EB-2019-0242

ONTARIO ENERGY BOARD

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

APPLICATION TO REVIEW AMENDMENTS TO THE MARKET RULES MADE BY THE INDEPENDENT ELECTRICITY SYSTEM OPERATOR

AFFIDAVIT OF DAVID SHORT
(Sworn October 25, 2019)

October 25, 2019

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1.	Affidavit of David Short, sworn October 25, 2019	
A.	Exhibit “A”	Technical Planning Conference Presentation, dated September 13, 2018
B.	Exhibit “B”	Stakeholder Advisory Committee Presentation, dated August 14, 2019
C.	Exhibit “C”	Resolution of the IESO Board, dated August 28, 2019
D.	Exhibit “D”	Reasons of the IESO Board in Respect of an Amendment to the Market Rules, dated August 28, 2019
E.	Exhibit “E”	Technical Panel Rationale, dated August 13, 2019
F.	Exhibit “F”	IESO Presentation to Demand Response Working Group Regarding Navigant Paper, dated May 11, 2017
G.	Exhibit “G”	IESO Presentation to Demand Response Working Group Regarding Navigant Paper, dated May 30, 2017
H.	Exhibit “H”	Navigant Presentation on Utilization Payments, dated November 16, 2017
I.	Exhibit “I”	Navigant Discussion Paper, dated December 18, 2017
J.	Exhibit “J”	IESO Presentation to Demand Response Working Group on Utilization Payments Discussion, dated March 1, 2018
K.	Exhibit “K”	Energy Payments Stakeholder Engagement Presentation, dated October 10, 2019
L.	Exhibit “L”	Hourly Demand Response (HDR) Testing Update, dated April 25, 2019

TAB 1

ONTARIO ENERGY BOARD

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

APPLICATION TO REVIEW AMENDMENTS TO THE MARKET RULES MADE BY THE INDEPENDENT ELECTRICITY SYSTEM OPERATOR

AFFIDAVIT OF DAVID SHORT
(Sworn October 25, 2019)

I, David Short, of the Region of Halton, in the Province of Ontario, **MAKE OATH AND SAY**:

1. I am the Director of Capacity Market Design for the Independent Electricity System Operator ("**IESO**"). I hold a BSc (Honours) in Applied Science (Electrical Engineering from Queen's University and have more than 25 years of experience in the power sector. I have been employed by the IESO since 2005 in various positions of increasing responsibility and scope. I have held the position of Director of Capacity Market Design since March 2019. Prior to that, I was the Director of Power System Assessments between March 2017 and March 2019.

2. As the Director of Capacity Market Design, I am responsible for overseeing the design and implementation of changes to the IESO's existing demand response capacity auction, including evolving it to acquire power system supply capacity in a manner that increases participation, competition, power system reliability and economic efficiency. As such, I have knowledge of the matters to which I hereinafter depose. Where I have obtained information from others, I verily believe such information to be true.

3. I swear this affidavit in response to a motion filed by the Association of Major Power Consumers in Ontario ("**AMPCO**") seeking to stay the operation of market rule amendment MR-00439-R00 to R05 (the "**Amendment**") pending the Board's review of the Amendment.

The Transitional Capacity Auction

4. The purpose of the Amendment is to implement a Transitional Capacity Auction ("**TCA**") in Ontario.

5. In the context of the IESO-administered markets, "capacity" represents the need to have sufficient resources available to ensure that the demand for electricity in Ontario can be met at all times. At a high level, capacity can be provided by supply resources through energy injections or from loads in the form of demand response. The purpose of a TCA is to create a market-based mechanism that secures incremental capacity to help ensure that Ontario's reliability needs are met in a cost-effective manner.

6. The IESO's previous capacity auction – the demand response auction ("**DRA**") – was introduced in 2015. The DRA consisted of an auction in December of each year for a one-year commitment period starting in May of the following year. If called upon by the IESO, DRA participants fulfilled their capacity obligation by refraining from consuming energy from the IESO-administered market. DRA participants could participate as either a dispatchable load (which responds to a five-minute schedule) or as an hourly demand response participant. DRA participants received availability payments and were subject to non-performance charges.

7. The TCA is the first step in evolving the DRA into a more competitive capacity auction that includes additional resource types. The Amendment enables non-contracted and non-regulated Ontario generators to participate in a capacity auction alongside dispatchable loads and hourly demand response resources.

8. The TCA will run on December 4, 2019 for a commitment period of May 1, 2020 to April 30, 2021. The successful participants in the TCA will be required to become authorized as Capacity Market Participants, which will enable them to register resources with the IESO to deliver on their capacity obligations. TCA participants will receive availability payments for providing auction capacity, subject to non-performance charges.

9. The IESO is planning subsequent phases of its capacity auction design that will enable additional resource types to participate (such as imports and storage) and will introduce new auction features. Each phase is expected to require further changes to the market rules.

10. The IESO plans to increase the forward period for future capacity auctions. The IESO's intention is to run future capacity auctions in June 2020 (for a May 1, 2021 to April 30, 2022 commitment period), December 2020 (for a May 1, 2022 to April 30, 2023 commitment period) and in 2021 (for a May 1, 2023 to April 30, 2024 commitment period).

The Need for a Transitional Capacity Auction

11. The TCA is part of the IESO's strategy to address a significant capacity gap that is forecast to start in 2023. On September 13, 2018 the IESO released the Electricity Planning Outlook that forecasted a capacity deficit in summer 2023 of 3844 MW. A copy of the September 2018 Planning Outlook is attached as **Exhibit "A"** (see page 51).

12. As part of its Market Renewal initiative, the IESO was planning to implement an Incremental Capacity Auction ("**ICA**") which would address the future capacity gap. However, in September 2018 the IESO came to the realization that it was not feasible for the ICA to be launched in time to address the projected 2023 capacity gap and that alternative measures were required.

13. To address this capacity gap, the IESO, in January 2019, announced its intention to enhance the DRA – calling the enhanced auction the TCA – by allowing more resource types to compete. Between February and August 2019, the IESO conducted a formal stakeholder engagement initiative to gather and incorporate feedback from stakeholders on the design of the TCA. Written submissions were received from generators, demand response aggregators, the Market Surveillance Panel, consumers and associations representing local distribution companies, generators and consumers.

14. While work on the ICA was discontinued by the IESO in July 2019, there continues to be a forecasted capacity gap that must be addressed by the IESO to ensure the reliability of Ontario's electricity system. Attached as **Exhibit "B"** is a presentation to the IESO's Stakeholder Advisory Committee dated August 14, 2019 that contains an updated forecast of a capacity gap of approximately 4000 MW in summer 2023 (see page 4).

The Adoption of the Amendment by the IESO Board

15. The Amendment was adopted by the IESO Board at its meeting of August 28, 2019. Attached as **Exhibits "C"** and **"D"** respectively are the Resolution of the IESO Board adopting the Amendment and the Reasons of the IESO Board in respect of the Amendment (the "**Reasons**").

16. The Reasons state that the IESO Board reviewed the market rule amendment materials, including the positions of stakeholders and issues raised during the market rule amendment process, and decided to adopt the Amendment with an effective date of October 15, 2019.

17. The IESO Board identified the following reasons for adopting the Amendment:

a) The Amendment is the first phase in evolving the DRA into a more competitive capacity acquisition mechanism that includes new resource types. This allows for increased competition in the acquisition of capacity for the benefit of Ontario customers.

b) The Amendment enables the IESO to begin implementing the TCA in a phased approach in order to be ready to address forecasted capacity needs in Ontario. The implementation of the first phase of the TCA will enable important experience and learnings with respect to integrating and administering new resource types in the Ontario capacity market sufficiently in advance of more significant capacity needs, currently projected to arise in the 2023 timeframe. A phased approach will reduce risk, while ensuring continued evolution of the market through the phased inclusion of new resources. This is a more prudent approach than attempting to implement a new capacity auction mechanism just prior to the time when there is a more significant capacity need.

c) The Amendment enables non-committed dispatchable generators to participate in the TCA alongside dispatchable loads and hourly demand response resources. The Amendment provides an important opportunity for existing non-committed generators coming off contract to compete to provide reliability services, in this case capacity. In the absence of this opportunity to compete, these generators may choose to wind down their operations to the potential detriment of Ontario reliability and the interests of Ontario customers.

