors based on IESO contract information to Hydro One TX for the purposes of the NA. The TWG will determine the appropriate way to reflect the peak contribution of this DG given the characteristics of the region and the availability of additional information.
- Hydro One TX will incorporate the Forecasted CDM and DG in the Net Demand Forecast

5.6 Sensitivity Analysis – Methodology

The objective of a sensitivity analysis is to capture uncertainty in the demand forecast as well as variability of drivers such as DG, electrification, etc. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather will be used to identify any emerging needs for consideration in developing recommendations.

Some of the key electric demand drivers may include the following:

- Potential evolution of public policy
- Electrification (e.g., electrification of transportation or other sectors)[10]
- Municipal Energy Plans, Community Energy Plans, and Climate Action Plans (for actions that are not firm/committed)
- Non-committed customer connections (both distribution and transmission)
- DER scenarios (e.g., battery storage)
- Continued operation of off-contract generation facilities
- Other

[9] For hydroelectric facilities, the assumed output at the time of peak demand is often taken as the output that is available 98% of the time, based on historical data. This ensures that the peak output during low water (e.g., drought) conditions is reflected in the studies.

[10] The November 2021 Mandate Letter to the OEB, from om the Minister of Energy, stated: “Increased adoption of electric vehicles (EVs) is expected to impact Ontario’s electricity system in the coming years and the OEB must take steps to facilitate their efficient integration into the provincial electricity system”. This is a quickly evolving area and the RPPAG intends to closely monitor the pace of EV adoption between biannual reviews of this Guideline to ensure it is appropriately reflected.

The TWG is in the best position to develop regional sensitivity scenario forecasts. It is worth noting that the demand forecast is already adjusted for extreme weather correction. Taking the key electricity demand drivers into consideration (as mentioned in section 2 above), a high and low demand growth forecast should be developed to identify any additional and/or advancement / deferment of investments.

For the high and low growth scenarios, the TWG can determine a "+/- fixed percentage" to apply to the net demand forecast. For example, adjustment factors should typically be no more than +/- 50% of the station growth. The TWG may consider and document other approaches to developing the sensitivity scenarios according to the demand driver under study and the data available.

6. IRRP: Developing the 20-Year Planning Forecast

For the purposes of the Integrated Regional Resource Plan (IRRP), a 20-year extreme-weather net peak demand forecast is developed to assess the reliability of electricity supply over the planning horizon. This forecast is termed the "Planning Forecast" as it underpins the plan. This section of the guidance document outlines the process, data requirements and leads for each key component of the IRRP planning forecast.[11]

6.1 Forecast Starting Point

Similar to the NA, the forecast starting point is the historical demand for a representative reference year on which the demand forecast is built. The IESO will lead and execute the development of the starting point for the IRRP and the TWG will review and approve the starting point for use in downstream steps of forecast development.

Developing the reference year and starting point requires several considerations relevant to the region as outlined below; each of which is described in the sections that follow:

- *Compile Data* - including the historical hourly station level demand, installed DG in the region and its historical hourly output, and other data related to historical distribution load transfers, Industrial Conservation Initiative (ICI) activations and customer segmentation

- *Unbundle DG* – to determine the gross historical hourly station level demand

- *Determine the Type of Forecasts Required* – to determine the approach to regional coincidence

- *Determine the Linear Demand - Weather Relationship* – to translate the historical station demand to median weather conditions, and the median demand forecast to extreme weather conditions in subsequent steps of forecast development

[11] It has been quite rare, but the process contemplates a RIP being undertaken directly after the Scoping Assessment (i.e., no IRRP). This would occur where only a wires solution would meet the need and it would be relatively straightforward. In such cases, the NA forecast would be used for the RIP, unless there has been a material change. If there is a material change, the IESO will do an expedited IRRP using the load forecast approach that is most appropriate to ascertain if NWAs become an option.

- *Prepare the Forecast Starting Point* – to review with the TWG for their agreement and for the LDCs to use as a launch point for their forecast.

