# RPPAG Report to the OEB

## Recommendations to Improve Ontario's Regional Planning Process

**Prepared by the Regional Planning Process Advisory Group (RPPAG)**

**EB-2020-0176**

**December 20, 2021**

# Table of Contents

# 1. Introduction and Overview of RPPAG Recommendations

## Introduction

On December 20, 2020, the Ontario Energy Board (OEB) issued a letter to initiate a consultation process to undertake a review of the regional planning process in Ontario. The letter indicated the primary purpose of the review is to improve the efficiency and effectiveness of the current process.

On January 18, 2021, the OEB issued another letter that re-established its Regional Planning Process Advisory Group (RPPAG) to assist in this review. The January 18th letter indicated the objective for the RPPAG is to provide a set of recommendations related to potential changes to the regional planning process for consideration by the OEB which may result in both proposed changes to the current regional planning process and/or amendments to one or more of the OEB's applicable regulatory instruments that underpin the process, including the Distribution System Code (DSC), Transmission System Code (TSC), the IESO's licence and utility application filing requirements. The current membership of the RPPAG is set out in Appendix A.

The OEB identified that the initial focus of the RPPAG was to further assess certain high-level recommendations from the review completed by the Independent Electricity System Operator (IESO) that the OEB is taking the lead on, as identified in the IESO's Final Report. OEB staff clarified during the meetings that a cost recovery issue associated with distributed energy resources (DERs) that was identified in the IESO Report was related to remuneration – utility disincentives to use third party DER providers – and is to be examined by the OEB's Framework for Energy Innovation (FEI) working group.[1]

The OEB's January 18th letter further indicated the scope of the RPPAG's work was not limited to assessing those IESO recommendations as there may be other areas where additional process improvements can be made.

To that end, the RPPAG has made additional recommendations that are not related to those in the IESO's Report.

[1] The RPPAG had requested further clarification because the OEB FEI letter noted remuneration issues would be addressed as part of a "future phase". OEB staff further clarified that this "disincentive" issue would be addressed as part of Workstream #1 and the FEI letter reference to "remuneration" being addressed in a "future phase" is broader in nature than that cost recovery issue.

The RPPAG held its first meeting on February 17, 2021 and general agreement on almost all of the recommendations was achieved at our seventh meeting on September 21, 2021.

This report sets out the RPPAG's recommendations to the OEB and is organized as follows.

- The first section provides a high-level summary of the RPPAG's recommendations and the associated expected outcomes.

- The second section provides an explanation of the current regional planning process in Ontario to provide context for those recommendations.

- The final two sections of the report provide a more detailed discussion of each recommendation including some which relate to potential changes to the OEB's regulatory instruments for the OEB's consideration.[2] The recommendations related to the IESO Final Report are first discussed. A discussion of the RPPAG's other additional recommendations then follows.

Where this document recommends revisions to the RPPAG Report setting out the regional planning process (e.g., establishing new criteria), the current RPPAG would make the changes that are endorsed by the OEB in its role as a permanent ongoing OEB advisory group (as noted in the OEB's December 10th letter).[3]

## Overview of RPPAG Recommendations and Expected Outcomes

The following is a high-level summary of the RPPAG's recommendations and the expected outcomes if those recommendations are endorsed by the OEB and implemented. There are four recommendations related to the IESO's Report. That is followed by a discussion of the additional recommendations that the RPPAG believes

[2] If all the RPPAG's recommendations are accepted by the OEB, it would result in the OEB making amendments to the following regulatory instruments: *Distribution System Code (DSC), Transmission System Code (TSC), IESO licence, CDM Guidelines, Filing Requirements for Leave to Construct (LTC) Applications, Filing Requirements for Rate Applications, 2006 Bulletin (cost responsibility), as well as the creation of a new Bulletin (local preferences).*

[3] The RPPAG understands that the 2013 Process Planning Working Group (PPWG) Report will be renamed the RPPAG Report after it is revised to incorporate the RPPAG's recommended changes that the OEB endorses. It is therefore referred to as the RPPAG Report in this document.

will improve the efficiency, effectiveness, and transparency in relation to the current regional planning process.

### IESO-RELATED RECOMMENDATIONS

1) **Standardize & Streamline Load Forecast Development**

   Establish a Load Forecast Guideline to increase consistency in the methodology (e.g., assumptions) used by LDCs to prepare their load forecasts. This should result in a more accurate determination of regional needs and eliminate the current inefficiency related to the IESO standardizing information when aggregating LDC forecasts (at the regional level) at the end of process.

   The RPPAG is currently in the process of creating the Load Forecast Guideline as part of implementation of this recommendation.

2) **Clarify Scope between the Integrated Regional Resource Plan (IRRP) and Regional Infrastructure Plan (RIP) – Wires investments**

   Revise the RPPAG Report that sets out the current regional planning process to make the scope of the Regional Infrastructure Planning (RIP) process and the Integrated Regional Resource Planning (IRRP) process more clearly defined in relation to wires solutions – transmission and distribution – to eliminate any duplication of work that currently exists between the IESO and lead transmitter (i.e., Hydro One), and therefore increase overall process efficiency.

3) **Better Consideration of Cost Responsibility in the regional planning process**

   Prepare an OEB staff plain language document that explains the key cost responsibility rules related to regional planning to achieve a common and correct understanding of the rules, particularly among smaller LDCs, to better inform solutions that are recommended in regional plans.

   Prepare a new OEB Bulletin that incorporates OEB guidance related to “local preferences” to better inform communities that they have a choice to opt for a “premium” solution (e.g., DER, rather than wires) and the related cost responsibility consequences if they choose the “premium” solution; i.e., higher cost than the “optimal” (or most cost effective) solution. The RPPAG believes this guidance on cost responsibility will become increasingly important as the barriers to innovative technologies, such as DERs, are reduced through initiatives such as the OEB’s Framework for Energy Innovation (FEI). A review of that Bulletin is recommended once the OEB’s FEI initiative reaches a conclusion on assessing the value of DERs relative to traditional wires investments, as that may change how the “optimal” solution is defined.

An update to the OEB’s September 2006 Bulletin that explains the circumstances under which transmission Network upgrade costs should be paid for by a specific customer to increase stakeholder awareness and add clarity.

4) **Better Address End-of-Life (EOL) Asset Replacement in the regional planning process**

Establish a mechanism (i.e., DSC & TSC amendment) that requires all transmission asset owners (TAOs), including the applicable LDCs, to provide a 10-year outlook of *end of life (EOL)* information related to major transmission assets to the IESO and the lead transmitter. Doing so would ensure all EOL asset replacement options across the province are appropriately assessed before a decision is made, as part of the regional (and bulk) planning process.

Formalize a process where Hydro One provides a list with the asset demographics (i.e., facility age) for all major transmission assets to the IESO (and all interested stakeholders). This longer-term outlook would allow for consideration of an asset’s *expected service life (ESL)* in the planning process to provide more lead time to evaluate non-like-for-like replacement options – including non-wire alternatives such as DERs – before those transmission assets reach EOL.

### “OTHER” ADDITIONAL RECOMMENDATIONS

5) **General Education on Regional Planning Process to Stakeholders**

Undertake a general education initiative to facilitate a better general understanding of how the regional planning process works among stakeholders and the information that is required / available. More informed stakeholders should result in a more efficient and effective regional planning process.

Education on the linkages between regional planning and other types of planning processes (e.g., community energy planning) should also be beneficial, particularly in terms of improving coordination and alignment between the planning processes.

This education initiative would also ensure LDCs, other transmitters and interested stakeholders are better informed of the modifications to the process resulting from RPPAG's recommended changes that are endorsed by the OEB (e.g., new Load Forecast Guideline) to ensure a smooth transition.

**6) Holistic Coordination of Planning Processes – Regional, Bulk, Distribution, Natural Gas, Municipal**

*Regional* planning is key in Ontario due to the large number of LDCs. It also has linkages to *bulk* system planning, which focuses on addressing provincial electricity needs, and *distribution* planning which addresses needs at the local community level. Due to those linkages, coordination between those planning processes is important to ensure that the optimal (i.e., most cost effective) solutions are implemented. *Municipal* planning information is also a key input in the regional planning process in determining the system needs that must be met. *Natural gas* planning in Ontario is also evolving with the adoption of an Integrated Resource Plan (IRP) and coordination with electricity regional planning should be enhanced. This recommendation focuses on enhancing coordination among those four types of planning.

*Bulk Planning:* Preparation of a single IESO document that summarizes all planned transmission (and generation) investments that span multiple contiguous regions (in various related bulk & regional plans) with linkages to the transmission investment in a leave to construct (LTC) application should result in more informed OEB Panel decisions and a more efficient OEB regulatory process. It should also increase accountability, as there will be a need to demonstrate that all the interdependencies have been taken into consideration when a solution (e.g., transmission) is recommended in a regional plan.

*Distribution Planning:* Inconsistencies between LDC Distribution System Plans (DSP) and RIPs in some applications have been identified. The RPPAG therefore recommends that LDCs be required to identify where there is an inconsistency between the DSP and the RIP (or IRRP as it relates to non-wires alternative recommendations) submitted in their application and explain the reasons why – particularly where an investment in the DSP is different from the optimal (i.e., most cost effective) investment identified in the RIP.

*Municipal Planning:* Many municipalities tend to include aspirational goals (e.g., net zero) in their municipal energy plans (MEP) that lack the information needed by LDCs to reflect those aspirational goals in their load forecasts. The RPPAG is therefore recommending that a brief document be prepared that sets out the information that LDCs need from municipalities to increase the accuracy of their load forecasts (which determine regional needs). It would also increase process efficiency as some LDCs currently reach out to municipalities on an individual basis to obtain that information.

*Natural Gas Planning:* Enhance coordination between Natural Gas and Electricity Regional Planning through Enbridge's *targeted* participation in the Regional Planning processes to avoid planning for the same energy need and to also avoid unintended consequences between the two systems. For example, if Enbridge plans for non-pipe alternative (NPA) investments, such as electric powered heat-pumps, regional planning should be informed by incorporating the increased load growth, including informing Enbridge if the electricity grid can accommodate the additional load within the timelines that the NPA investment must be deployed. If electric grid investments are required, the associated costs and benefits should be provided to Enbridge so they can be taken into consideration. As referenced above, one of the triggers for this recommendation was the recent OEB Decision on Enbridge's IRP since it allows for NPA investments.

**7) Open Stakeholder Access to (IESO) Planning Information**

The RPPAG recommends that the IESO should continue to make planning information available to interested stakeholders – at a minimum, the planning information the IESO has committed to provide in the recent West of London pilot – to achieve the following outcomes:

- Increase public trust in the regional planning process; i.e., stakeholders have access to the same information / data that the IESO uses before planning decisions are made.
- Facilitate more meaningful stakeholder input during IESO IRRP stakeholder engagements *before* an application is filed with the OEB.