18. In its Reasons, the IESO Board specifically addressed the position of AMPCO that the Amendment unjustly discriminates against demand response resources. The Board noted that AMPCO's position "relies heavily" on Order 745 from the Federal Energy Regulatory Commission ("**FERC**") which requires energy payments to demand response resources when they are dispatched subject to the condition that they meet a "net benefit requirement." The IESO Board observed that FERC Order 745 is not determinative because:

a) while FERC Order 745 is a relevant consideration, it is not binding in Ontario;

b) it is unclear whether the net benefit requirement applies in Ontario, given the differences in Ontario's market design;

c) the IESO has committed to completing an independent study to determine whether there would be a net benefit to Ontario consumers if demand response resources receive energy payments for economic activations; and

d) the energy payment issue is not material because economic activations in the DRA have historically occurred in very limited circumstances and are not expected to be a material consideration for the December 2019 auction.

19. The IESO Board concluded that implementing the Amendment is a prudent decision and that delaying the Amendment until the study is complete would be detrimental to the market overall, as it would "delay the introduction of increased competition, create an unnecessary delay in the phased approach to developing the auction in advance of substantial future capacity needs, and risk failing to retain access to existing generation assets coming off contract." [1]

20. The IESO Board also noted that the Technical Panel recommended the Amendment in a vote of 11-1 and "exercised its discretion on an informed and reasonable basis." A copy of the Technical Panel's Rationale for recommending the Amendment is attached to this affidavit as **Exhibit "E"**.

Stakeholder Engagement on Energy Payments for Demand Response Resources

21. In conjunction with the adoption of the Amendment, the IESO has commenced a separate stakeholder engagement initiative to consider changes to the market rules to provide for energy payments to demand resources as part of future phases of the capacity auction.

22. The provision of energy payments would represent a substantive change to the IESO-administered energy markets. Loads do not receive energy payments under the market structure that has been in place since market opening in 2002. Prices bid by dispatchable loads in the energy market represent a point at which a load no longer wishes to consume electricity.

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[1] Exhibit "D", *Reasons of the IESO Board in respect of an Amendment to the Market Rules* (August 28, 2019), p. 4.

23. The IESO previously studied the merit of utilization payments[2] for demand response resources through its Demand Response Working Group ("**DRWG**"). In July 2017, the IESO retained Navigant Consulting ("**Navigant**") to provide research on utilization payments and inform a dialogue on their possible merits to drive additional, economically efficient demand response to meet a variety of electricity system needs. Navigant examined practices adopted in other markets and considered arguments for and against providing utilization payments.

24. In December 2017, the IESO released a Discussion Paper prepared by Navigant, which concluded that in considering the case for utilization payments in Ontario:

> The arguments for and against utilization payments are nuanced and prudent. Responsible stakeholders can arrive at different conclusions based on preferences for evaluation criteria.
>
> A unique consideration for Ontario is that today, almost all generation resources are compensated under long-term contract or through regulation that guarantees a certain level of revenue. The economic efficiency arguments under this current market structure are different than they would be if considering the future state of the wholesale power market where generation resources are largely compensated through energy and capacity market revenues. Under the current conditions, more DR activation (as a result of bidding into the market at prices lower than traditional generators) would not actually lead to reduced costs to consumers since generators have their compensation guaranteed.

Attached as **Exhibits "F"**, **"G"**, **"H"**, **"I"** and **"J"** respectively are a copy of IESO presentations dated May 11, 2017 and May 30, 2017; a Navigant presentation on utilization payments dated November 16, 2017; the Navigant Discussion Paper, dated December 18, 2017; and an IESO presentation, dated March 1, 2018.

25. The issue of utilization payments for demand response resources resurfaced in 2019 as part of the IESO's stakeholder consultation on the implementation of the TCA. Due to the complexity of the issue, the IESO ultimately determined that a broader stakeholder engagement

[2] Navigant defined a utilization payment as a payment made to demand response resources when they are called upon to modify their load. A utilization payment could be an energy payment or some other form of compensation.

was needed to consider the issue. The IESO decided to commission a study to examine whether there is a net benefit to Ontario electricity ratepayers if demand response resources are compensated with energy payments for economic activations.

26. On August 22, 2019, the IESO launched a stakeholder engagement initiative entitled *Energy Payments for Economic Activation of Demand Response Resources* (the "**Energy Payments Stakeholder Engagement**"). The IESO commissioned a third-party consultant, Brattle Group, to support the research and analysis and is currently seeking stakeholder feedback on the "[i]nputs and outputs of third-party research and analysis to inform [the] IESO's decision on the energy payment issue". A copy of a presentation made by the IESO at the October 10, 2019 stakeholder meeting is attached as **Exhibit "K"**.

27. The IESO expects to present its draft decision and rationale on the issue for stakeholder review in May 2020 and render a final decision and rationale in June 2020. The IESO would then commence the market rule amendment process for any changes that are needed to implement the decision.

The IESO's Decision to Proceed with the TCA

28. Preparations are currently underway for the TCA on December 4, 2019. In addition to demand response resources, four market participants representing generators have already registered with the IESO as capacity auction participants.

29. As stated by the IESO Board in its Reasons, the IESO has decided to proceed with the TCA in parallel with the Energy Payments Stakeholder Engagement in order to ensure that the IESO will be prepared to address the significant capacity gap that is projected to arise in 2023.

30. Due to the complexities of creating an enduring capacity auction, it would be impractical and imprudent to attempt to introduce the full suite of changes required on the eve of the significant capacity need the auction would be required to address. Progressing in a phased approach, as the IESO has planned, allows the IESO to:

a) introduce new resource types into the auction gradually;

b) assess and respond to how new resource types behave in the capacity auction;

c) provide participants with an opportunity to develop and test business processes and business models to support their participation in capacity auctions;

d) provide participants an opportunity for price discoverability;

e) ensure that committed capacity resources are capable of satisfying their capacity obligations;

f) provide sufficient time to assess and evolve auction design features, informed by stakeholder input;

g) allocate the necessary resources to implement new auction design features in manageable steps; and

h) monitor and identify unforeseen consequences arising from new auction design features.

31. It is critical that the IESO evolve its capacity auction in a manner that promotes confidence in the auction process amongst existing and potential auction participants. A phased implementation of changes will help promote that confidence and is consistent with the IESO's general practice for prudently evolving market design incrementally.

32. Given the short timeframe in which the IESO must be prepared to meet the 2023 capacity gap, it is critical that the phased implementation of the enduring capacity auction begin with the TCA in December 2019. As stated at paragraph 10 above, there are only three planned auctions (December 2019, June 2020 and December 2020) before the IESO undertakes the auction for the critical summer 2023 period. This provides for limited opportunities for the IESO to execute, learn from and evolve the TCA prior to 2023.

33. As stated above, the introduction of energy payments for demand resources would be a substantive change to the fundamental design of the IESO-administered energy market. While the IESO has committed to studying the issue as part of the Energy Payments Stakeholder Engagement, the IESO is not prepared to forego the planned auctions to await the outcome of the Energy Payments Stakeholder Engagement. Any delays in the implementation of the planned auctions will reduce the margin for error and may force the IESO to rely upon less competitive mechanisms to address the capacity gap in 2023.

34. The IESO cannot rely upon the existing DRA to produce sufficient capacity to satisfy the coming capacity gap. The last DRA in December 2018 attracted a qualified capacity of over 1000 MW. This is insufficient to meet the forecast capacity gap of approximately 4000 MW in summer 2023. Hourly demand response resources also have a history of poor performance during test activations. Between February 2018 and January 2019, hourly demand response resources had a 58% failure rate for test activations which were four hours in duration. Attached as **Exhibit "L"** is a copy of the Hourly Demand Response (HDR) Testing Update presented to the DRWG on April 25, 2019 (see page 6). These results suggest that the actual capacity available to the IESO under the DRA may be substantially less than the results of prior DRA auctions suggest.

35. As noted by the IESO Board in its Reasons, the IESO believes that allowing supply resources to compete in the TCA will reduce the likelihood that the operation of generation facilities coming off contracts will be shut down. These generation assets could play a role in addressing the future capacity gap and increasing competition in future capacity auctions. The IESO is concerned that some of these generation resources may cease operations if the TCA is delayed as they will have no opportunity to compete in the IESO's capacity auction.

36. The IESO Board concluded that access to energy payments for demand response resources is not expected to have a material impact on the TCA. Demand response resources have been activated in very limited circumstances under the DRA. Hourly demand response resources have only been economically activated on one occasion since the introduction of the DRA; and dispatchable loads have been dispatched less than 1% of the time over that same period. The IESO does not expect the likelihood of economic dispatch to appreciatively increase in the commitment period under the December 2019 auction (May 1, 2020 to April 30, 2021).