6.1.1 Compile Data

This section outlines the data that is compiled by the IESO to support the development of the planning forecast. This step leverages data sets from the IESO, Hydro One and the LDCs as noted throughout.

Historical Hourly Demand

The historical hourly demand is compiled at a station level, by LDC, using IESO settlement data. A historical period of five (5) years is used where applicable.

DG

Data on DG can vary from region to region because not all of these resources are visible. The following data sources are typically used to obtain information on resource capacity, hourly historical output and capacity factor:

DG Data Category	Sources
Capacity	• IESO contract data (contracted capacity) • Hydro One DG capacity data (installed capacity)[3]
Hourly Production	• IESO renewable operations data • Hydro One meter data[12]
Capacity Contribution at time of Peak Demand (by resource type)	• IESO Reliability Outlook (factors are produced at a zonal level) • Other studies of the DG in the region

These data sources often do not fully represent the DG within a particular region. Other data sources that may be useful include those data sets from the LDCs for DG in their service territories. As more data on DG becomes available, the methodology outlined in this document will be updated accordingly.

Other Data

LDCs provide other data to the TWG including historical distribution transfers between stations, ICI program impacts[13] and the customer segmentation by station[14], as available and appropriate.

6.1.2 Unbundle DG

Unbundling DG output from the historical hourly station level demand can be an important step in the IRRP, especially where there is appreciable penetration of DG. In these instances, unbundling helps to reflect true station demand patterns and ensure accurate accounting of DG in the planning

[12] Hydro One data includes DG in areas where Hydro One is the LDC.
[13] Under the Industrial Conservation Initiative (ICI), Class A customers can reduce/shift demand substantially during the “high 5” peak periods
[14] Percent (%) of historical demand consumed by residential, commercial and industrial customers.

forecast. Unbundling is led by the IESO and involves creating a historical hourly output profile of DG which is added to historical hourly station level demand.

Ideally, a profile of historical hourly output would be available and complete such that it could be used directly in the unbundling. This is not always the case given the availability of data, so various steps are taken to prepare a profile with the best data available. These steps are described below:

1. IESO renewable operations data is used directly where available.
2. Hydro One-meter data and installed capacity is then used to generate an hourly profile of capacity factors for resources for which no IESO renewable operations data exists. The profile of capacity factors is converted to an hourly output format by using the IESO contract capacity data; this ensures that the data is normalized to IESO-verified data.

Once the historical hourly output profile of DG is created, it is added to the historical hourly station level demand to obtain the gross historical hourly station level demand.

Note that in some regions – particularly those with low penetration of DG – the effort to produce a historical hourly output profile of DG may not be worthwhile given its limited impact on the station demand trends. In these instances, a simplified approach may be used whereby the historical amount of DG output at the time of peak is estimated using a resource specific capacity contribution together with the contracted capacity from the IESO contract data. Alternatively, the TWG may determine to forgo this step. These alternative approaches should be considered a variation to the baseline approach described above, and rationale will be documented in the IRRP.

6.1.3 Determine the Type of Forecasts Required

In this step, a determination is made on the number and type of forecasts required for the IRRP in the context of seasonal peak and regional coincidence. In the regional planning context, the demand at a given station at the time when the aggregate regional demand is highest is typically referred to as the "regional coincident" station peak, whereas the highest station demand irrespective of when the aggregate regional demand peaks is referred to as the "regional non-coincident" peak. Further, the regional non-coincident peak is coincident from the station perspective, meaning that if there is more than one LDC served by a station, only the overall station peak is required -- not the individual LDC peaks.