- Increase efficiency of the OEB regulatory process (i.e., fewer interrogatories) *after* the application is filed.

There is also support among all non-utility RPPAG members for a new IESO licence obligation by the end of 2022 to make additional planning information available to stakeholders that does not pose a system security risk to the IESO-controlled grid and/or is not confidential.[4] The IESO does not believe a licence obligation is necessary and prefers that its ongoing efforts in this area continue to develop under its own existing regional planning responsibilities, rather than a new OEB license obligation. While Hydro One also does not feel a licence obligation is necessary, Hydro One does believe this requirement should be formalized in the RPPAG Report setting out the regional planning process. On the other hand, LDC members of the RPPAG did not take a formal position. The IESO also does not believe that the data released for the West of London pilot should be the minimum standard for sharing information as there is insufficient experience to determine its universal applicability to all regions.

**8) Existing Option to Bypass IRRP Process: Proposed Approach to Address RPPAG Concerns**

Not undertaking an IRRP and going directly to a RIP (i.e., wires solution) has been an option since the regional planning process was implemented. The RPPAG has concerns related to bypassing the IRRP process given how the system has evolved since 2013 – a much greater emphasis on non-wire alternative (NWA) solutions (e.g., DERs) and the increased emphasis on meaningful stakeholder engagement. The RPPAG is therefore recommending criteria be established and documented in the RPPAG Report that sets out the regional planning process for transparency purposes, as that determination is currently based on IESO criteria.[5]

[4] Non-utility RPPAG members include: Association of Municipalities of Ontario (AMO), Association of Power Producers of Ontario (APPrO), Common Voice Northwest, Non-Wires Solution Group (NWSG), Pollution Probe, School Energy Coalition (SEC), Versorium Energy (DER developer).

[5] The IESO criteria has been included in various reports and stakeholder presentations.

**9) Potential Changes to CDM Guidelines to Eliminate Barriers**

Facilitate the implementation of the optimal solution identified through the regional planning process where it involves CDM by eliminating barriers as follows:

- Expand the scope to include cost effective deferral of all types of wires solutions including transmission infrastructure (i.e., no longer limit to distribution infrastructure deferral).

- Allow multiple LDCs to jointly apply under the CDM Guidelines and require them to do so where the conservation efforts of all those LDCs are required to meet a regional need and the transmission infrastructure. This approach should facilitate the appropriate determination of cost responsibility, which the RPPAG recommends be aligned with the current approach that applies to wires as set out in the OEB's Transmission System Code (i.e., based on proportional benefit).

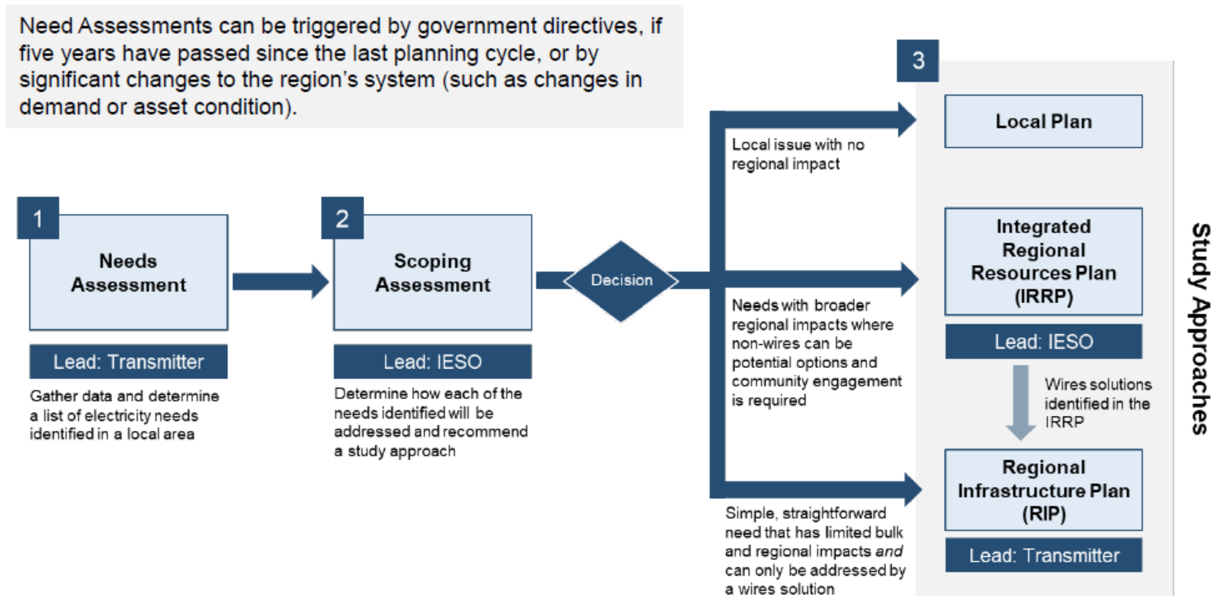
The RPPAG also recommends another review of the CDM Guideline approach to cost responsibility once the OEB's FEI initiative completes its work related to assessing the value of DERs relative to traditional wires investments.

This recommendation recognizes technology options are rapidly evolving and the benefits are not necessarily limited to the distribution system. Enabling the adoption of new cost effective technologies that benefit the transmission system through the removal of those barriers is therefore important.

Appendix C includes a table that consolidates and summarizes the RPPAG's recommendations in more detail.

## 2. Current Regional Planning Process – Stages, Roles & Timelines

For context, the chart and related discussion below explains the four key stages in the regional planning process and the entity that leads each of the stages – IESO or Lead Transmitter (typically Hydro One). The maximum amount of time set out in the OEB's regulatory instruments – Transmission System Code (TSC) and IESO licence – to complete each stage is also identified.




Each region has a Technical Working Group (TWG) comprised of the IESO, the lead transmitter and the applicable LDCs in the region. It is important to note that all members of the TWG are involved in the decision making at each of the four stages of the regional planning process.

The process begins with a **Needs Assessment** which is led by the transmitter. The Needs Assessment is undertaken to determine if there are needs in the region that must be addressed and whether a regional plan is required. That determination is primarily based on the load forecasts provided by LDCs to the lead transmitter. Another key input is the identification of the major transmission assets that are forecast to reach their end of life (EOL) in the near term. Under the TSC, the lead transmitter has **60 days** to complete this stage.

- If needs are identified and *regional coordination* is required, a Scoping Assessment is undertaken.
- If a need is identified but *regional coordination* is <u>not</u> required (e.g., one LDC has a need for a station upgrade at EOL), a **Local Planning** process is undertaken involving the lead transmitter and the LDC.
- If no needs are identified in a region, the regional planning process ends for the region and another Needs Assessment will be undertaken in five years.

The **Scoping Assessment** is led by the IESO and the primary purpose is to determine which type of regional planning process should be carried out; that is, undertake an

IRRP (assess both non-wires and wires) or go directly to a RIP (assess wires only). To date, an IRRP has been carried out in all but one case where regional planning was required. The Scoping Assessment includes a stakeholder engagement component. Under the IESO's licence, this stage must be completed in **90 days**.

An **Integrated Regional Resource Planning (IRRP)** process is led by the IESO to determine the appropriate mix of non-wire and wires solutions to meet the needs in a region. The IRRP process also includes a stakeholder engagement component. Under the IESO's licence, this stage is intended to be completed in **18 months**, but if additional time is required, up to a maximum of 24 months.[6]

A **Regional Infrastructure Planning (RIP)** process is led by the lead transmitter to carry out a more detailed assessment of the wires solutions recommended in the IRRP. A region may also have one or more Local Plans. The results of any Local Plans in the region are incorporated in the RIP. The RIP is therefore the only document in the process that consolidates all the wires solutions in a region. Under the TSC, this stage must be completed in **6 months**.

# 3. Detailed Discussion of RPPAG Recommendations – IESO Related

## Standardize & Streamline Load Forecast Development

*Standardized Load Forecast*

The IESO Final Report recommended increased standardization of load forecasts that are used in the regional planning process. The RPPAG agrees with the IESO and is therefore recommending development of a Guideline for LDCs, Hydro One and the IESO to use in preparing load forecasts to ensure greater consistency (e.g., assumptions) in determining regional needs and to avoid the current inefficiency of the IESO standardizing the information received from LDCs when aggregating the LDC forecasts at the regional level.

A Load Forecast subgroup of the RPPAG is currently developing that Load Forecast Guideline for implementation purposes. Once the subgroup has completed its work on a final draft Guideline, it will be brought to the RPPAG for review. The Guideline would then be added as an appendix to the RPPAG Report setting out the regional planning process once it is finalized.

[6] The IESO must notify the OEB if the additional six months is required.

The RPPAG discussed the development of a template that the IESO also recommended to better ensure that LDCs use the agreed upon assumptions. While the RPPAG agrees a template would be beneficial, the RPPAG believes it is best to hold off on creating one until experience is gained using the Load Forecast Guideline because the template will be based on the Guideline and there may be a need to revise the Guideline post implementation. The RPPAG is therefore recommending to defer the development of a template to a later date.

The RPPAG expects that the standardized demand forecast that will be used for regional planning purposes will typically not also be used as the load forecast for LDC rate application purposes for various reasons. For example, a considerable time difference between filing of the rate application and the regional plan being finalized may affect the forecast. The RPPAG is noting this because the question has arisen a number of times within RPPAG meetings and other forums (e.g., FEI Working Group meeting).

*<u>Assessment of Load Forecast Options</u>*

The IESO's Final Report also recommended that the RPPAG consider two load forecast options:

- Option 1 – Occurs only once (same comprehensive 20-year forecast used for all four stages to avoid duplication of work).

- Option 2 – Occurs twice (10-year higher level forecast for Needs Assessment and 20-year comprehensive forecast for IRRP & RIP to evaluate options).

The RPPAG is recommending Option 2, with a 10-year higher level forecast prepared first for the Needs Assessment (must be done by all LDCs in all 21 regions), and a 20-year comprehensive forecast on an as needed basis (i.e., only regions where an IRRP is required). The primary reason for recommending Option 2 is it avoids an inefficiency associated with Option 1; that is, a 20-year detailed forecast would be prepared by all LDCs in the province whether regional planning is needed or not. Since an IRRP is typically required for only about 50% of the 21 regions, LDCs in about 50% of the regions would be investing substantial additional resources and there will be little or no benefit because it would not be used beyond the first stage of the process. The RPPAG therefore expects the costs would exceed the benefits if Option 1 was adopted (relative to the preferred Option 2).