SWORN BEFORE ME at the City of Mississauga, in the Province of Ontario, on October 25, 2019. Commissioner for Taking Affidavits LSUC : 59826S	DAVID SHORT

TAB A

EXHIBIT "A"

referred to in the Affidavit of

DAVID SHORT

Sworn October 25, 2019

Commissioner for Taking Affidavits

LSUC : 59826S

2018 Technical Planning Conference

September 13, 2018

Connecting Today.
Powering Tomorrow.

Background and Overview

Purposes of today's conference

Purposes:

- To support greater transparency in the IESO's bulk system planning processes
- To provide stakeholders with an update on the IESO's electricity planning outlook
- To provide an overview of transmission planning
- To discuss competitive transmission procurement processes that the IESO is developing

Opportunities for feedback

Feedback:

- You will have the opportunity to ask questions and provide feedback during today's presentation

- Stakeholders are also invited to provide written feedback or comments on
  - The effectiveness of the conference overall
  - The contents/questions posed during today's presentation
  - Information you would like to see at future conferences

- Email us: engagement@ieso.ca

- Today's presentation materials will be available on our website

http://www.ieso.ca/en/sector-participants/planning-and-forecasting/technical-planning-conference

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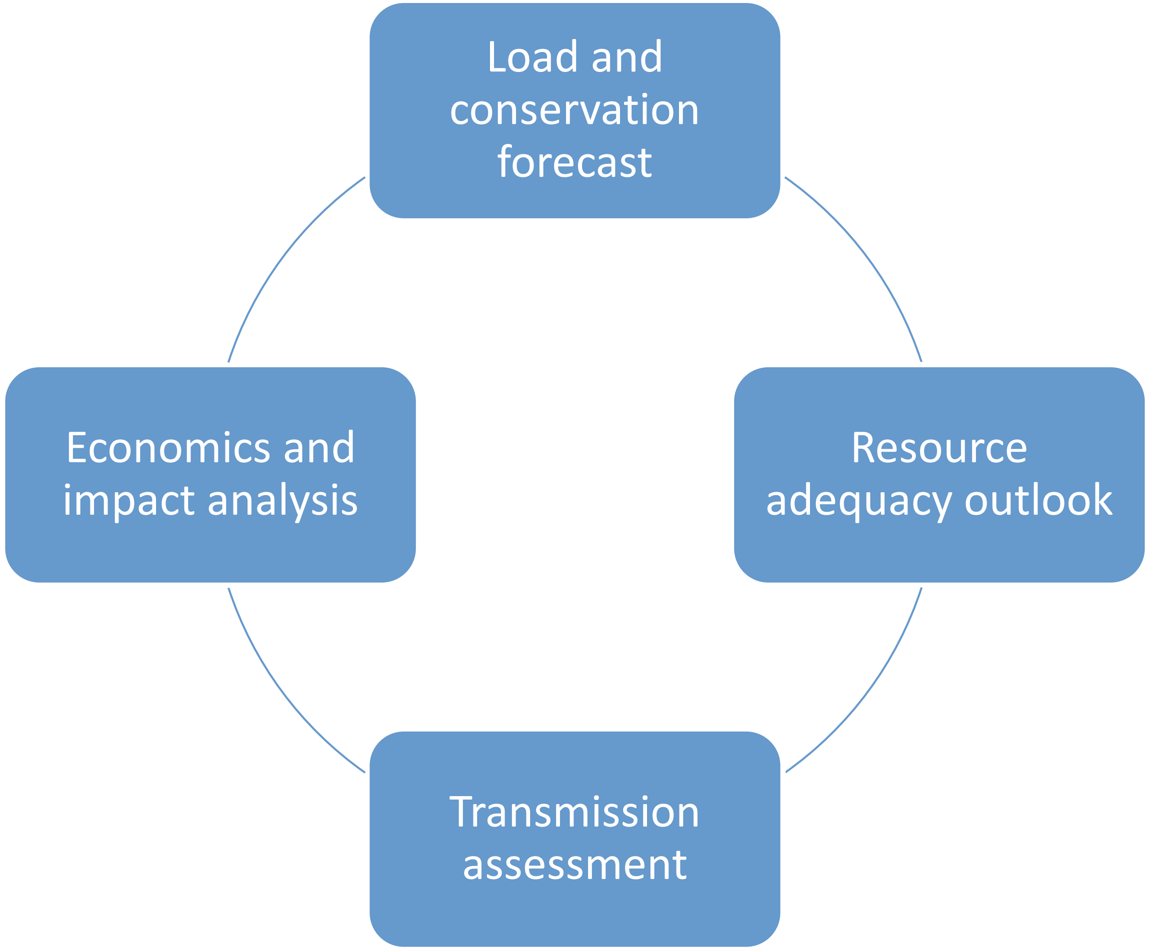
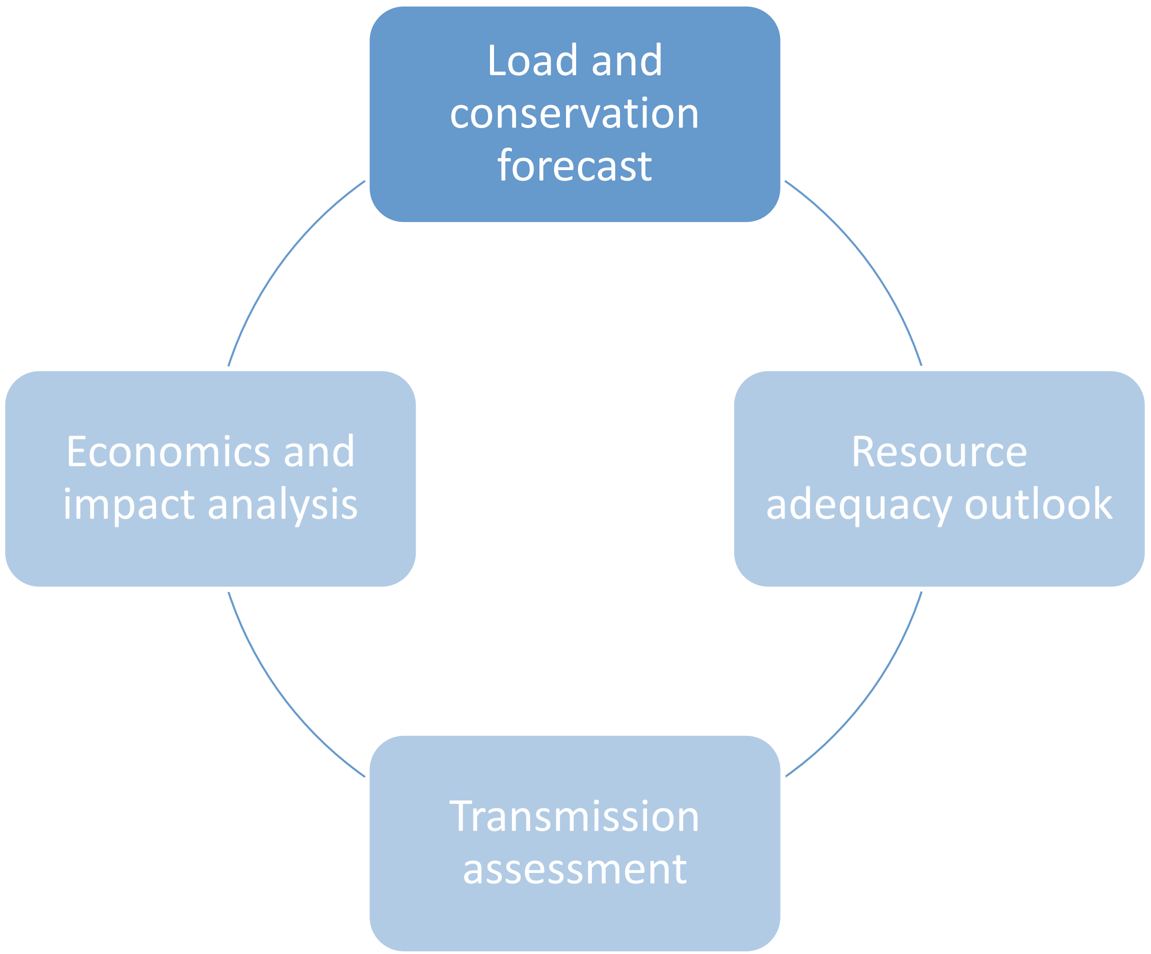
Planning Processes and Long-Term Electricity Outlook

Bulk system planning process



Bulk system planning process – Load and conservation forecast



The role of long-term demand forecast

- Electricity demand forecasting anticipates future requirements for the services that electricity provides.