Transmission system assessments, which are used for capacity planning, are typically undertaken with the regional coincident forecast, whereas station equipment capacity assessments are typically undertaken with regional non-coincident forecasts. For this reason, both a regional coincident and regional non-coincident forecast is required for the IRRP; however, a choice exists on whether the regional non-coincident forecast is developed first and translated through a coincidence factor to regional coincident, or vice versa. Further, depending on the needs being studied within the IRRP, the TWG may elect to study more granular levels of coincidence (i.e., at the sub-region or load-pocket[15] level). These choices impact the approaches used to define the linear relationship between historical demand and weather through the weather correction process, as well as the selection of the forecast starting point.

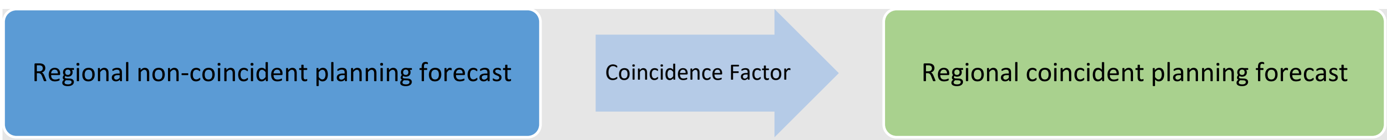
[15] Load-pocket refers to a grouping of stations with similar load characteristics that contribute to an upstream need.

In general, there are two key approaches for developing the forecasts for the IRRP as they relate to regional coincidence. These approaches are discussed below, along with the considerations that lead to the selection of the number and type of forecasts required within the IRRP.

<u>Approaches</u>

Approach 1: Start with Regional Non-Coincident Forecast

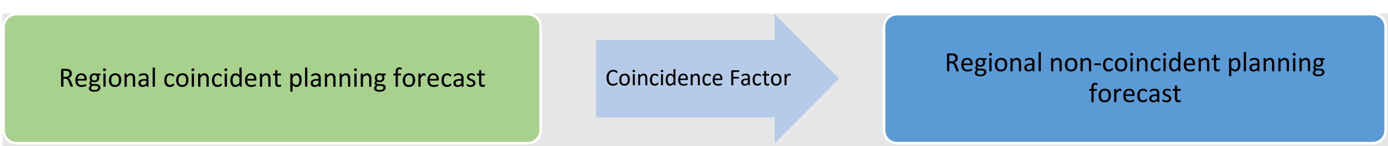
The most conservative approach is to develop a regional non-coincident forecast and use this forecast for both the transmission system assessments and station capacity assessments. If no needs are identified with this forecast, a regional coincident forecast is not required as the regional non-coincident forecast is higher than the regional coincident forecast by definition. If needs are identified using the regional non-coincident forecast, a regional coincident (or sub-region or pocket[16] coincident) forecast will be developed through the use of a coincidence factor to refine the determination of the needs. The coincidence factor is the average ratio of the historical station demand at the time of the region's overall peak to the historical station demand at the time of its individual peak. Note that all subsequent references to regional coincident should be interpreted as regional coincident, or sub-region or pocket coincident).



This approach requires the weather correction process to be conducted on a station-by-station basis to determine the linear relationship between demand and weather (see considerations below).

Approach 2: Start with Regional Coincident Forecast

Another approach is to develop a regional coincident forecast and use this forecast for the transmission system assessment. A regional non-coincident forecast is developed through the use of a coincidence factor, which in this case is the average ratio of the historical station demand at the time of its individual peak to the historical station demand at the time of the region's overall peak.



In the instance that other approaches are used, the IRRP report will document the rationale and describe the characteristics of the region that warrant the approach.

[16] A pocket is a grouping of stations, within a region or sub-region, that together, contribute to an upstream reliability need.

Considerations

Seasonal peaks: In what season does the region's annual peak occur? Is the region summer or winter peaking? Is this consistent within the historical data? Are there sub-regions or pockets within the region that peak in different seasons?

Demand profile characteristics: Do the station demand profiles generally match that of the overall region? Are there pockets or sub-regions where the profiles are substantially different such that they peak at a different time than that of the region? Does the weather-demand relationship vary between stations or sub-regions?