In summary, the RPPAG is recommending the following:

1. A Load Forecast Guideline to standardize the load forecasts provided by LDCs to the lead transmitter and the IESO.

2. The load forecast option that entails a 10-year higher level forecast for the Needs Assessment and a more detailed 20-year comprehensive load forecast for the IRRP and RIP processes to evaluate specific options to meet the needs.

## Clarify Scope between IRRP and RIP – Wires investments

As discussed above, an IRRP process is led by the IESO to determine the appropriate mix of solutions (CDM, DERs, wires) to meet the regional needs. A RIP process is then led by the lead transmitter (i.e., Hydro One) to further assess the wires options recommended in the IRRP.

The RPPAG agrees with the IESO recommendation to clarify the scope of work that is undertaken by the IESO in the IRRP process and the lead transmitter in the RIP process.

The RPPAG therefore recommends making the scope of the RIP and the IRRP more clearly defined in the RPPAG Report that sets out the regional planning process to avoid duplication of efforts as follows:

- The load forecast used in the IRRP process should also be used in the RIP process unless there is a *material change.*

- The level of detail in an IRRP on wires solutions should be limited to the level required to compare the wires and non-wire options.

*Material Change – Need for IESO Licence Amendment*

As discussed above, the RPPAG's recommended approach hinges on whether a *material change* occurs during the RIP process. The question therefore arises as to what constitutes a material change within this context. The RPPAG does not believe material change should be defined for this purpose because it will depend on the circumstances in the region, and the regions differ substantially across the province (e.g., northern Ontario vs. southern Ontario). The RPPAG believes, where the members of the TWG in a region (i.e., IESO, Hydro One and applicable LDCs) agree a material change has occurred, that should be sufficient; that said, the reasoning should be documented for transparency.

In addressing this recommendation, the RPPAG notes it was identified that a material change during the RIP process has occurred a couple times in the past which necessitated a return to the IRRP to ascertain if wires were still the most cost effective solution. The RPPAG also notes that this raises an issue; that is, this scenario involving a return to the IRRP process from a RIP process was not contemplated when the regional planning process was initially established. It is also therefore not reflected in the OEB's regulatory instruments.

The RPPAG is therefore recommending that this scenario be formalized for transparency purposes through an update to the RPPAG Report that sets out the regional planning process as follows.

- There are often sub-regions, within the broader defined region, where a regional plan is required to meet system needs. Work on the RIP would continue to address the sub-regions not affected by the material change to ensure the six-month timeline set out in the TSC is met.

- The IESO would assess the impacted sub-region to ascertain if a non-wires solution is a viable option. If so, the RPPAG expects it would take more than six months to complete an expedited IRRP.

- The RIP would therefore be updated once the IESO completes the work on the expedited IRRP and an Addendum would be added to the RIP (i.e., letter from the IESO).

Since the IESO's licence does not contemplate this scenario, the RPPAG considered two options to recognize and formalize it:

1. The IESO seek an exemption from the OEB; or
2. The OEB amend the IESO's licence.

The RPPAG recommends an IESO licence amendment for a number of reasons. An IESO exemption request to the OEB would delay the regional planning process. It would also add administrative burden for both the OEB and the IESO (i.e., inefficient). It is also outside the IESO's control, and the reassessment of the previously recommended wires solution is a necessary step to achieve the OEB's goal of implementing the optimal solution. For that reason, the RPPAG believes the OEB would always grant an exemption if the first option was adopted. It would therefore be unnecessary additional administrative burden.

*Formal sign-off by each Technical Working Group (TWG) member*

The IESO's Final Report suggested that all TWG members be required to sign off on the regional plan. The RPPAG does not support this IESO suggestion as the RPPAG concluded there would be unintended consequences, including delays in the process (i.e., reduced process efficiency) because corporate approval among the entities involved would likely be required before each entity formally signed off. In addition, LDCs would be signing off on solutions that do not affect them and/or they do not fully understand (e.g., transmission upgrade to meet IESO ORTAC reliability criteria, etc.).

The RPPAG is recommending an alternative approach which would involve formalizing the process where any TWG member disagrees with the recommended solution in an IRRP and/or RIP. That would be achieved by formally documenting their dissent and providing reasons for not supporting the recommended solution. Under this approach, it would be assumed that all TWG members support the recommended solution if they did not formally dissent. During the RPPAG discussions, the IESO agreed that formal sign off should not be required and supports this alternative approach.

In summary, the RPPAG is recommending the following:

1. Make the scope of the RIP and the IRRP more clearly defined in the RPPAG Report that sets out the regional planning process to avoid duplication of efforts.

2. Formalize a process that has occurred but was not contemplated when the current regional planning process was developed involving a *material change* during the RIP process that triggers a return to the IRRP process.

    a. This would require an update to the RPPAG Report that sets out the regional planning process and an amendment to the IESO's licence to recognize this scenario.

3. Formalize that, if any TWG member disagrees with recommended solution in an IRRP and/or RIP, the dissent should be formally documented with reasons for not supporting that solution.

## Better Consideration of Cost Responsibility in Regional Planning Process

*<u>OEB staff Plain Language Document</u>*

In the IESO's Final Report, it was identified that there was a lack of common understanding of the OEB's cost responsibility rules, particularly among smaller LDCs, and the IESO recommended that steps be taken to address that issue since LDCs are members of the TWG in each region and are therefore involved in recommending the solutions to meet the regional needs.

The RPPAG notes it is quite understandable that there is a lack of common understanding of the OEB's cost responsibility rules because they are set out in many documents including the TSC, the DSC, Bulletins, CDM Guidelines, etc. In addition, some relatively substantive amendments were recently made to the TSC and DSC, and the CDM Guidelines are in the process of being amended.

The RPPAG is therefore recommending that OEB staff prepare a plain language document that provides a consolidated explanation of the key cost responsibility rules related to regional planning to ensure there is a common and correct understanding of the rules so that all members of each regional TWG are better informed when they recommend solutions (i.e., understand cost consequences). This plain language document should be periodically updated to reflect any material subsequent changes to the rules in the underlying cost responsibility documents. The RPPAG notes that, while LDCs are the trigger for this recommendation that would consolidate the discussion of all the key rules in one easy to understand document, commercial & industrial (C&I) customers would also benefit, particularly those that are starting up operations in Ontario for the first time.

*<u>Cost Responsibility Guidance – Local Preferences</u>*

The IESO also indicated in its Final Report that there was a need for cost responsibility guidance where communities want a *premium* solution that reflects "local preferences". In other words, a solution that is *higher cost* than the *optimal* (i.e., most cost effective) solution identified in a regional plan.

The RPPAG notes that the OEB already provided such guidance but it was in a relatively dated document – 2017 Notice of Proposal to Amend a Code – that few, if any, stakeholders would be aware of.[7] The RPPAG believes that this guidance is quite

[7] The OEB guidance is provided on page 34-35 of the Notice.

important and will become increasingly important in the future (i.e., growth in DERs, consumers becoming more engaged, etc.).

The RPPAG is therefore recommending a new OEB Bulletin be created to include that guidance. Incorporating it in a new and focused document would result in stakeholders becoming aware of it. The RPPAG wishes to clarify that we are not recommending any changes to the guidance, as the RPPAG agrees it is appropriate that ratepayers pay an amount of the cost through rates that is equivalent to the *optimal* solution determined in the regional planning process and any premium be recovered through other means (e.g., paid by LDC shareholder and recovered though property taxes). The RPPAG recommends that this new Bulletin make it clear that guidance was provided by the OEB (i.e., not OEB staff) by quoting the applicable guidance in the 2017 Notice.[8]

The RPPAG also recommends a review of that Bulletin be undertaken once the OEB's FEI initiative reaches a conclusion on assessing the value of DERs relative to traditional wires investments, as that may change how the *optimal* solution is defined.

*OEB Bulletin Update*

The RPPAG is also recommending that the OEB update its September 2006 Bulletin that explains the circumstances under which transmission Network upgrade costs should be paid for by specific customers; such costs are typically socialized (i.e., recovered from all Ontario consumers). There is a lack of awareness of that Bulletin since it was issued in 2006 (i.e., over 15 years ago).

An update to the Bulletin would not only increase awareness of it. An update would also provide an opportunity to increase clarity. For example, there is no reference in the Bulletin to the related TSC provision (i.e., section 6.3.5). An update would also provide an opportunity to reflect the changes made to the TSC over the past 15 years. As noted, such costs are typically socialized and, if not, the RPPAG believes impacted customers should not learn of that at the time the regional plan is implemented.

*Timing of Cost Responsibility Consideration*

The RPPAG is also recommending that cost responsibility be considered in the regional planning process going forward. However, it should only be discussed at a high level among TWG members – not detailed cost estimates in a regional plan – as cost

[8] This would be similar to OEB staff letters that have been issued to all the applicable entities (i.e., all regulated LDCs, IESO, etc.) describing changes made by the Government to Reg, 429/04 (Global Adjustment Regulation), rather than providing new OEB staff guidance.

responsibility considerations should not result in a deviation from the optimal (i.e., most cost effective) solution, and further, are not the mandate of the TWG members.

In summary, the RPPAG is recommending the following:

1. A plain language document be prepared by OEB staff that consolidates and explains the key cost responsibility rules related to regional planning.

2. A new OEB Bulletin be created that provides cost responsibility guidance where communities elect a *premium* solution (i.e., higher cost than the optimal solution) that reflects *local preferences* (e.g., DER, rather than wires).

    a. Undertake a review of that Bulletin once the OEB's FEI initiative reaches a conclusion on assessing the value of DERs relative to traditional wires investments, as that may change how the optimal solution is defined.

3. An update to the OEB's September 2006 Bulletin that explains the circumstances under which transmission Network upgrade costs should be paid for by a specific customer to increase awareness and clarity.

4. Cost responsibility be addressed in the regional planning process but in a manner that does not result in a deviation from the optimal (i.e., most cost effective) solution.

## Better Address End-of-Life (EOL) Asset Replacement in regional planning process

Before discussing the recommendations related to this issue, the RPPAG believes it is important to explain the difference between two different terms that some appear to believe mean the same thing, but they do have different meanings.

*End of Life (EOL)* – The EOL of an asset involves assessing a number of factors, including the physical condition of the asset, and it is a *determination* of when an asset will need to be replaced by the asset owner (e.g., transmitter) based on those factors. The outlook is typically no longer than 10 years.

*Expected Service Life (ESL)* – The ESL of an asset informs investment decisions by providing a long-term outlook to *inform* when an asset is expected to reach its

EOL and need to be replaced. It does not involve an assessment of the physical condition of an asset. Rather, it focuses primarily on the age of the asset. The outlook is typically 20 years or longer.[9]

*Expected Service Life (ESL)*

Currently, only the transmission asset owners (TAOs – transmitters & applicable LDCs) have access to information related to the ESL of their assets. The IESO expressed the view in its Final Report that this ESL information should be shared because it is important for long term planning purposes. The IESO's Final Report therefore recommended formalizing a process where all TAOs develop a long list of facilities with the ESL for categories of major transmission (i.e., high-voltage) assets – transformers, circuit breakers, overhead lines, and underground cables – since these categories present the highest-value opportunities for non-like-for-like replacements. The list would be based on a 20-year outlook, it would be provided to the IESO, and it would be updated annually.