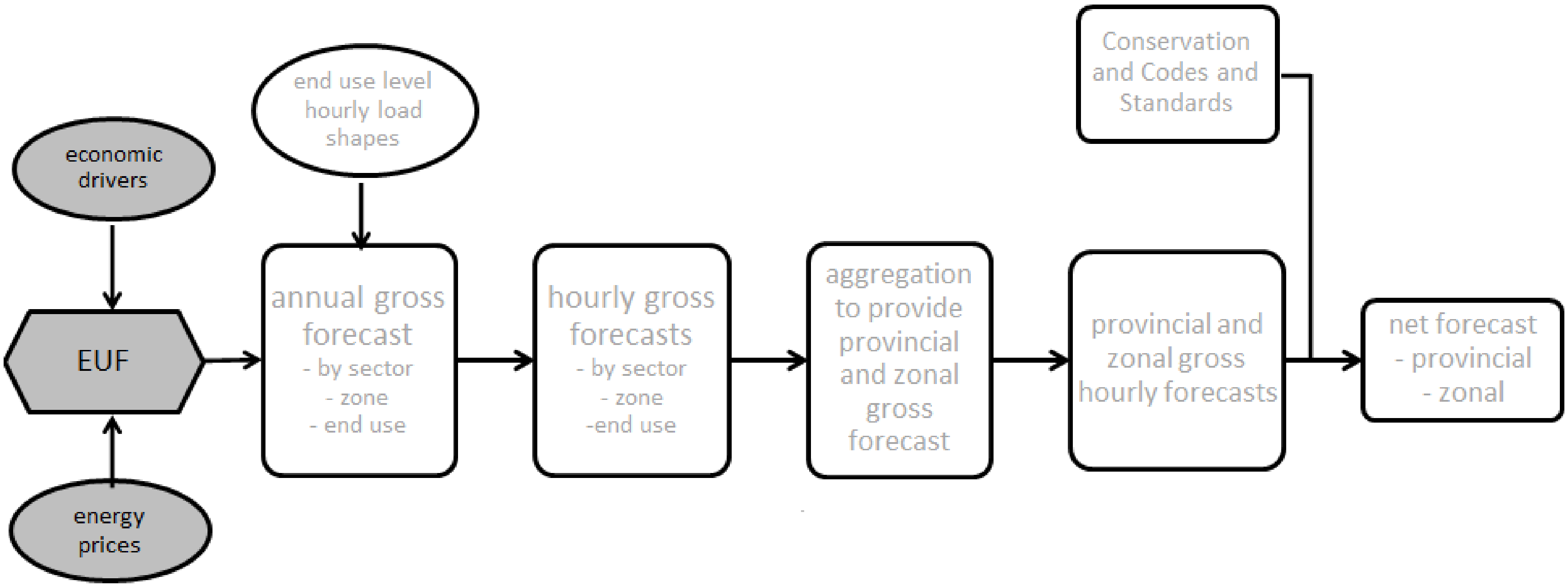
- The IESO conducts short, medium and long-term integrated power system planning for the province.

- Updates to the load forecast provide context for updated integrated plans, conservation program planning and supply procurement decisions.

- Electricity requirements are affected by many factors, including choice of energy form, technology, equipment purchasing decisions, behaviour, demographics, population, the economy, energy prices, transportation policy and conservation. The IESO monitors and interprets these and other factors on an ongoing basis to develop outlooks against which integrated planning can take place.

How we develop the long-term load forecast

Load forecasting process



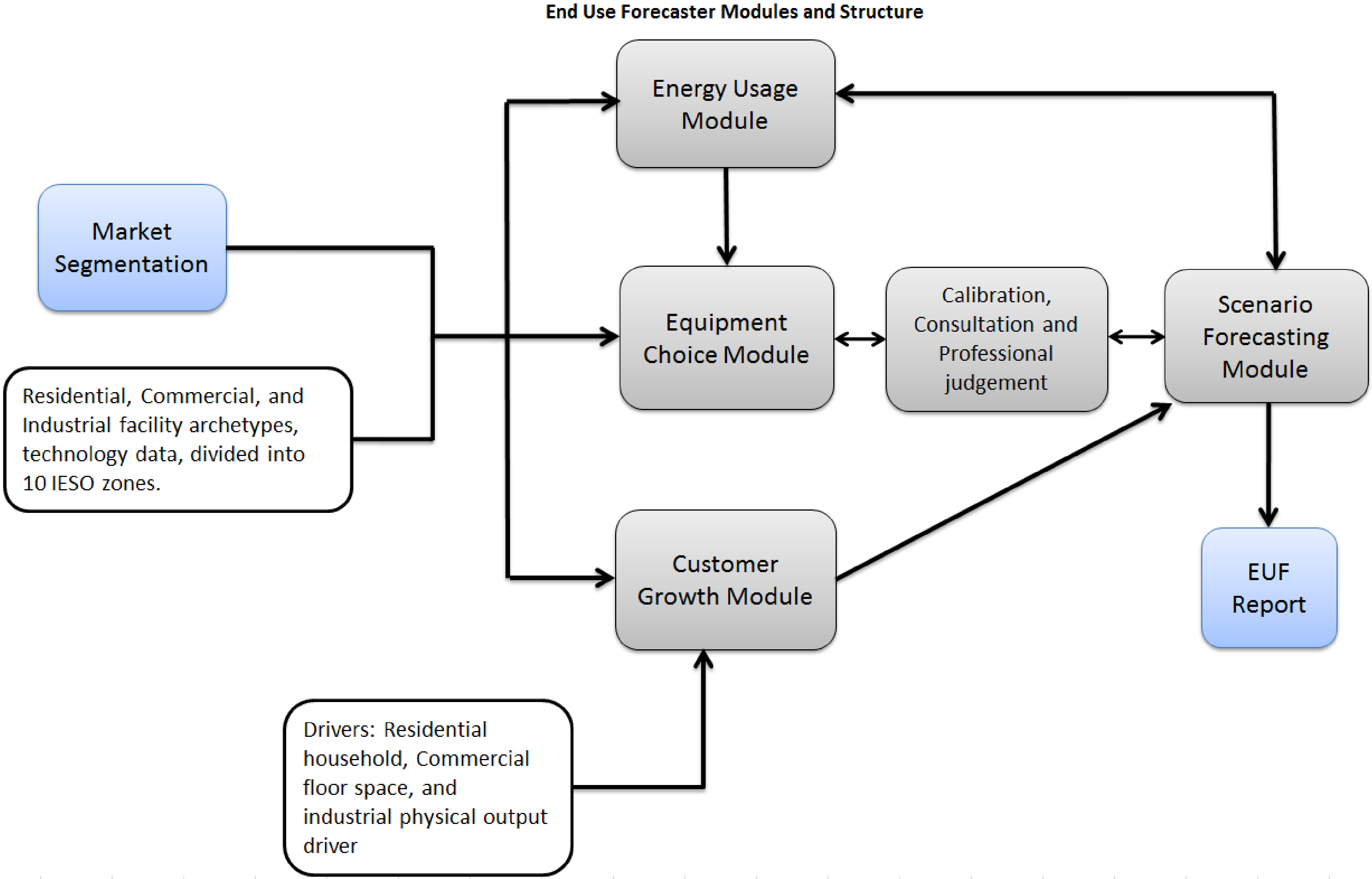
Key drivers considered for electricity demand

- **Major economic drivers:**
  - Residential households
  - Commercial floor space
  - Gross Domestic Product (Real GDP, manufacture GDP, service sector GDP)
  - Industrial output/activities

- **Electricity price and natural gas price forecast:**
  - High electricity price results in greater natural efficiency uptake
  - Rate design impacts – annualized price effect of the Industrial Conservation Initiative is included in the sector price forecast