Customer segmentation: What is the customer segmentation at each station? Is the customer segmentation consistent across the region? Are there groups of stations with similar segmentation?

Insight on needs: Are the needs well understood and characterized from previous plans and studies? Is there latitude to start defining pockets and coincident forecasts by pocket? Or will the region benefit from a comprehensive review starting with the regional non-coincidence forecast as it is more conservative?

Load transfers: Does a region, or pocket of stations within a region, typically have significant load transfers between stations?

Demand growth trend: Is the demand in the region expected to grow according to annual growth rates or is there a new customer expected to come into service which will introduce a step-change into the forecast?

Demand anomalies: Were there any demand anomalies or changes reflected in the historical data (e.g., the pandemic, outages, load transfers, customer interruptions)? To what extent are these changes expected to continue in the future?

Selection

	Approach 1 – Regional Non-Coincident	**Approach 2 – Regional Coincident**
Considerations that guide Selection	• Stations, or pockets of stations, may peak in different seasons • Stations, or pockets of stations, may have different demand profile characteristics and/or customer segmentation • Needs not yet well defined or characterized (e.g., regions for which no previous IRRP exists) • Appropriate for both annual growth rates and bulky step changes; however, this approach is considered best when you have bulky step changes in the demand	• Consistent seasonal peaks • Consistent demand profile characteristics and customer segmentation • Needs well understood from previous plans and studies • Transformer stations with a high degree of load transfers between stations • Annual growth rates as opposed to bulky step changes without supporting consumption profiles

	without accompanying consumption profiles	

The outcome of this step is a determination of what forecasts will be initially prepared for the IRRP; i.e., which season (summer or winter) and the approach to regional coincidence (regional or sub-region/pocket coincident, or regional non-coincident).

6.1.4 Determine the Linear Demand – Weather Relationship

This section describes the approach used by the IESO to determine the linear demand-weather relationship as part of regional planning.[17] This process is led by the IESO, and the resulting adjustment factors are reviewed and agreed to by the TWG prior to establishing the forecast starting point.

The approach used to determine the linear demand–weather relationship depends on the type of forecast that will be initially prepared for the IRRP. In general, this relationship is defined on the same basis as the forecast type. When a regional coincident forecast is prepared first, the demand – weather relationship is similarly defined on a regional coincident basis. Conversely, when a regional non-coincident forecast is prepared first, the relationship is defined on a regional non-coincident basis (i.e., station by station).

With this difference in mind, the following steps are taken using the IESO's in-house tools to define the relationship and to determine median and extreme weather correction factors.

- 30 years of historical weather data is obtained from the appropriate (i.e., closest) weather station.

- Daily maximum temperature is typically used to represent the weather in summer peaking regions, and daily minimum temperature is typically used to represent the weather in winter peaking regions.

- The 3-day rolling average of historical daily minimum / maximum temperatures is plotted against the historical daily peak demand[18] to obtain the linear relationship between the two variables for each historical year of demand. Note that weekends and holidays are excluded when developing this relationship.

- The historical maximum / minimum annual temperature is ranked in ascending order to obtain "Median Weather" (50th percentile) and "Extreme Weather" (highest or lowest value observed in 30 years).

- These "Median Weather" and "Extreme Weather" values are used in the linear relationship to determine the respective Median and Extreme adjustment factors for each historical year of peak demand.

[17] The IESO employs a different methodology when producing the provincial demand forecast and, thus, there is an opportunity to align these methodologies in the future as they continue to evolve, if appropriate.
[18] Either regional coincident daily peak or regional non-coincident daily peak

As noted above, the historical daily peak demand will either be regional coincident, or regional non-coincident depending on the type of forecast initially being prepared for the IRRP. The historical demand will also be unbundled from DG output as per section 6.1.2.

When the linear relationship derived from weather correction is a poor fit of the data, a choice may be made by the TWG to either forgo weather correction (at a particular station) or to choose a different approach such as aligning with the LDCs or transmitter's adjustment factors. In these cases, the IRRP report will provide the rationale for the approach used.