The RPPAG agrees that such information is important for long term planning purposes and should be shared by asset owners since it informs when assets will reach EOL. However, the RPPAG is also recommending some deviations from the IESO's proposed approach including the following:

- Instead of providing a list of facilities which have reached or exceeded their ESL, the transmitter would provide Asset Demographic information for major transmission facilities over 20 years in age. This will improve the efficiency of providing the information and serve the same intent in providing a long-term view of asset replacement needs.
- Not limit providing Asset Demographic information to only the IESO. Instead, it should be made available to interested stakeholders on a basis that is similar in nature to the interconnected New York ISO (NYISO) but less stringent given the nature of the Asset Demographic information relative to critical information being shared by NYISO. It should also be modified as necessary to reflect Ontario.
- Remove the 20-year time limit, since it is no longer needed due to the change in the nature of information to be provided (i.e., simplified to age as opposed to a list of facilities past their ESL).
- For efficiency purposes, since Hydro One owns most of the major transmission assets in Ontario, focus on collecting the Asset Demographic information from

[9] The ESL is defined as the average time duration in years that an asset can be expected to operate under normal system conditions and is determined by considering manufacturer guidelines and the transmitter's historical asset retirement data.

only Hydro One at the outset – not all TAOs – to get the process right and ascertain the value of this information before imposing the sharing of such information on all TAOs.

- Reduce the frequency of updates to the IESO from annually to every five years to better balance the value of updating the information with the cost of providing it. Since the information being provided consists primarily of asset age, the change would be immaterial on an annual basis.
- A template has been developed by the RPPAG to ensure the IESO would receive the information in a consistent manner.

The RPPAG notes that, since the ESL of these assets can exceed 40 years, Hydro One agreed to provide this Asset Demographic information related to assets over 20 years old to the IESO during the RPPAG meetings. It therefore appears that implementation of this recommendation may not require any changes to the OEB regulatory instruments.

This longer-term outlook that informs when assets will reach EOL would provide more lead time to evaluate alternatives to like-for-like replacements including non-wire alternatives (NWA), such as DERs, as well as ‘right sizing’ where the replacement involves another transmission asset.

*End of Life (EOL)*

The RPPAG agrees with the IESO Final Report recommendation that all TAOs, including the applicable LDCs (i.e., not only Hydro One), provide a 10-year outlook related to the end-of-life (EOL) of major transmission assets. The IESO also recommended this information be updated annually. Unlike the ESL-related information, the RPPAG agrees that all TAOs should provide EOL information because it is a key input in the Needs Assessment.

Similar to the Asset Demographic information, the RPPAG is recommending some deviations from the IESO’s recommended approach.

- Reduce the frequency of updates so the process is more efficient and less of burden for all TAOs. Instead of annually, TAOs will provide their 10-year outlook related to EOL of major transmission assets as part of the regional planning process, during the Needs Assessment, which is typically every five years.
- On a go-forward basis, the IESO will consolidate this EOL information received from all the TAOs into a single list on an annual basis to be made available to all

interested stakeholders. Doing so is much more efficient than stakeholders reviewing each Needs Assessment report for all 21 regions.
- Similar to the ESL information discussed above, a template has been developed by the RPPAG to ensure the information would be provided consistently to the IESO by all TAOs.

The RPPAG is also recommending that the OEB create a mechanism to ensure all TAOs provide that EOL information to the IESO, since the IESO does not have a similar mechanism that could be applied to all the applicable LDCs. The RPPAG notes the OEB is also able to enforce compliance to ensure this important planning information is provided by the TAOs, while the IESO cannot.[10]

Two options were discussed by the RPPAG for the OEB's consideration: (1) Amend all transmitter and LDC licenses; or (2) Amend the applicable Codes (TSC and DSC). The RPPAG believes amending the Codes would be more efficient and more appropriate since they include all the existing regulatory obligations related to regional planning that apply to LDCs and transmitters.

In summary, the RPPAG is recommending the following:

1. A formal process be established that involves Hydro One providing Asset Demographic (i.e., asset age) information to the IESO every five years for categories of major transmission assets that are over 20 years old to provide an indication of their ESL.

    a. The IESO provide access to that Asset Demographic information to all interested stakeholders via a platform that is similar to the NYISO's CEII process, but less stringent to reflect the relative nature of the information and modified, as appropriate, to reflect Ontario.

2. All transmission asset owners (TAOs), including the applicable LDCs, provide a 10-year outlook related to the EOL of major transmission assets to the IESO during the Needs Assessment (i.e., typically every five years).

[10] While not within the mandate of the RPPAG, the approach to incorporating EOL information into the Bulk Planning process was also discussed, with Hydro One agreeing to provide the EOL information for major bulk facilities to the IESO during Issues Identification. The RPPAG has left the implementation of this recommendation to the IESO as part of its Bulk Planning process.

a. The OEB amend the DSC and TSC to require providing that EOL information because it is critical to the regional planning process and it involves a number of LDCs.

b. The IESO will consolidate EOL information received from the TAOs into a single list, on an annual basis, and make the list available to all interested stakeholders; particularly those in the regional planning process.

# 4. Detailed Discussion of "Other" Additional RPPAG Recommendations

## General Education on Regional Planning Process to Stakeholders

The RPPAG recommends that general education sessions be conducted with stakeholders that play a role in the regional planning process. Some have a direct role (e.g., LDCs) as participants in the process, while others have an indirect role (e.g., municipalities). The RPPAG acknowledges there are already stakeholder engagement sessions that occur on a relatively frequent basis. However, they are region specific and focus primarily on the needs and potential solutions to meet the needs related to the development of specific plans.

General education sessions related to regional planning have not been undertaken since the process was implemented in 2013. Since then, staff at LDCs, for example, have changed and there has been growth in the scope of stakeholders involved in the process (e.g., DER developers). Some municipalities and other stakeholders have also indicated that they do not fully understand the current process.

The RPPAG believes such general education sessions should not be undertaken by any one single entity. Instead, it should be a coordinated effort by staff from the OEB and the two entities that lead the various stages in the regional planning process – IESO and Hydro One – like it was done in 2013. It would likely also be beneficial to have some LDC involvement depending on the audience; specifically, one or more LDCs that have participated in all stages of the regional planning process.

The RPPAG believes a general education initiative would have the following beneficial outcomes:

- A better understanding of how the process works and the information that is required / available among stakeholders should result in a more efficient and effective regional planning process.
- It would provide an opportunity to inform all LDCs, other transmitters and interested stakeholders of the modifications to the process resulting from the RPPAG's recommended changes that are endorsed by the OEB, including any changes that the OEB decides to make to its regulatory instruments (e.g., TSC, DSC).
- It would also provide an opportunity to inform stakeholders of the new documents – Load Forecast Guideline, OEB staff plain language document on Cost Responsibility, any new / updated Bulletins that the OEB supports proceeding with, etc.
- There has also been an increase in the use of other types of planning processes (e.g., Community Energy Planning) and education on the linkages with the regional planning process should be beneficial, particularly for the purpose of improving coordination between the processes.

The RPPAG believes the primary educational tool should be webinars with the related presentations and recordings posted. Unlike educational documents, webinars are interactive and therefore provide an opportunity for questions and answers. Posting presentations and recordings would provide a resource for those who become involved in the regional planning process in the future (e.g., LDC staff retire, and new staff replace them).

In summary, the RPPAG is recommending the following:

1. General education sessions related to the regional planning process be conducted involving stakeholders that play a role in the process.

2. Those sessions be a coordinated effort involving staff from the OEB and the two entities that lead the stages in the regional planning process – IESO and Hydro One.

3. Webinars be used as the primary educational tool (with the related presentations and recordings posted, for future reference, until future material changes are made to the regional planning process).

## Holistic Coordination of Planning Processes – Regional, Bulk, Distribution, Natural Gas, Municipal

*Regional* planning is key in Ontario due to the large number of LDCs. As indicated in the chart below, it also has linkages with *bulk* system planning (which focuses on addressing provincial electricity needs) and *distribution* planning (which addresses needs at the local community level). Due to those linkages, coordination between those planning processes is important in ensuring the optimal solutions are implemented to meet the needs. *Municipal* planning information is also a key input in the regional planning process in determining the needs that must be met. *Natural gas* system planning is also evolving with the adoption of Enbridge's IRP and coordination with regional planning should be enhanced. This recommendation focuses on enhancing coordination among those four types of planning.[11]


*<u>Bulk Planning</u>*

The RPPAG notes that when the OEB is asked to approve a transmission investment in a Leave to Construct (LTC) application, there are often other investments also being planned that have linkages and interdependencies which are set out in regional and/or bulk plans (sometimes multiple bulk plans).

To make a more informed decision, the RPPAG believes that OEB Panels deciding on the LTC application should see all the interdependent transmission investments in a "holistic" manner – from both Bulk Plans & Regional Plans. Rather than the typical approach of reviewing individual investments in "isolation" of the "bigger picture".

[11] The IESO's Final Report (p. 22-23) discussed "Integration and Coordination with Related Processes" which focused on processes within the electricity sector, including the IESO's procurement mechanisms. The RPPAG felt the need for coordination was broader in nature (i.e., beyond the electricity sector). For example, most of the RPPAG discussions focused on improving coordination with natural gas system planning and the municipal planning process. The RPPAG did not delve into matters such as coordination with IESO procurement processes.

The RPPAG is therefore recommending all related transmission (and non-wire) solutions that have been recommended or are being planned in multiple contiguous regions be consolidated in a single document prepared by the IESO (e.g., letter) that summarizes all the planned investments in various related bulk and regional plans (including the estimated individual and aggregate costs, where available, with appropriate caveats related to the accuracy of the cost estimates). The RPPAG notes it would be like an Executive Summary that references all the applicable plans.

This IESO document would identify the independencies. For example, where the OEB is considering “x” transmission investment in an LTC application, the OEB should also be aware of “y” and “z” transmission solutions – to be proposed in future LTC applications – since they are expected to be required to meet all the multi-regional needs and/or they will be required to fully realize the benefits from “x” transmission investment in the current LTC application.

This recommended document should also be beneficial to intervenors in the applicable LTC proceeding. It should also increase efficiency of the OEB regulatory process as there are often interrogatories requesting such information.