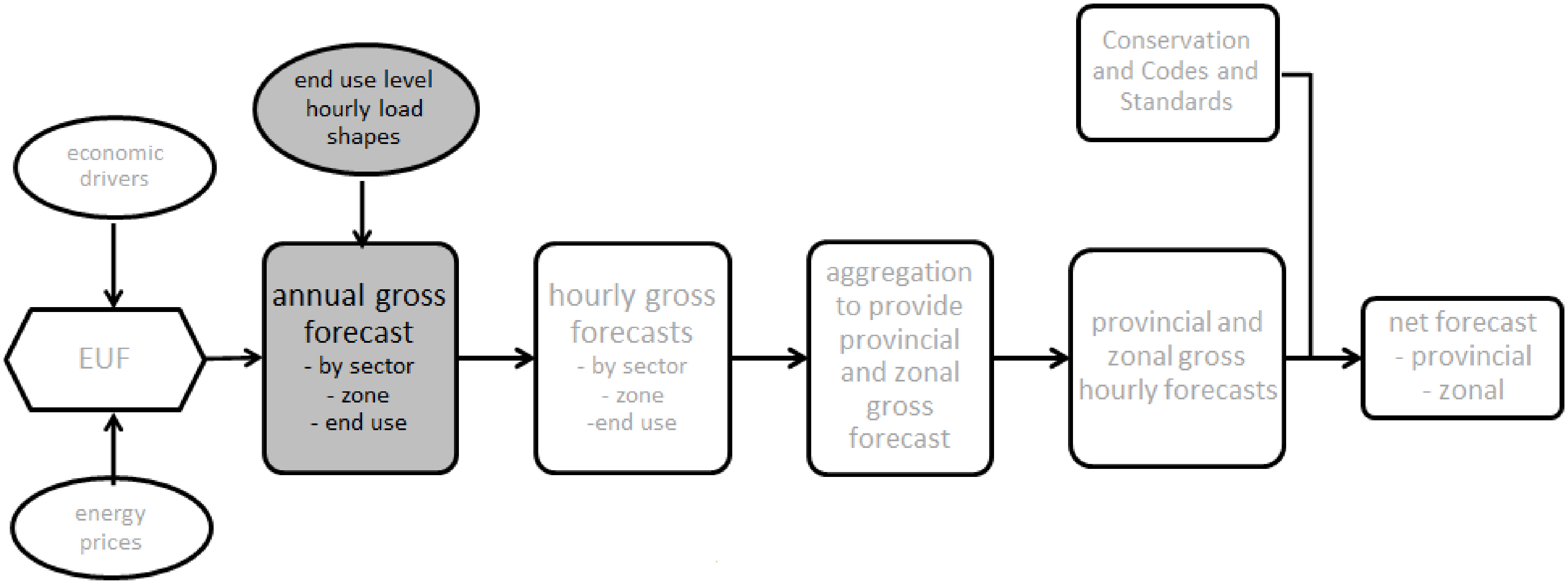
- **Conservation forecast**
  - Energy efficiency programs
  - Codes and standards

End Use Forecaster (EUF) model schematic



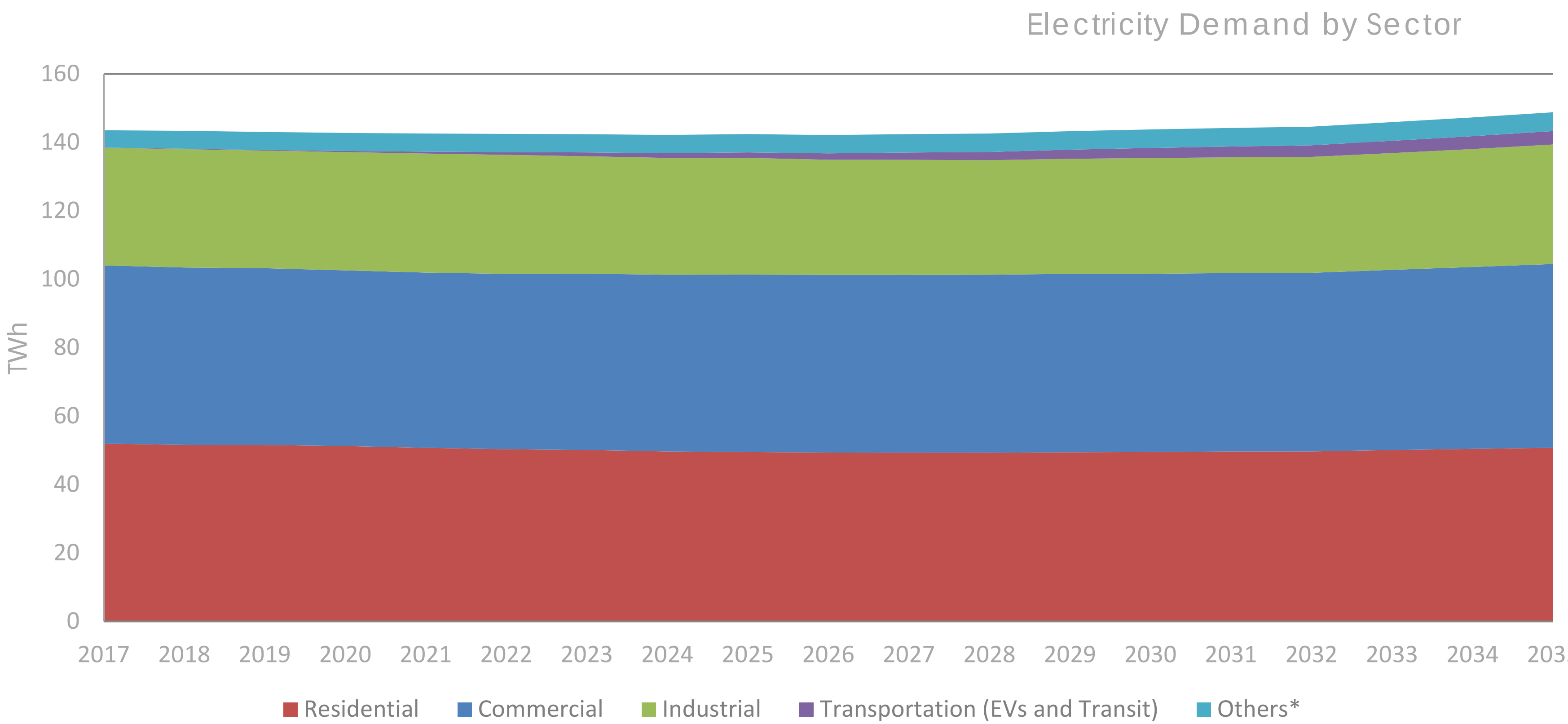
How we develop long term load forecast

Load forecasting process



Demand sector – Reference Forecast

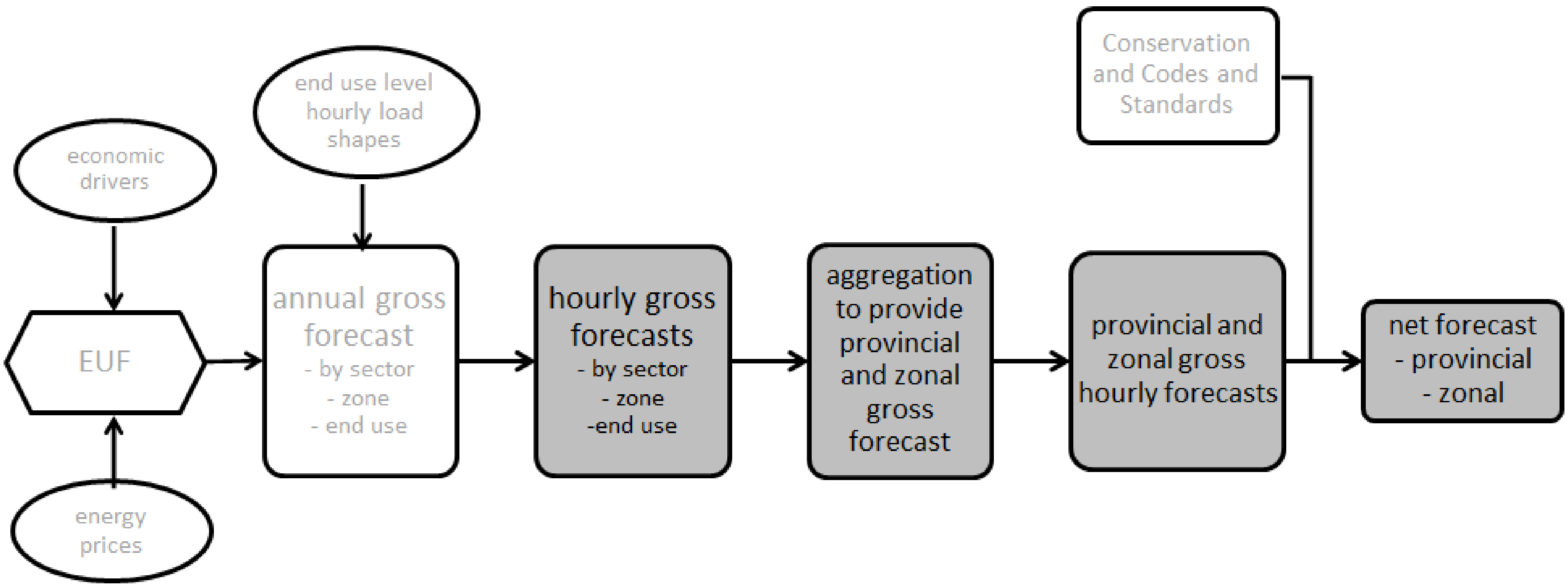
- Composition of electricity demand by sector is not expected to vary significantly in the planning horizon.