When preparing the starting point, the median weather adjustment factor is applied to the annual historical peak data to translate the historical data to median weather conditions. When a regional coincident approach is initially selected, the regional annual historical peak demand is determined and the median weather adjustment factor is applied. This is broken down to a station level through a distribution factor which is the ratio of non-weather adjusted demand at the station at the time of the coincident peak to the coincident peak of the region. This is important because the forecast is developed on a station-level basis. When a regional non-coincident approach is initially selected, the median weather adjustment factor determined for each station is applied to the annual historical station level peak.

6.1.5 Prepare the Forecast Starting Point

The forecast starting point is the historical demand for a representative reference year at a particular station on which the demand forecast is built. The TWG will establish the forecast starting point based on the unbundled and weather adjusted station-level historical peak electricity demand, on a regional coincident or regional non-coincident basis, as defined when determining the type of forecast to be initially prepared for the IRRP. The TWG, including LDCs, are also asked to verify whether there were any load transfers or other anomalous events that should be disaggregated from the historical data when defining the starting point.

The station starting point is typically represented as the peak station demand observed during the last historical year; however, other approaches can be taken if the last historical year is not suitable and representative of the reference demand from which the forecast should launch. The rationale and methodology for other approaches will be documented within the IRRP report.

Once the forecast starting point has been agreed to by the TWG, it is used by the LDCs to facilitate the development of the demand forecasts for their respective territories. If multiple LDCs are served by a station, the starting point for each LDC is apportioned according to their historical contribution to the station peak.

6.1.6 Key Responsibilities

- The IESO will compile data, unbundle DG output, lead the determination of the number and types of forecasts required, determine the linear demand-weather relationship and prepare the forecast starting point.
- LDCs will provide historical distribution transfers, customer segmentation by station, historical ICI activations, as available and applicable.

6.2 Gross Forecast

The LDCs lead the development of the 20-year gross demand forecast which is prepared to reflect median weather and growth conditions. This forecast is prepared on the basis of the regional coincidence approach determined as part of the determination of the starting point. For example, if after reviewing the demand characteristics of the region the TWG determined that the forecast will first be prepared using a regional coincidence approach, the LDCs will prepare the gross forecast on this basis, and vice versa. The LDC forecasts are gross in that they only consider existing CDM savings up to the starting point (reference year), and their persistence thereafter, and do not account for peak output from DG; forecasts of new CDM savings and peak output from DG will be accounted for in the development of the planning forecasts. Where possible, LDCs should not include past trends related to the ICI program in the gross forecast. The key steps in the development of the gross forecasts for the IRRP are discussed in this section of the guidance document.

6.2.1 Key Inputs into the Gross Forecasts

Key inputs that the LDC will account for in the development its gross demand forecast include:

- New and committed load customers
- Embedded LDC(s) feeder forecasts
- Planned system reconfigurations
- Input from Municipal Official Plans and Community Energy Plans (see section 5.4.5 for further details)

LDCs will include any new and committed[19] load customers by year(s) of anticipated connection. Non-committed customers that may have a significant impact on the demand forecast can be considered in the sensitivity analysis given that it is not certain that they will materialize. A similar approach is used with respect to Community Energy Plans (i.e., committed projects will be captured in the gross forecasts, whereas non-committed projects and plans can be considered in the sensitivity analysis). LDC forecasts also include existing CDM savings in their forecast, but should not include future savings from programs, and codes and standards.

In the instance of embedded LDCs, the host LDC (i.e., directly connected to the transformer station) will include the feeder(s) forecasts from their embedded LDCs in their demand forecast.

LDCs will document their methodology and assumptions in the development of the gross forecasts in the IRRP. This documentation will consider the following components where feasible and applicable:

- What are the overall main drivers of the gross forecast?
- What significant growth factors are included?
- What are the key sectors driving the forecast?
- What electrification has been considered as part of the gross forecasts?