A good example of the type of document that the RPPAG is recommending is a presentation that was prepared by the IESO for the West of London area that is posted on the IESO’s Windsor-Essex regional planning web page. It summarizes each bulk plan and the Windsor-Essex IRRP, and proceeds to discuss the interdependencies.

This recommendation is consistent with the views expressed by an OEB Panel in its Decision & Order related to a case involving the St. Laurent gas project (EB-2019-0006).[12] The OEB Panel noted the following:

> “The interrogatory responses … have added clarity and assisted in the OEB’s understanding of the Proposed Project … the OEB has concerns about granting stand-alone approval for one part of a multi-phase, multi-year and multiple location project. Whenever possible, the OEB prefers to consider the overall plan for supply to an area when assessing each project.
>
> Despite the OEB’s dissatisfaction that the current application was filed in isolation from the overall replacement … the OEB accepts that it is in the public interest for this project to proceed at this time.”

[12] The St. Laurent project was part of an Enbridge Gas case.

> The OEB expects that approvals for the remaining multi-phases of the … Project will be dealt with on a comprehensive basis….”.

The RPPAG notes that the IESO members of the group acknowledged the importance of the document recommended above and support producing it. That said, there was some debate *when* this document should be produced – at the time each IRRP is completed versus at the time the LTC application is filed. The majority of RPPAG members supported when the application is filed with the OEB because the application would then include the most recent information.

The RPPAG proposes that the recommendation discussed above be implemented through changes to the OEB’s Filing Requirements for LTC Applications (i.e., transmitter would be required to request this document from the IESO to include as part of its LTC application to the OEB).

*Distribution Planning*

The OEB requires that a distributor file both a Distribution System Plan (DSP) and a RIP as part of its rate application to the OEB. However, inconsistencies between the DSPs and RIPs in some LDC applications have been identified.

The RPPAG believes it is important to ensure an LDC’s DSP submitted in a rate application is consistent with the RIP – unless there is a good reason for any differences – given both are planning documents that are intended to support capital investments the LDC is proposing to make.

It is also important that all the documents in the overall electricity planning process be aligned in relation to the solutions that are being proposed to meet the needs. As discussed above, there are often interdependences between the solutions and linkages among the various planning processes.

The RPPAG therefore recommends LDCs should be required to identify if and where there is an inconsistency between their DSP and the RIP, and explain the reasons why, particularly where a proposed investment in their DSP is different from the recommended optimal investment in the RIP. The LDC would have been a member of the Technical Working Group that recommended the optimal investment identified in the RIP. This recommendation could be implemented through changes to the OEB’s Fling Requirements for LDC rate applications.

*Municipal Planning*

The RPPAG notes that municipal planning documents are very important within the context of regional planning because information from them is incorporated in the load forecasts provided by the LDCs to the lead transmitter as part of the Needs Assessment process, and to the IESO as part of the IRRP process. The forecasts are therefore the primary determinant of the needs that must be addressed within most regions.[13] If the needs are not appropriately identified, there is a high probability that the optimal investment will not be made since the determination of the investment is based on the need.

An issue that arises is that, while some municipalities prepare their municipal energy plan (MEP) based on information that informs how the MEP goals would be achieved, other municipalities do not. Instead, they tend to include aspirational goals (e.g., net zero) in their MEP which LDCs cannot translate into their load forecasts that are used to identify regional needs.

The RPPAG acknowledges that the OEB does not have the authority to directly address this issue (i.e., require municipalities to provide the necessary information to LDCs); however, alignment of regional planning with municipal energy planning is essential to achieve a consistent and cost effective approach to meet Ontario consumer and community energy needs.

The RPPAG is therefore recommending that this be a component of the RPPAG's "General Education on Regional Planning" recommendation. For example, coordinate with the Association of Municipalities of Ontario (AMO) and their affiliated regional groups to have a targeted session focused on their member municipalities.[14]

In addition, where there is insufficient information in MEPs, some LDCs reach out to the applicable municipalities to obtain the information they require. In doing so, they provide a similar list of the required information to each applicable municipality and/or the consultant they have retained to assist them on their MEP. This can be a resource intensive process for LDCs in dealing with municipalities individually.

The RPPAG is therefore recommending a brief document (i.e., two-pager) be prepared that includes a list of information that LDCs need from municipalities to increase

[13] Northwest Ontario is unique because mining development outside of municipal boundaries tends to be the primary driver.
[14] Affiliated regional groups of AMO include the Northwestern Ontario Municipal Association (NOMA) and the Federation of Northern Ontario Municipalities (FONOM).

planning process efficiency and consistency, and therefore improve the accuracy of their load forecasts. The document would also explain why an accurate load forecast is critical and therefore why providing the information is important; that is, the load forecast is a primary determinant of the investment that is ultimately made, and *local* ratepayers will ultimately pay for. This document would be provided to all municipalities and the consultants that they retain. It would therefore be done once and consistently across province, rather than repeatedly by only some LDCs on a one-off basis. The longer-term desired outcome of the RPPAG is that municipalities would begin to dedicate a section in their MEPs to include this information. The RPPAG has prepared a draft of this document that would be provided to municipalities.

*Natural Gas Planning*

During the RPPAG's discussions, one IESO IRRP engagement process was identified where Enbridge had material involvement. It was the unique Windsor-Essex region where unprecedented greenhouse load growth has driven the need for new infrastructure of all types that extended beyond electricity and natural gas (e.g., water & sewage). Coordination between the IESO and Enbridge was good in that case. That said, the need for coordination in that instance may not be indicative of why greater coordination may be needed in the future, particularly as the energy system continues to evolve.

The recent OEB Decision on Enbridge's Integrated Resource Plan (IRP) is a further step in that evolution, since Enbridge is no longer limited to pipeline-related facility investments and will be making non-pipe alternative (NPA) investments for the first time. This comes at a time when electric utilities are expected to place a growing emphasis on non-wire alternative (NWA) investments, such as DERs, to meet regional and local needs. Unlike the major infrastructure build in the Windsor-Essex region, NPA and NWA investments are relatively minor in nature (i.e., not obvious). The RPPAG therefore anticipates the need for improved coordination between Natural Gas Planning and Electricity Regional Planning may increase in the future for reasons that also includes the following:

- To avoid planning for the same energy need. For example, the IESO and Enbridge assume different levels of electrification resulting in over- or under-planning.

- To avoid unintended consequences between the two systems. For example, if Enbridge plans for NPA investments using electric powered heat pumps, regional planning should be informed and incorporate the increased load growth, including informing Enbridge if the electricity grid can accommodate the additional load within the timelines that the NPA investment must be deployed. If electric grid investments are required, the associated costs and benefits should be provided to Enbridge so they can be taken into consideration.[15]

The RPPAG expects it will take some time for Enbridge's IRP to mature. The RPPAG therefore believes that the level of co-ordination/data sharing needed, at this time, between Natural Gas Planning and Electricity Regional Planning can be achieved by Enbridge participating in the existing Regional Planning processes. There are currently two key pathways for stakeholders to provide input and feedback.

i. The first is through the outreach and public engagements that the IESO completes. Engagement activities during the IRRP process generally consist of targeted outreach and public webinars, occurring at key milestones (i.e., demand forecast, needs, potential solutions, draft recommendations). In terms of Enbridge, the RPPAG believes the focus should be on "targeted" outreach for reasons including the one discussed below.

ii. The second way for Enbridge to provide input is via the LDC, where it relates to demand growth that would be supplied by the LDC, given the LDC's role in developing the demand forecast that underpins the IRRP.[16]

The RPPAG does not believe Enbridge should be treated as a *typical* stakeholder with a *private interest* (e.g., storage developer, consultant, etc.) in such engagement processes. The RPPAG believes the approach to these coordination efforts should be as efficient as possible. A key reason the RPPAG holds this belief is Enbridge is a rate regulated entity. As a result, all the costs Enbridge incurs to participate in such engagement processes are borne by Ontario ratepayers and efforts should be made to minimize those costs. In addition, the goal of this coordination differs from many stakeholders as the focus is the *public interest* -- avoid investments that have negative (e.g., unintended) consequences for electricity and natural gas consumers.

To that end, the RPPAG is recommending the following actions be taken to improve the efficiency and effectiveness of Enbridge's participation in Regional Planning processes, such as IESO stakeholder engagements, through a *targeted* approach including:

[15] This would exclude NPAs that do not have a material impact on the electricity grid.
[16] Enbridge can also develop processes for IESO and LDCs to provide similar input into gas IRP plans. Enbridge's three component stakeholder engagement plan that was accepted by the OEB in its Decision allows for IESO and LDC stakeholder input at the Component 2 (regional engagement) and the Component 3 (geotargeted engagement) stages.

i. Meetings between IESO and Enbridge to improve the understanding of each other's planning processes, and to ensure that an efficient and effective process exists for keeping Enbridge informed of when regional planning in a particular region begins. The intent is also to keep Enbridge informed of when a Scoping Assessment will be initiated in a region since that is the first stage in the Regional Planning process where engagement occurs. This will avoid the inefficiencies of an approach that would require Enbridge to expend resources on monitoring all 21 regions across Ontario, particularly since only about 50% of the regions typically require regional planning (i.e., IRRP).

ii. Meetings between Enbridge and LDCs to ensure that Enbridge understands how to provide input into the LDC's load forecast, which informs the identification of needs in regional planning. The RPPAG believes it would be inefficient for Enbridge to interact with each of the 60+ LDCs on an individual basis. A more efficient approach would be for Enbridge to meet with the applicable regional TWG – which includes all the LDCs within a region – in those regions where regional planning is required.[17]

In the *future*, the RPPAG believes further coordination between the two planning processes may be *required* if one of more of the following occur:

i. Enbridge were to receive approval from the OEB to invest in electricity NWA solutions – like electricity LDCs – in a future IRP generation. The RPPAG believes it is the nature of the investment that matters (i.e., both electricity related) – not the nature of the utility.
ii. Enbridge increases its use of electricity-based solutions (such as electric heat pumps) to address constraints on their system.
iii. Policy direction is received requiring the integration of gas and electricity needs when assessing energy options, which could be an outcome of the Government's work to update Ontario's long-term energy planning (LTEP) framework.

If the OEB concludes, in the future, there is a need to *ensure* coordination between electricity regional planning and natural gas planning, the RPPAG recommends that OEB take an approach that is similar to the current requirements in relation to the IESO, LDCs and transmitters in the regional planning process. In other words, changes to the OEB's regulatory instruments to include obligations. For example, the OEB could develop a licence condition under IESO's Regional Planning Obligations to work in

[17] The Working Group being established by the OEB in the future to address matters related to Enbridge's IRP may also provide an opportunity to enhance coordination.

consultation with Enbridge. Since Enbridge is not licensed by the OEB, working in consultation with IESO could be required through a condition of approval of a future IRP application.