* Others = Agriculture, Remote communities, Generator Demand, IEI and Street Lighting

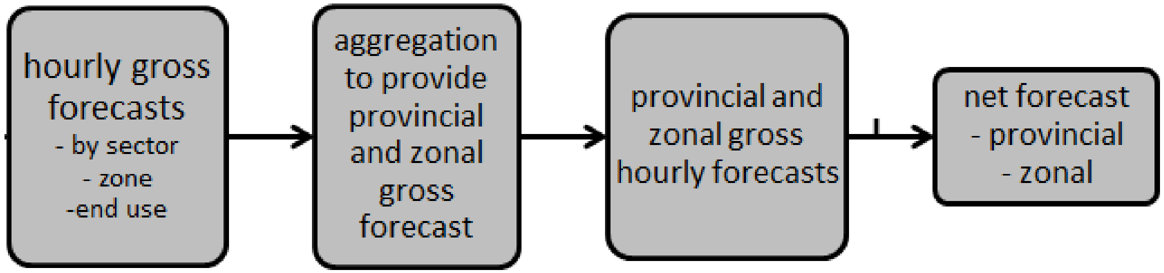
How we develop long term load forecast

Load forecasting process

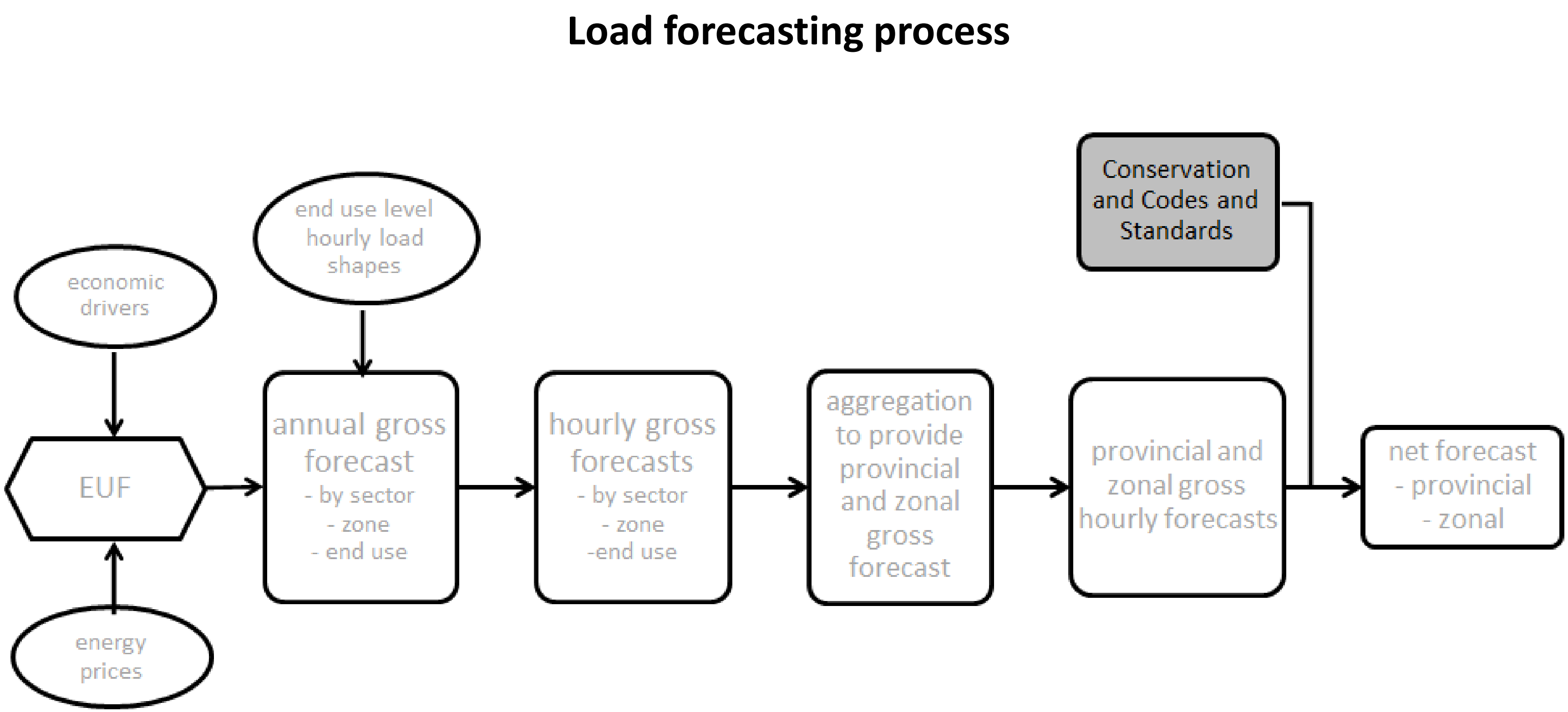


How we develop the long-term load forecast

Load forecasting process



How we develop the long-term load forecast



How is conservation considered in the IESO's planning outlook?

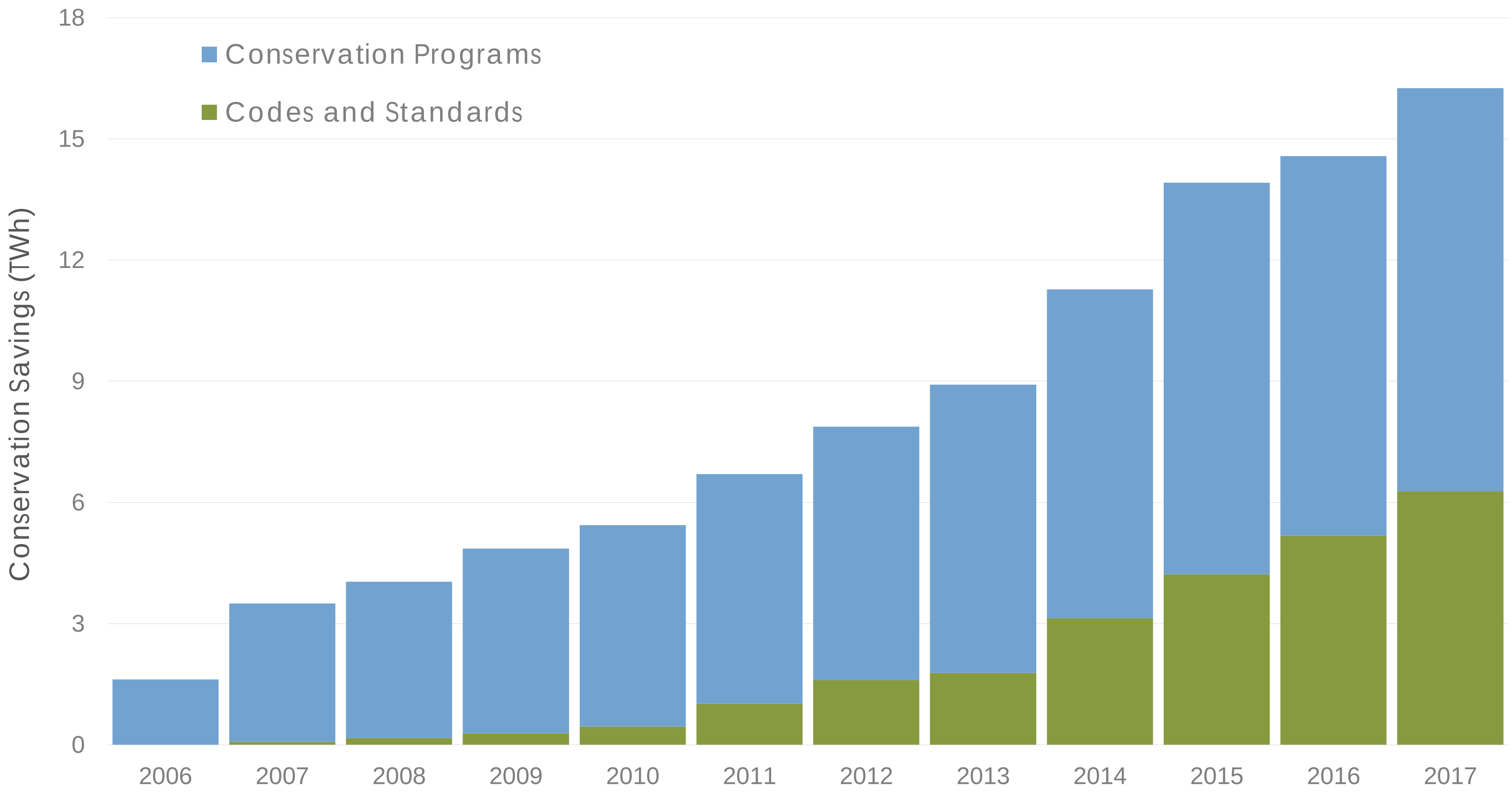
Gross Demand: is the total demand for electricity services in Ontario prior to the impact of conservation programs

Net Demand: is Ontario Gross Demand minus the impact of conservation programs

- Conservation and Demand Management (CDM) consists of activities that reduce electricity consumption and/or peak demand.
- Forms of CDM include energy efficiency, and codes and standards.
- Net load forecast: Energy efficiency and codes and standards are subtracted from the *gross load* forecast to derive the *net load* forecast.
- Gross load forecast: Savings from demand response and customer based generation are treated as supply resources in the IESO's integrated analysis and are not deducted from the gross load forecast.