[19] Committed refers to customers with an Offer to Connect (OTC) from their LDC and may also include potential customers that are in the final steps of receiving an OTC in the near-term.

- What are some of the factors that should be considered as part of sensitivity analysis given the underlying assumptions in the gross forecast

As mentioned above, one of the evolving components with respect to the demand for electricity is electrification which is expected to change the growth patterns such as they are not well represented by historical trends. LDCs should include assumptions with respect to electrification available in Community Energy Plans or employed in the IESO's provincial demand forecast which can be translated from an IESO zonal level to the region being studied. This can also be a consideration of the sensitivity analysis.

6.2.2 Output of the Gross Forecast

The LDCs will provide a gross, median weather, median growth, peak demand forecast in MW by station. This forecast is informed by the forecast starting point and reflects any significant step changes not captured in the reference year. This forecast represents the season in which the annual historical peak occurs. If possible, LDCs are encouraged to provide forecast details by customer sector as this will assist in the calculation of forecasted CDM savings.

The gross forecast provided by the LDCs will be adjusted to regional coincident, as required, through the use of a coincident factor; i.e., for each historical year, the ratio of the station peak at the time of the regional coincident peak to the individual station peak. Coincident factors can be averaged over five (5) years; i.e., the typical historical period considered as part of the IRRP demand forecast development. If the gross forecast is initially developed on a regional coincident basis, it is converted to a regional non-coincident basis through the inverse of the coincident factor described above.

6.2.3 Key Responsibilities

- LDCs provide their median weather and growth demand forecast for a 20-year horizon to the IESO.
- The IESO will compile the LDC forecasts and calculate the coincident factors and translate the demand to regional coincident, or regional non-coincident, as appropriate.

6.2.4 Planning Forecast[20]

Once the gross, median weather and median growth forecasts are prepared by the LDCs and compiled by the IESO, the next step is to develop the planning forecast which reflects CDM savings and peak contribution from DG forecasted over the 20-year planning timeframe, as well as extreme weather. Note that the forecast of CDM savings and contribution from DG should reflect the season considered in the development of the gross forecast. For example, if the gross forecast reflects summer peak, the CDM savings and contribution from DG should also reflect summer peak conditions. The IESO leads the development of the planning forecast and it is reviewed by the TWG.

[20] The planning forecast is net of forecasted CDM savings and peak contribution from DG.

6.2.5 Conversion to Extreme Weather

Transmission planning standards require transmission system assessments to be carried out under extreme weather conditions. Therefore, the gross, median weather and median growth forecast prepared by the LDCs are translated to extreme weather conditions using the average historical extreme weather factors determined in the development of the starting point (see section 6.1).

6.2.6 Forecasted CDM Savings

Forecasted CDM savings will be developed by the IESO and reviewed in consultation with the TWG for incorporation into the planning forecast. Forecasted CDM savings include estimated savings from building codes and standards and program-related activities typically attributable to Provincial programs, as well as Federal programs resulting in savings in Ontario, and are based on the season that defines the forecast. Incremental CDM, beyond committed programs, is explored as part of the demand sensitivity analysis.

Forecasted CDM savings that are incremental to the forecast reference year are considered in the planning forecast, given that the reference year inherently includes existing CDM savings. The IESO will provide the forecasted CDM peak reduction ratios at a station level, which are used to derive the MW savings at the station level. In addition to CDM estimated by the IESO, some local municipalities may fund and administrate their own CDM programs. The LDCs are encouraged to provide the planned savings at the relevant stations for these programs as a separate line item.