In summary, the RPPAG is recommending the following to achieve a more a holistic approach to electricity planning in Ontario and improved coordination of other key planning processes with the regional planning process:

1. ***Bulk Planning:*** When the OEB is asked to approve a transmission investment in an LTC application, the IESO prepare a document that summarizes all the other recommended and planned transmission (and non-wire) investments that are set out in regional and/or bulk plans that have linkages and interdependencies. Such recommended investments, or those under consideration as part of an ongoing planning process, would typically span multiple contiguous regions. The IESO would prepare this document prior to the transmitter filing its LTC application. Since the IESO's document would be included in the transmitter's application, the RPPAG recommends that the OEB consider changes to its Filing Requirements for LTC Applications for implementation purposes.

2. ***Distribution Planning:*** LDCs be required to identify if and where there is an inconsistency between their DSP and the RIP in their application, and explain the reasons why, particularly where a proposed investment in their DSP is different from the optimal investment in the RIP. The OEB consider changes to its Filing Requirements for Rate Applications, for implementation purposes.

3. ***Municipal Planning:*** As a component of the RPPAG's "General Education on Regional Planning" recommendation, educate municipalities of the importance of providing information in their municipal energy plan (MEP) that indicates how the MEP goals will be achieved, with a focus on those that include aspirational goals (e.g., net zero) which LDCs cannot translate into load forecasts used in the regional planning process without that necessary information. Also produce a brief document to be provided to municipalities that includes a list of the specific information that LDCs need from municipalities to improve the accuracy of their load forecasts.

4. ***Natural Gas Planning:*** Enhanced coordination between electricity regional planning and natural gas planning be achieved, at this time, via Enbridge's participation in the current Regional Planning processes through the targeted

approaches discussed above, and the OEB only consider regulatory obligations, in the future, under certain circumstances such as the three identified above.

## Open Stakeholder Access to Planning Information / Data

The RPPAG recommends that the IESO share the information it uses for planning purposes with stakeholders that are involved in the regional planning process for reasons that include the following:

- Public trust and stakeholder participation in the regional planning process relies on the availability of information / data before planning decisions are made.
- Stakeholder access to such information would result in more meaningful input during the IESO's stakeholder engagement process related to an IRRP *before* a rate or LTC application is filed with the OEB.
- Stakeholders and OEB staff would also be able to use the information / data to support analysis related to rate and LTC applications *after* they are filed with the OEB.

Planning information should therefore be widely available to interested stakeholders and the OEB to maximize efficiency of the regulatory process (i.e., fewer interrogatories).

The RPPAG notes that shortly after this recommendation was first discussed by the RPPAG, the IESO identified they were already in the process of evolving the information / data that is made available to stakeholders in its "West of London" planning process as part of a pilot project and was doing so in response to stakeholder feedback. The specific information / data that the IESO committed to provide to stakeholders was comprised of the following:

i. Load data (forecast methodology and sensitivities, modelled hourly load profiles, historical hourly load)
ii. Needs identification (transmission interfaces limits and forecast flows, planning criteria, capacity methodology)
iii. Options development and analysis (resource sizing approach, cost and timing assumptions)
iv. Solutions/principles for decision-making

A more detailed breakdown of the information / data that IESO committed to make available to stakeholders, as part of the West of London engagement process, is set out in Appendix B to this report, including the applicable format for sharing the data.

The IESO requested and received feedback in relation to the above information / data and stakeholders supported continued sharing of it. The IESO's response to stakeholder feedback was: "*The IESO agrees that information-sharing can help stakeholders provide feedback and understand planning decisions. Support for these shared data sets … will be considered for future regional and bulk plans.*" The RPPAG is not certain what stakeholder support "will be considered" ultimately means in relation to future regional planning processes.[18]

The RPPAG also notes that, in the most recent IESO Fees case (EB-2020-0230), the IESO agreed to increase the public availability of planning data as part of the approved settlement proposal.

The RPPAG also discussed whether there should be an IESO licence obligation and there was not agreement in relation to that matter. The differing views are summarized below.

*Non-Utility RPPAG Members*

All non-utility RPPAG members recommend that the OEB amend the IESO's licence to include a requirement to share all planning information except where it would pose a risk to system security and/or it is confidential.

Those members are of the view that the rationale for this recommendation is that it is the best way to ensure that stakeholders are provided sufficient planning information at an appropriate time in the regional planning process. As outlined above, the planning process must make planning information available to stakeholders because this creates trust in the planning process, allows stakeholders to bring other options for consideration, and supports the OEB's review of projects in rate and LTC applications. To ensure these benefits are realized, they believe the IESO should be obligated as a condition of licence to maintain transparent and open access to planning data.

The non-utility RPPAG members also believe that allowing the IESO to determine what information it publishes for each regional plan will not support an efficient and successful planning process. To support this view, they identified two recent LTC

[18] IESO responses to feedback, West of London Study, September 23, 2021.

decisions where the approval relied on the IESO's expert determination and the OEB Panel commented that it is important that timely examination of alternatives take place and they not be dismissed as being unable to implemented because of a lack of time.[19] The Decision further noted that "robust stakeholdering and advance planning with potential capacity providers needs to be undertaken as part of initial project steps."[20]

They further noted the stakeholder engagement process is intended to ensure the IESO is provided with a range of views and a range of options to meet power system needs at an early stage. To accomplish this, stakeholders require certainty of the availability of robust planning data and that it be provided on a consistent, transparent, and equal basis. This is best accomplished through specific requirements in the IESO's licence. Doing so would enhance the regional planning process. It would also promote efficiency and effectiveness of any subsequent OEB regulatory process.

Those RPPAG members do not see any other reason not to share such information with stakeholders, as ratepayers have paid for the collection of it. At the same time, those RPPAG members acknowledge it would take time for the IESO to determine the specific details regarding what information and data can be provided. As a result, if the OEB concludes a licence obligation is appropriate, it is recommended that it not take effect until the end of 2022.

*Utility RPPAG Members*

While LDCs that are members of the RPPAG did not take a formal position, Hydro One is of the view that an IESO licence obligation is not required, and this requirement should instead be formalized and documented in the RPPAG Report setting out the regional planning process.

*IESO RPPAG Members*

The IESO does not support this proposed new licence obligation. The IESO already has ongoing efforts to make planning data publicly available and, as such, the IESO does not believe additional licence obligations are needed. The IESO has made public commitments to make planning data available that supports transparent decision making.

[19] Decision & Order (EB-2021-0136 - Upgrading Richview by Trafalgar transmission lines, December 2, 2021, p.8-9). In another Decision & Order (EB-2021-0107, Upgrading Ansonville by Kirkland Lake transmission lines, December 2, 2021, p.7), another OEB Panel referenced the Panel comments in the EB-2021-0136 Decision & Order.

[20] EB-2021-0136 Decision & Order, p.8-9.

The IESO also believes stakeholders and the TWG are best placed to identify the region-specific data needs. The West of London example is evidence of the IESO's information sharing efforts, however, the IESO believes there is insufficient experience to determine its universal applicability to all regions. As the data shared will be plan- and region-specific, the IESO does not believe a licence obligation should be prescriptive on what data is shared, which limits the value of any licence amendment. Further, the IESO is of the view that the two recent LTC decisions referenced above by the non-utility RPPAG members do not address the narrow points of disagreement on whether a licence provision is required and if the West of London example should be applied to all regions of the province.

Given the above, the IESO's recommended approach is to continue to work with stakeholders and the TWG, as required to meet its existing responsibilities, to identify the information, data and applicable sharing formats that support transparent and efficient regional planning.

In summary, the RPPAG is recommending the following:

1. The IESO share the planning information it uses with interested stakeholders, particularly those that are involved in the regional planning process – at a minimum, the information the IESO committed to share in the West of London engagement process.

2. The OEB consider amending the IESO's licence to include a requirement for the IESO to share all planning information, except where it would pose a risk to system security and/or it is confidential, to formalize the sharing of information. If the OEB concludes a new licence obligation is appropriate, wait until the end of 2022 for it to take effect to provide the IESO with the time needed to ascertain which information does not pose a system security risk.

## Existing Option to Bypass IRRP Process: Proposed Approach to Address RPPAG Concerns

Not undertaking an IRRP process and going directly to a RIP process (i.e., only wires solutions considered) has been an option since the regional planning process was implemented in 2013. The RPPAG notes that the system has evolved very much since

2013. The RPPAG therefore has concerns related to bypassing the IRRP process for reasons that include the following:

- It removes potential non-wire alternative (NWA) solutions from consideration before specific NWA solutions, including CDM and DERs, are evaluated to meet regional needs.

- There is now greater emphasis on “meaningful” stakeholder engagement, and unlike the IRRP process, there is no engagement process during the development of a RIP.

The RPPAG considered recommending removal of that option which would have meant an IRRP would always be required if it was determined regional planning was needed in a region. However, a concern was raised that approach would reduce flexibility in the process as it could be concluded in a future Scoping Assessment (SA) process that only wires are a viable option to meet a regional need. In addition, if that occurred, making an IRRP mandatory would reduce efficiency of the regional planning process.[21]

The concerns above were countered by other RPPAG members who pointed out that to determine if only wires solutions are viable, specific non-wires solutions must be assessed to determine if they are viable in meeting regional needs. They felt the SA process cannot adequately assess potential non-wires solutions, since the majority require information from customers, project developers and existing asset operators. Instead, it is the next stage in the regional planning process – the IRRP process – where specific wires and non-wire options are adequately assessed to determine the preferred solution.

The RPPAG’s concerns are alleviated, to some extent, due to the fact that an IRRP has been undertaken in all but one case where regional planning has been required since the process was implemented in 2013. The likelihood that the IESO will conclude an IRRP is not necessary in the future is therefore low; particularly with the increase in emphasis on NWAs and stakeholder engagement since 2013.

[21] The existing regional planning process allows for a wires solution to be “advanced” from the IRRP process to a RIP process at any time. The impact on process efficiency could therefore be minimized if an IRRP was mandatory. For example, if there are two sub-regions, the sub-region with only wires solutions could be “advanced” to a RIP process at the beginning of IRRP process while the IRRP process would continue to address the other sub-region. In other words, the RIP process would not need to be held up for 18 months as suggested by some members during meetings.

That said, the RPPAG's concerns are not fully mitigated. The RPPAG is therefore recommending some process changes:

- Formal criteria that are agreed on by the RPPAG and documented in the RPPAG Report that sets out the regional planning process for transparency (i.e., similar to the criteria added by the previous RPPAG in relation to determining where Local Planning is appropriate). Currently, it is a judgment call that is informed by stakeholder feedback, and the IESO's criteria, which is documented in various IESO reports and stakeholder presentations.