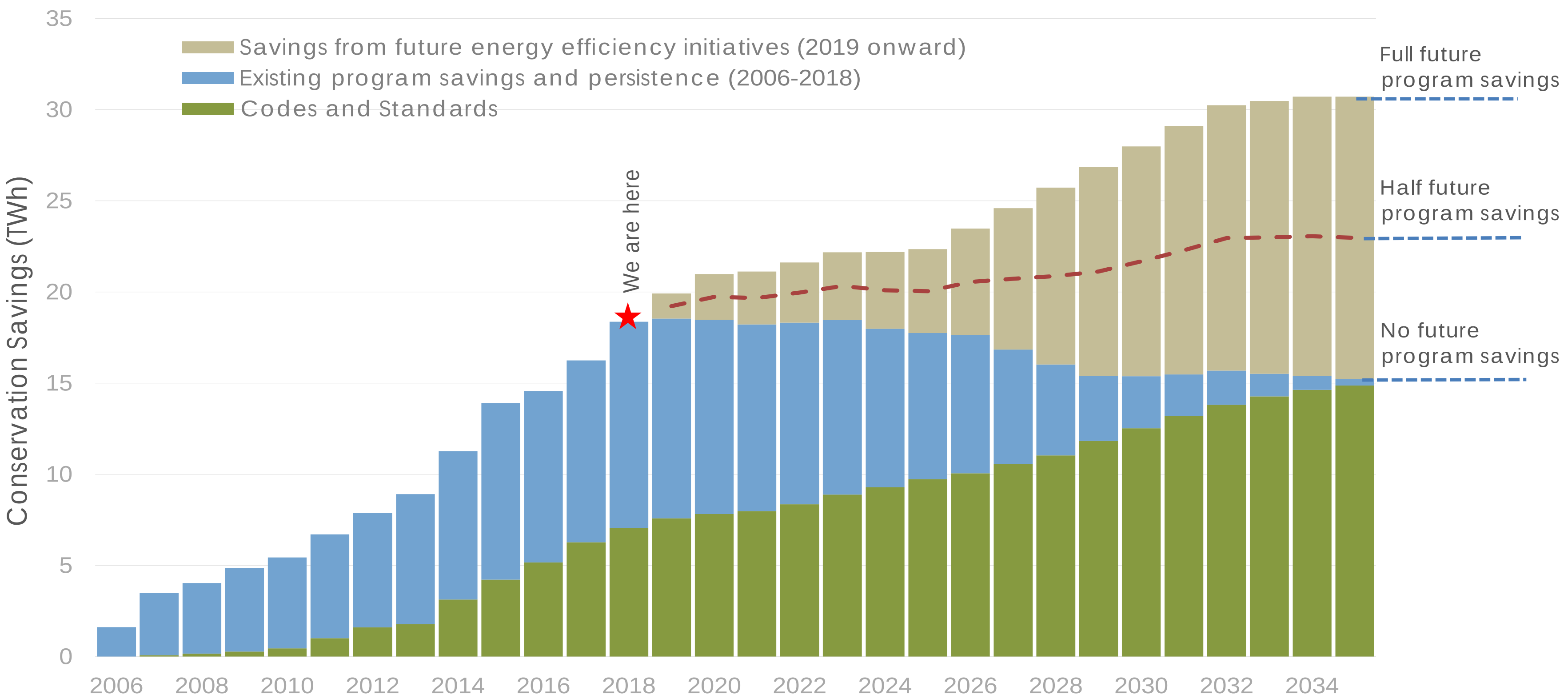
Conservation achievements: 2006-2017

- From 2006 to 2017, conservation savings continued growing, reached over 16 TWh in 2017
  - 10 TWh savings have been achieved by conservation programs, driven by education and financial incentives
  - 6 TWh savings have been achieved by minimum efficiency regulations like building codes and equipment standards



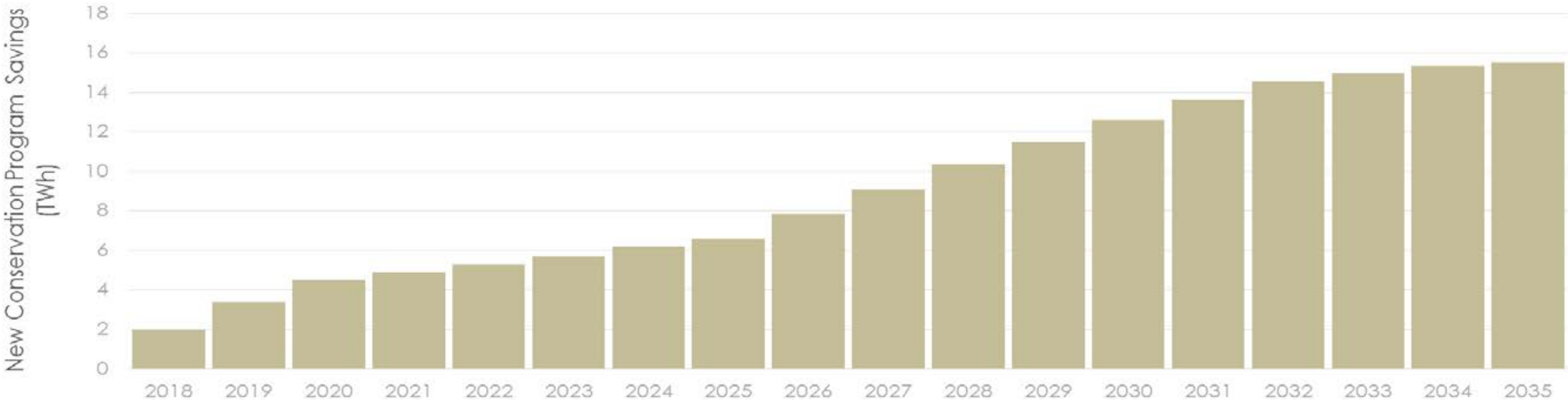
Long-term conservation forecast of 32 TWh by 2035

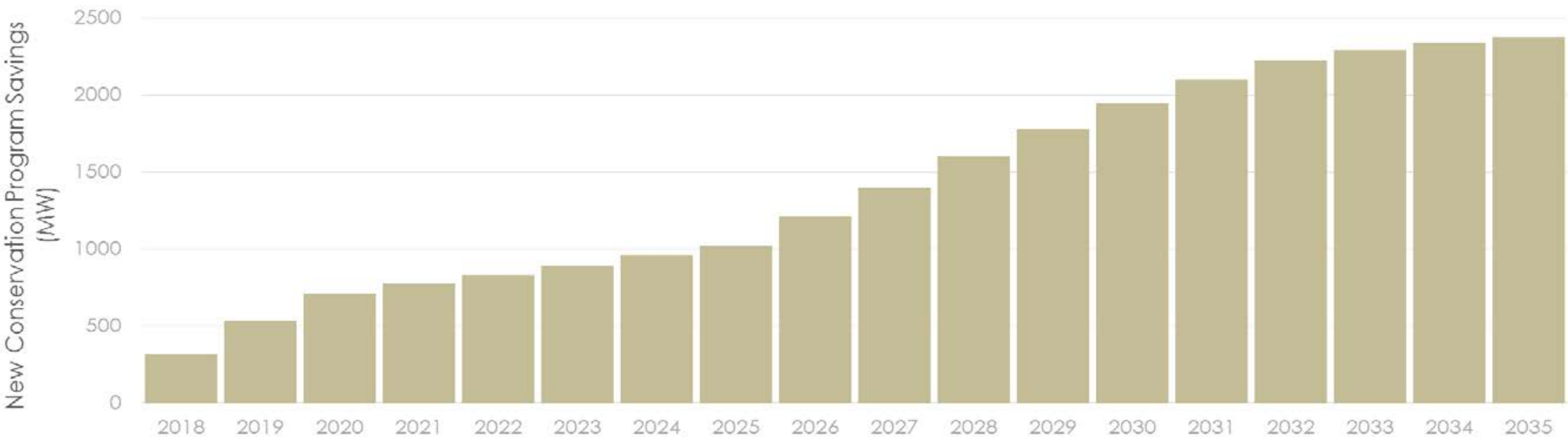
- The reference demand outlooks reflects achievements of the full conservation forecast achieved by 2035
  - 50 % of forecasted savings are from codes and standards and 50% from conservation programs. Ontario is on track to achieve about 18 TWh by 2018.
  - Codes and standards savings will continue to grow while historical program savings decay.