6.2.7 Peak Contribution from Forecasted DG

The peak contribution of forecasted DG is typically based on IESO contract information. However, this data does not include net or behind the meter generation, nor does it include any other DG resource that does not have a contract with the IESO. Therefore, the planning forecast will not capture the full range of potential future DG uptake. To the extent the TWG has information related to DG resources that are not reflected in the IESO contract information, the TWG should take that DG into consideration. In doing so, the TWG should use its best judgement to determine the appropriate way to reflect the peak contribution of that forecasted DG given the characteristics of the region and the availability of additional information. An opportunity exists to evolve the approach to developing forecasts of DG within a particular region. While assessing potential changes in approach are outside of the scope of this guidance document, if the RPPAG concludes a proposed new approach should be adopted (or identified as an option for specific regions), this guidance document will be revised to reflect that new approach.

The IESO will calculate the peak contribution from the DG resources, by season, in the IESO contract data using the resource specific capacity contribution which represents the percentage of the resource's installed capacity that can be relied on at the time of the peak demand[21]. The TWG will determine the appropriate capacity contribution that will be used given the need to reflect regional characteristics in the approach.

[21] For hydroelectric facilities, the assumed output at the time of peak demand is often taken as the output that is available 98% of the time, based on historical data. This ensures that the peak output during low water (e.g., drought) conditions is reflected in the studies.

It should be noted that the current practice with respect to contracted generation is to include it the planning forecast only until the facility's contract expires. Sensitivity studies may be considered with these resources included after contract expiration. If other approaches are determined appropriate by the TWG the rationale will be provided in the IRRP report.

6.2.8 Key Responsibilities

The IESO will convert the aggregated LDC gross median weather forecasts to extreme weather, calculate the forecast CDM savings and peak contribution from DG and assemble the planning forecast.

6.3 Consideration of Planning Forecast Sensitivities

It is recommended that sensitivity scenarios be considered in the IRRP, as determined by the TWG, recognizing that the future could be different from that modeled in the planning demand forecast. The purpose of the sensitivity scenarios will help the TWG understand the flexibility of the plan, and set signposts of change that should be monitored in the future; i.e., to understand whether demand is growing more quickly or slowly than anticipated and whether the next cycle of regional planning should be initiated early. The results of sensitivity analysis are not necessarily meant to drive investment. Instead, they are meant to inform the flexibility of the plan and to identify any potential needs under different scenarios that should be monitored after plan completion.

6.3.1 Sensitivity Drivers

Some key electric demand drivers that may be considered in a sensitivity scenario include:

- Potential evolution of public policy
- Electrification (e.g., electrification of transportation, buildings or other sectors) impact to both winter and summer peak demand[22]
- Municipal Energy Plans, Community Energy Plans, and Climate Action Plans (for actions that are not firm/committed)
- Non-committed customer connections (both distribution and transmission)
- Range of potential future customer connections in growth sectors (e.g., mining and greenhouses)
- DER scenarios (e.g., battery storage)
- Continued operation of off-contract generation facilities
- Impacts of climate change on the demand-weather relationship
- Lasting pandemic impacts (e.g., remote working)
- Impact of ICI activations as it relates to Class A loads
- Potential CDM, above and beyond that committed

[22] The November 2021 Mandate Letter to the OEB, from the Minister of Energy, stated: "Increased adoption of electric vehicles (EVs) is expected to impact Ontario's electricity system in the coming years and the OEB must take steps to facilitate their efficient integration into the provincial electricity system". This is a quickly evolving area and the RPPAG intends to closely monitor the pace of EV adoption between biannual reviews of this Guideline to ensure it is appropriately reflected.

These drivers may also be factored into the planning demand forecasts if there is sufficient data and they are considered committed (refer to section 6.2.1). There may be other drivers that are relevant in a particular region, and these will be discussed on a case-by-case basis with the TWG and documented in the IRRP report. There may also be instances where some of the sensitivity drivers noted above are considered as options to meet identified needs, as part of an IRRP, rather than factored into the sensitivity analysis. The IRRP will include the assumptions associated with the sensitivities considered in the plan, and their sources. The IRRP will identify when TWG judgement was used.