- It is the RPPAG's understanding that few stakeholders now get involved in the stakeholder engagement process during the Scoping Assessment (SA) stage given the outcome has always been the same since 2013 – undertake an IRRP before a RIP. As a result, if a case does arise in the future where the IESO plans to recommend bypassing the IRRP process, the RPPAG is recommending that the IESO should inform stakeholders broadly through an explanation in the IESO's Weekly Bulletin (i.e., not only a link to the SA Report that explains it) before the SA engagement process begins – rather than the current process where only those that read the SA Report would be informed and able to provide feedback.

In summary, the RPPAG is recommending the following:

1. Formal criteria be documented in the RPPAG Report that sets out the regional planning process for transparency that would be used to determine the circumstances under which it would be appropriate to bypass the IRRP process where regional planning is required.

2. If a case does arise in the future where the IESO plans to recommend bypassing the IRRP process, the IESO should be required to inform stakeholders broadly before the Scoping Assessment (SA) engagement process begins (i.e., not the status quo whereby only stakeholders participating in the specific SA process would be informed). The communication tool (e.g., IESO Weekly Bulletin) should also explain it (i.e., not only provide a link to the SA Report that explains it).

## Potential Changes to the OEB's CDM Guidelines to Eliminate Barriers

Note: The following recommendation was provided to the OEB on November 5, 2021. It was advanced ahead of this report so it could be taken into consideration (along with other stakeholder input) in relation to the OEB's update to the CDM Guidelines. It has been included in this report so that all the RPPAG's recommendations are consolidated in one document.

In a recent Integrated Regional Resource Plan (IRRP) – Southern Huron-Perth IRRP – it was identified that a transmission line ("L7S circuit") that connects three LDCs to the bulk transmission network is forecast to reach its capacity limit to supply those LDCs over the longer term. Options considered to meet that capacity need include: (1) an upgrade to the transmission line connecting the LDCs to the system at an estimated cost of $10-15M; and (2) CDM (plus load transfers) to avoid the upgrade to L7S circuit at a lower cost of $6-12M, which includes an assumed $0 cost to consumers because a $26M investment in CDM is expected to be offset by a system benefit (i.e., avoided generation capacity). The IESO recommended the most cost effective (i.e., optimal) solution – combination of CDM and load transfers – to meet that capacity need.

However, the IRRP also stated that a funding mechanism may not be available to enable implementation of that optimal solution when this need materializes. If so, the sub-optimal wires solution would need to be implemented. The IRRP stated the following:

> "Recognizing the most cost-effective solution involves additional conservation, the [Technical] Working Group should also seek regulatory clarity on implementation mechanisms for this solution type in advance of the long-term need materializing, noting that multiple LDCs are supplied by the L7S circuit (i.e., would require clarification of approach if existing CDM Guidelines were to be leveraged for implementation) and the opportunity to leverage some existing mechanisms (i.e., the Local Initiatives Program) may or may not align with when the need materializes." (p.12)

The RPPAG notes that there are two cost responsibility issues in this case. First, there is a transmission asset deferral that is a benefit of the CDM investment. Second, there is a generation asset deferral that is also a benefit of the CDM investment. In neither case is there currently a mechanism to allocate the CDM investment costs to those beneficiaries of the transmission and generation asset deferral.

The most material of the two barriers identified in the IRRP to the implementation of the CDM investment is the deferred cost related to the generation asset. Until this issue is addressed, there is no funding mechanism outside the IESO's Local Initiatives Program (LIP) (as part of the IESO's 2021-2024 CDM Plan) to implement the least cost alternative. This may not be the best solution as the costs are solely recovered through the Global Adjustment (provincial cost recovery), which does not consider the local benefit. The LIP program may also not exist when the long-term need materializes.

The RPPAG therefore recommends that the approach to cost responsibility suggested below in this recommendation be reviewed once the OEB's Framework on Energy Innovation (FEI) initiative reaches a conclusion on defining an approach to measure the benefits of DER use cases relative to costs and assess the value of DERs relative to traditional wires investments.

As noted above, the OEB's CDM Guidelines were also identified in the Huron-Perth IRRP as a potential funding option for the transmission asset deferral. However, the RPPAG notes that funding through the existing CDM Guidelines would not be a viable option because this scenario would involve deferring / avoiding a transmission infrastructure upgrade and funding under the existing CDM Guidelines is limited to avoiding / deferring a distribution infrastructure upgrade. Section 4.1 is specifically entitled "*Applications for Rate-Funded Activities to Defer Distribution Infrastructure*". In addition, the existing CDM Guidelines only appear to contemplate an application from a *single* LDC in referring to "a distributor". In this case, the needs of *multiple* LDCs would be met.

The RPPAG also notes that, if the same transmission line connection (L7S circuit) was owned by an LDC – rather than a transmitter – it would be 'deemed' to be a distribution asset by the OEB and the CDM Guidelines would be a viable option. However, the L7S circuit is owned by a transmitter and is therefore a transmission asset, so the CDM Guidelines are not a viable option. The RPPAG does not believe the type of utility – transmitter vs. LDC – that owns the asset should be a determinant of whether LDCs can leverage the CDM Guidelines for funding a CDM solution.

The RPPAG further notes that, if the higher cost transmission upgrade was implemented, it would be relatively straightforward to implement under the OEB's existing regulatory instruments; specifically, the Transmission System Code (TSC). The transmitter would make the investment (i.e., upgrade the line) and recover a capital contribution from each of the three LDCs *"in proportion to their respective non-coincident incremental peak load requirements"* (i.e., based on proportional benefit) as set out in section 6.3.15 of the TSC. If it was determined that the transmission *connection* upgrade also provided a *network* benefit, a portion of the cost would be recovered from all ratepayers through the transmission network charge under section 6.3.18.

The OEB has indicated its intent to update the CDM Guidelines with the issuance of the OEB staff Discussion Paper related to updating the CDM Guidelines (EB-2021-0106). That Discussion Paper states the following in the OEB staff Proposal related to Regional Planning:

> "The OEB should incorporate any additional **guidance** that arises from the ongoing **Regional Planning Process Review**, including any actions by the IESO to address **barriers to non-wires** alternatives, **into the CDM Guidelines** when appropriate." (emphasis added) (p.12)

The RPPAG believes the recommended changes to the CDM Guidelines set out below are important because virtually all *wires* solutions identified through the regional planning process are *transmission* connection investments (i.e., not *distribution*).

The RPPAG is recommending the following for consideration, as part of the update to the CDM Guidelines, as an incremental improvement in addressing the current barriers related to implementation of the most optimal solution where it involves CDM:

- Allow for CDM funding that defers/avoids *any* type of infrastructure (wires) investment (i.e., also transmission), regardless of what type of electric utility owns the asset.

- Clarify that multiple LDCs (and transmitter, where applicable) are permitted to submit a joint application and should be required to do so where approval of funding for all the applicable LDCs (and transmitter, where applicable) would be required to meet the regional need.

- A joint application would also facilitate the determination of the appropriate cost responsibility among the LDCs. In that regard, the RPPAG also recommends that the approach to cost responsibility be the same as it would be for the transmission solution; that is, based on the proportional benefit. Similar to the TSC, if there was transmission *network* benefit, it would need to be confirmed by the IESO before any costs are recovered from all ratepayers.

However, the RPPAG is also recommending that the CDM Guidelines only be leveraged to address regional needs on a conditional basis; that is, if adequate funding is not available through an IESO program, such as the LIP program. As noted in the OEB staff Discussion Paper, the LIP program was specifically created to procure resources (e.g., CDM) *"for the purpose of addressing needs identified through the regional planning process"*. This recommendation is consistent with the existing CDM

Guideline framework as CDM solutions are typically not eligible for funding under the OEB's CDM Guidelines if the solution is eligible for funding through an existing IESO CDM program.[22]

In summary, the RPPAG is recommending the following:

1. Expand the scope under the CDM Guidelines to also allow for funding that defers/avoids transmission infrastructure investments (i.e., not limit to distribution infrastructure).

2. Clarify that multiple LDCs are permitted to submit a joint application and should be required to do so where approval of funding for all the applicable LDCs would be required to meet the regional need and demonstrate the transmission infrastructure would be deferred.

3. Where there is a joint application, the approach to cost responsibility under the CDM Guidelines be aligned with the approach under the TSC if it was a transmission investment (i.e., based on the proportional benefit).

4. The CDM Guidelines be leveraged to address regional needs on a conditional basis; that is, if adequate funding is not available through an IESO program, such as the LIP program.

5. Undertake another review of the approach to cost responsibility once the OEB's FEI initiative reaches a conclusion on defining an approach to measure the benefits of DER use cases relative to costs and assess the value of DERs relative to traditional wires investments.

Note: Toronto Hydro supports all aspects of this recommendation including the multiple benefiting from the CDM investment being permitted to bring forward a joint application for approval of funding to meet the regional need; however, Toronto Hydro does not support a joint application being required (i.e., those multiple LDCs could request approval of the CDM funding as part of their own individual rate applications).

[22] The CDM Guidelines state: *"Before applying to the Board for CDM funding to defer distribution infrastructure, distributors should confirm that the proposed program is not eligible for funding from the IESO."*

# APPENDIX A

## Regional Planning Process Advisory Group (RPPAG) Membership

| Name | Organization | Type of Representative |
|---|---|---|
| Mark Rubenstein | School Energy Coalition | Consumer |
| Iain Angus | Common Voice Northwest | Consumer |
| Jac Vanderbaan | London Hydro | Distributor |
| Riaz Shaikh | Alectra Utilities | Distributor |
| Matthew Higgins | Toronto Hydro | Distributor |
| Faisal Habibullah | Elexicon Energy | Distributor |
| Robert Reinmuller | Hydro One | Transmitter |
| Jie Han | Canadian Niagara Power Inc., Algoma Power Inc., Cornwall Electric | Distributor and Transmitter |
| Charles Conrad | Association of Power Producers of Ontario | Generator |
| Amber Crawford | Association of Municipalities of Ontario | Municipalities |
| Michael Brophy | Pollution Probe[23] | Municipalities |
| Travis Lusney | Non-Wires Solution Group (NWSG)[24] | Non-Wires (i.e., DER) |
| Chris Codd | Versorium Energy | Distributed Energy Resources (DER) |
| Ahmed Maria<br>Devon Huber | Independent Electricity System Operator | System Operator |
| Cara-Lynne Wade | Enbridge Gas | Natural Gas Distributor |

[23] Pollution Probe is also representing the Clean Air Council (CAC) and Clean Air Partnership (CAP).
[24] NWSG is comprised of Energy Storage Canada (ESC) and Advanced Energy Management Alliance (AEMA).