6.3.2 Sensitivity Methodology

The TWG is in the best position to develop the methodology for the sensitivity scenario forecasts as it will depend on the relevant regional drivers. However, the TWG should consider a high and a low sensitivity of the reference planning forecast, where applicable. The sophistication of the approach is dependent on the availability of information related to the key drivers and their impact on regional peak demand. The available information is expected to evolve over the coming years, and so too will the approach to sensitivities. It is recommended that the TWG members discuss what data exists amongst members and can be shared to support LDC development of demand forecast sensitivities.

Some current examples of how sensitivities can be developed include: applying a fixed +/- percentage to the annual growth rates (caution should be taken to ensure that the adjustment is not equal to or greater than 50% of a station's annual growth rate); or by the LDCs using data obtained from the IESO at a zonal-level (and employed in the IESO's provincial demand forecast) to develop a sensitivity regarding electric vehicle uptake in their service territory. Other approaches have also been used to create different potential future pathways related to customer connections in a particular sector, such as mining for plans in Northern Ontario. These scenarios are developed through stakeholder engagement and outreach and research of the commodities and mining sector. This information ultimately results in a low, reference and high scenario, formed through application of project-level likelihood factors and scenario probabilities.

7. Conclusion & Future Evolution: NA and IRRP Demand Forecast Processes

This document outlines the RPPAG's guidance to be utilized by the TWG in the development of the demand forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP stages. As discussed throughout this document, a key factor in the development of the demand forecasts is flexibility to reflect local characteristics and circumstances. The approaches outlined in this guidance document are meant to form a basis for the general process; variations from these approaches shall be adequately documented in the NA and IRRP reports, respectively, to ensure transparency.

It is recognized that the demand forecast process will continue to evolve over time with consideration of changing weather patterns due to climate change; evolving end-uses due to electrification; DG visibility and data availability; and general improvements to tools and methodologies used in other demand forecast processes such as the IESO's provincial demand forecast and that of LDCs. Thus, as noted above, the RPPAG plans to review this guidance document every two years to ensure it still reflects the basis for the general process that is typically followed. Further, more frequent and targeted reviews of this guidance document may be undertaken, from time to time, should it be warranted based on emerging issues.

GLOSSARY

Conservation and Demand Management (CDM) – in Ontario, CDM refers to activities aimed at reducing peak electricity demand and/or electricity consumption from the electricity system.

Dual Element Spot Network (DESN) – a concept that provides redundancy in the form of duplication for most station components. An example includes a concept with two transmission lines, two transformers, and two voltage busses.

Gross Demand – electricity demand without consideration of distributed generation output and CDM savings.

Historical Peak Demand – highest electricity demand in a historical data set.

Integrated Regional Resource Plan (IRRP) – a document prepared by the IESO that identifies the appropriate mix of investments in one or more of CDM, generation, transmission facilities or distribution facilities in order to address the electricity needs of a region in the near- (up to 5 years), mid- (5 to 10 years), and long-term (more than 10 and up to 20 years)

Needs Assessment (NA) – a process led by a transmitter (e.g., Hydro One) to determine if there are needs (e.g., reliability) in the planning region and, if so, whether coordinated regional planning is needed.

Non-anomalous Year – year of historical demand that is representative of the typical/characteristic demand.

Peak Capacity – amount of output from a resource at the time of system peak demand.

Forecast Peak Demand – highest electricity demand that has occurred in a forecast data set.

Reference Year – non-anomalous year selected for the demand forecast starting point.

Regional Coincident Peak Demand – sum of demand observed at the transformer stations at the hour when overall demand in the region is at its highest.

Regional Infrastructure Plan (RIP) – a document prepared by the transmitter (e.g., Hydro One) leading a regional infrastructure planning process that identifies investments in transmission facilities, distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within a region.

Regional Non-Coincident Peak Demand – sum of each transformer station's individual peak demand, regardless of whether the stations peak at different times.

Segmentation – splitting of electricity demand into customer sector e.g., residential, commercial and.

Starting Point – the demand for a reference year on which the demand forecast is built.