# APPENDIX B

### IESO's "West of London – Information Sharing Summary"

The IESO noted: "The following table outlines the datasets that will be made available with the West of London (WOL) bulk study, as well as the format."

| Category | Format | Description of Data |
|---|---|---|
| Planning Assessment Criteria | PDF, in report | Technical requirements and standards used to determine needs |
| Load Forecast | PDF, in report | Methodology and sensitivities/known drivers |
| Load Forecast | PDF, in report | Total West of London Annual coincident low, reference, and high scenarios for summer and winter |
| Load Forecast | PDF, in report | Annual station peak forecasts, by region |
| Load Forecast | PDF, in report | Annual greenhouse peak forecasts |
| Load Forecast | PDF, in report | Peak segmentation assumptions for West of London stations with greenhouse load |
| Load Forecast | Excel | Forecast West of London greenhouse hourly load profiles (2021, 2035) |
| Load Forecast | Excel | Forecast West of London total hourly load profiles (2021, 2035) |
| Load Forecast | Excel | Historical hourly station load profiles (2019) |
| Interface Data | PDF, in report | Capacity need methodology, Interface definition, limits, and driving issues |
| Interface Data | Excel | Hourly capacity need, no reinforcements/recommendations (2028-2035) |
| Interface Data | Excel | Hourly capacity need, with near-term recommendations (2028-2035) |
| Interface Data | Excel | Hourly capacity need, with near- and long-term recommendations (2028-2035) |
| Analysis of Alternatives | PDF, in report | Assessment criteria and principles for decision-making |
| Economic Assessment Assumptions | PDF, in report | Assumptions used in the analysis and evaluation of options |

Source: IESO, Electricity Planning in the West of London Area, July 15, 2021

# APPENDIX C

## Summary of Regional Planning Process Advisory Group (RPPAG) Recommendations to the OEB

| Issue | Summary of Recommendations |
|---|---|
| Standardize & Streamline Load Forecast Development | 1. A Load Forecast Guideline to standardize the load forecasts provided by LDCs to the lead transmitter and the IESO.<br><br>2. The load forecast option that entails a 10-year higher level forecast for the Needs Assessment and a more detailed 20-year comprehensive load forecast for the Integrated Regional Resource Planning (IRRP) and Regional Infrastructure Planning (RIP) processes to evaluate specific options to meet the needs. |
| Clarify Scope between IRRP & RIP process – Wires investments | 1. Make the scope of the RIP and the IRRP more clearly defined in the RPPAG Report that sets out the regional planning process to avoid duplication of efforts.<br><br>2. Formalize a process that has occurred but was not contemplated when the current regional planning process was developed involving a material change during the RIP process that triggers a return to the IRRP process.<br>a. This would require an update to the RPPAG Report that sets out the regional planning process and an amendment to the IESO's licence to recognize this scenario.<br><br>3. Formalize that, if any Technical Working Group (TWG) member disagrees with recommended solution in an IRRP and/or RIP, the dissent should be formally documented with reasons for not supporting that solution. |
| Better Consideration of Cost Responsibility in Regional Planning Process | 1. A plain language document be prepared by OEB staff that consolidates and explains the key cost responsibility rules related to regional planning.<br><br>2. A *new OEB Bulletin* be created that provides cost responsibility guidance where communities elect a *premium* solution (i.e., higher cost than the *optimal* solution) that reflects *local preferences* (e.g., DER, rather than wires). |

| Issue | Summary of Recommendations |
|---|---|
| | a. Undertake a review of that Bulletin once the OEB's Framework for Energy Innovation (FEI) initiative reaches a conclusion on assessing the value of DERs relative to traditional wires investments, as that may change how the *optimal* solution is defined.<br><br>3. An *update to the OEB's* [September 2006 Bulletin] that explains the circumstances under which transmission Network upgrade costs should be paid for by a specific customer.<br><br>4. Cost responsibility be addressed in the regional planning process but in a manner that does not result in a deviation from the optimal (i.e., most cost effective) solution. |
| Better Address End-of-Life (EOL) Asset Replacement in regional planning process | 1. A formal process be established that involves Hydro One providing Asset Demographic (i.e., asset age) information to the IESO every five years for categories of major transmission assets that are over 20 years old to provide an indication of their *Expected Service Life (ESL)*.<br>a. The IESO provide access to that Asset Demographic information to all interested stakeholders via a platform that is similar to the New York ISO's CEII process, but less stringent to reflect the relative nature of the information and modified, as appropriate, to reflect Ontario.<br><br>2. All transmission asset owners (TAOs), including the applicable LDCs, provide a 10-year outlook related to the *End-of-Life (EOL)* of major transmission assets to the IESO during the Needs Assessment (i.e., typically every five years).<br>a. The OEB amend the *Distribution System Code (DSC) and Transmission System Code (TSC)* to require providing that EOL information because it is critical to the regional planning process and it involves a number of LDCs.<br>b. The IESO will consolidate EOL information received from the TAOs into a single list, on an annual basis, and make the list available to all interested stakeholders; particularly those in the regional planning process. |
| General Education on Regional Planning Process to Stakeholders | 1. General education sessions related to the regional planning process be conducted involving stakeholders that play a role in the process. |

| Issue | Summary of Recommendations |
|---|---|
| | 2. Those sessions be a coordinated effort involving staff from the OEB and the two entities that lead the stages in the regional planning process – IESO and Hydro One.<br><br>3. Webinars be used as the primary educational tool (with the related presentations and recordings posted, for future reference, until future material changes are made to the process). |
| Holistic Coordination of Planning Processes – Regional, Bulk, Distribution, Natural Gas, Municipal | 1. ***Bulk Planning:*** When the OEB is asked to approve a transmission investment in a leave to construct (LTC) application, the IESO prepare a document that summarizes all the other planned transmission (and non-wire) investments that are set out in regional and/or bulk plans that have linkages and interdependencies. Such planned investments would typically span multiple contiguous regions. The IESO would prepare this document prior to the transmitter filing its LTC application. Since the IESO's document would be included in the transmitter's application, the RPPAG recommends that the OEB consider changes to its *Filing Requirements for LTC Applications* for implementation purposes.<br><br>2. ***Distribution Planning:*** LDCs be required to identify if and where there is an inconsistency between their Distribution System Plan (DSP) and the RIP in their application, and explain the reasons why, particularly where a proposed investment in their DSP is different from the optimal investment in the RIP. The OEB consider changes to its *Filing Requirements for Rate Applications* for implementation purposes.<br><br>3. ***Municipal Planning:*** As a component of the RPPAG's "General Education on Regional Planning" recommendation, educate municipalities of the importance of providing information in their municipal energy plan (MEP) that indicates how the MEP goals will be achieved, with a focus on those that include aspirational goals (e.g., net zero) which LDCs cannot translate into load forecasts used in the regional planning process without that necessary information. Also produce a brief document to be provided to municipalities that includes a list of the specific information that LDCs need from municipalities to improve the accuracy of their load forecasts.<br><br>4. ***Natural Gas Planning****:* Enhanced coordination between electricity regional planning and natural gas planning be achieved, |

| Issue | Summary of Recommendations |
| --- | --- |
| | at this time, via Enbridge's participation in the current Regional Planning processes through the targeted approaches discussed [on page 29 of this report], and the OEB only consider regulatory obligations, in the future, under certain circumstances such as the three identified [on page 29 of this report]. |
| Open Stakeholder Access to Planning Information / Data | 1. The IESO share the planning information it uses with stakeholders that are involved in the regional planning process – at a minimum, the information the IESO committed to share in the West of London engagement process.<br><br>2. The OEB consider *amending the IESO's licence* to include a requirement for IESO to share all planning information, except where it would pose a risk to system security and/or it is confidential, to formalize the sharing of information. If the OEB concludes a licence obligation is appropriate, wait until the end of 2022 for it to take effect to provide the IESO with the time needed to ascertain which information does not pose a system security risk.<br><br>*Note: All non-utility RPPAG members recommend the IESO licence obligation.* [25]<br><br>*The IESO does not support a licence obligation (i.e., continue to leave it to IESO to determine based on stakeholder feedback). The IESO also does not support the West of London pilot being used as the minimum standard for sharing information to apply to all other regions.*<br><br>*Hydro One does not support either a licence obligation or the status quo. Hydro One's preference is to formalize the information to be shared by IESO in the RPPAG Report that sets out the regional planning process.*<br><br>*LDCs members did not take a formal position.* |
| Existing Option to Bypass IRRP Process: Proposed Approach to Address RPPAG Concerns | 1. Formal criteria be documented in the RPPAG Report that sets out the regional planning process for transparency that would be used to determine the circumstances under which it would be appropriate to bypass the IRRP process where regional planning is required.<br><br>2. If a case does arise in the future where the IESO plans to recommend bypassing the IRRP process, the IESO should be |

[25] Non-utility RPPAG members include: Association of Municipalities of Ontario (AMO), Association of Power Producers of Ontario (APPrO), Common Voice Northwest, Non-Wires Solution Group, Pollution Probe, School Energy Coalition (SEC), Versorium Energy (DER developer).

| Issue | Summary of Recommendations |
|---|---|
| | required to inform stakeholders broadly before the Scoping Assessment (SA) engagement process begins (i.e., not the status quo whereby only stakeholders participating in the specific SA process would be informed). The communication tool (e.g., IESO Weekly Bulletin) should also explain it (i.e., not only provide a link to the SA Report that explains it). |
| Potential Changes to OEB's CDM Guidelines to Eliminate Barriers | 1. Expand the scope under the *Conservation & Demand Management (CDM) Guidelines* to also allow for funding that defers/avoids transmission infrastructure investments (i.e., not limit to distribution infrastructure).<br><br>2. Clarify that multiple LDCs are permitted to submit a joint application and should be required to do so where approval of funding for all the applicable LDCs would be required to meet the regional need and demonstrate the transmission infrastructure would be deferred.<br><br>3. Where there is a joint application, the approach to cost responsibility under the CDM Guidelines be aligned with the approach under the TSC if it was a transmission investment (i.e., based on the proportional benefit).<br><br>4. The CDM Guidelines be leveraged to address regional needs on a conditional basis; that is, if adequate funding is not available through an IESO program, such as the Local Initiatives Program (LIP).<br><br>5. Undertake another review of the approach to cost responsibility once the OEB's Framework for Energy Innovation (FEI) initiative reaches a conclusion on defining an approach to measure the benefits of distributed energy resource (DER) use cases relative to costs and assess the value of DERs relative to traditional wires investments.<br><br>*Note: Toronto Hydro supports all the recommendations. The only aspect not supported is the joint application requirement where CDM measures of all LDCs are required to defer the transmission infrastructure and meet the regional need.* |

# APPENDIX D

## Load Forecast Guideline for Regional Planning

*Note: The Load Forecast Guideline is still in the process of being prepared. This report will be updated to include the recommended Load Forecast Guideline once the guideline is finalized.*