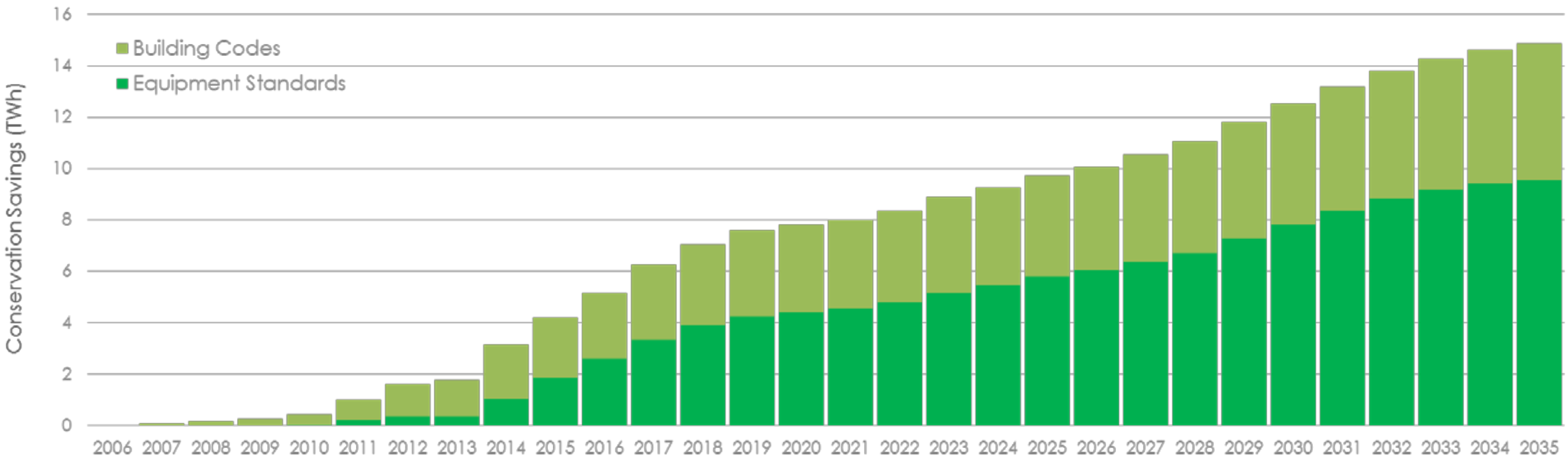
Long-term conservation forecast

- New, future conservation programs represent about 15 TWh energy savings and 2,400 MW of peak demand savings by 2035.
- Between 2018 to 2035, we see incremental conservation savings from new programs, which is in addition to incremental savings from codes and standards.





Factoring in codes and standards



- An effective energy efficiency tool that embeds energy savings in buildings and equipment upgrades and requires no incremental electricity fees.
- Savings from codes and standards are forecasted to be approx. 15 TWh by 2035.
- Methodology of estimating savings from codes and standards
  - Codes and standards savings estimates are based on the expected improvement in the codes for new and renovated buildings and for specified end uses through the regulation of minimum efficiency standards for equipment.
  - The IESO estimates savings to be attributed to codes and standards by comparing the gross forecast to the forecast adjusted for the impacts of regulations.

Grid demand considerations

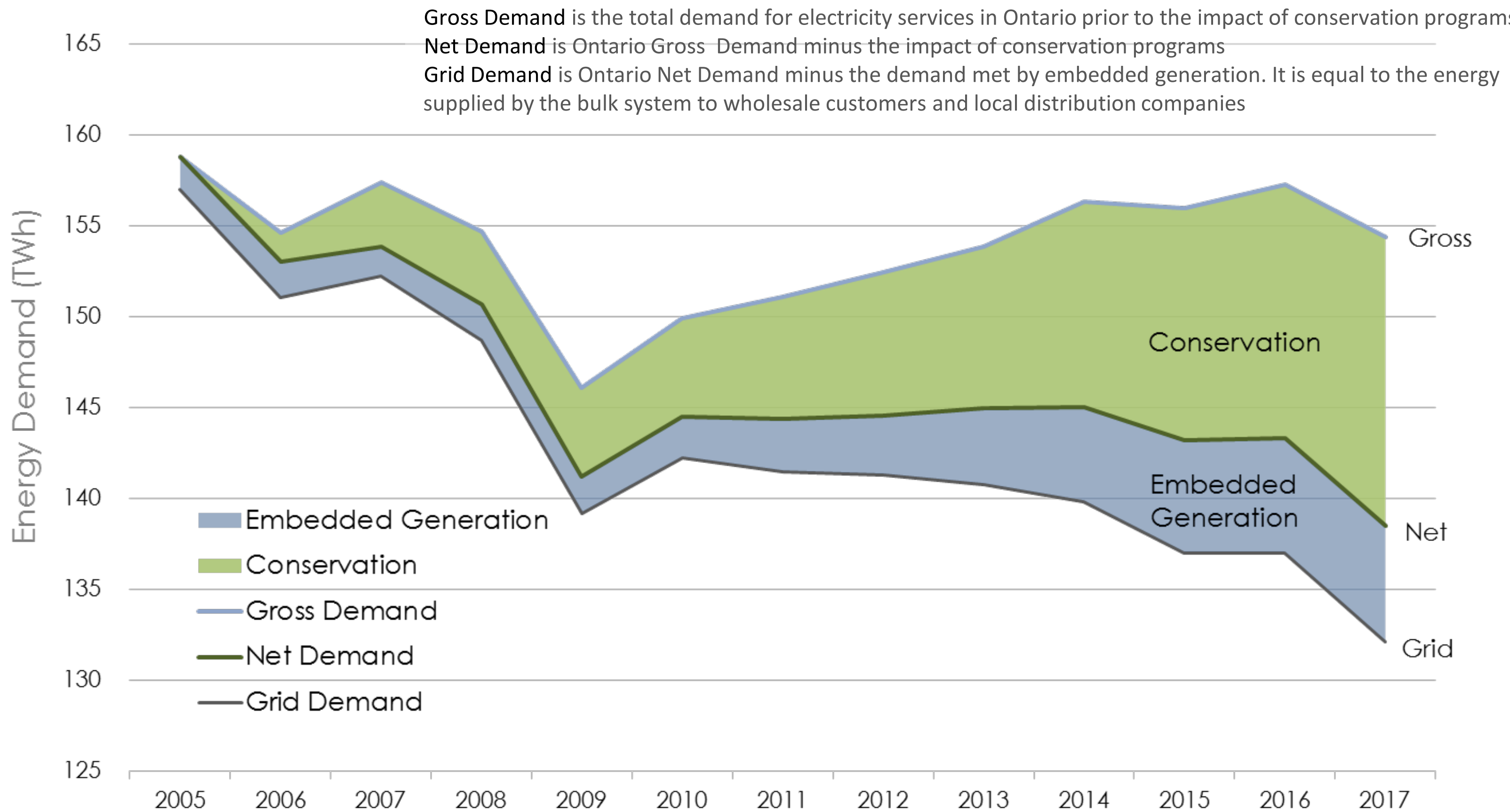
Gross Demand: is the total demand for electricity services in Ontario prior to the impact of conservation programs

Net Demand: is Ontario Gross Demand minus the impact of conservation programs

Grid Demand: is Ontario Net Demand minus the demand met by embedded generation. It is equal to the energy supplied by the bulk system to wholesale customers and local distribution companies through the IESO-administered markets

Historical demand: 2005 – 2017

- Energy demand has been on a declining trend over the past decade, driven by changes to the economy, conservation savings, and embedded generation.



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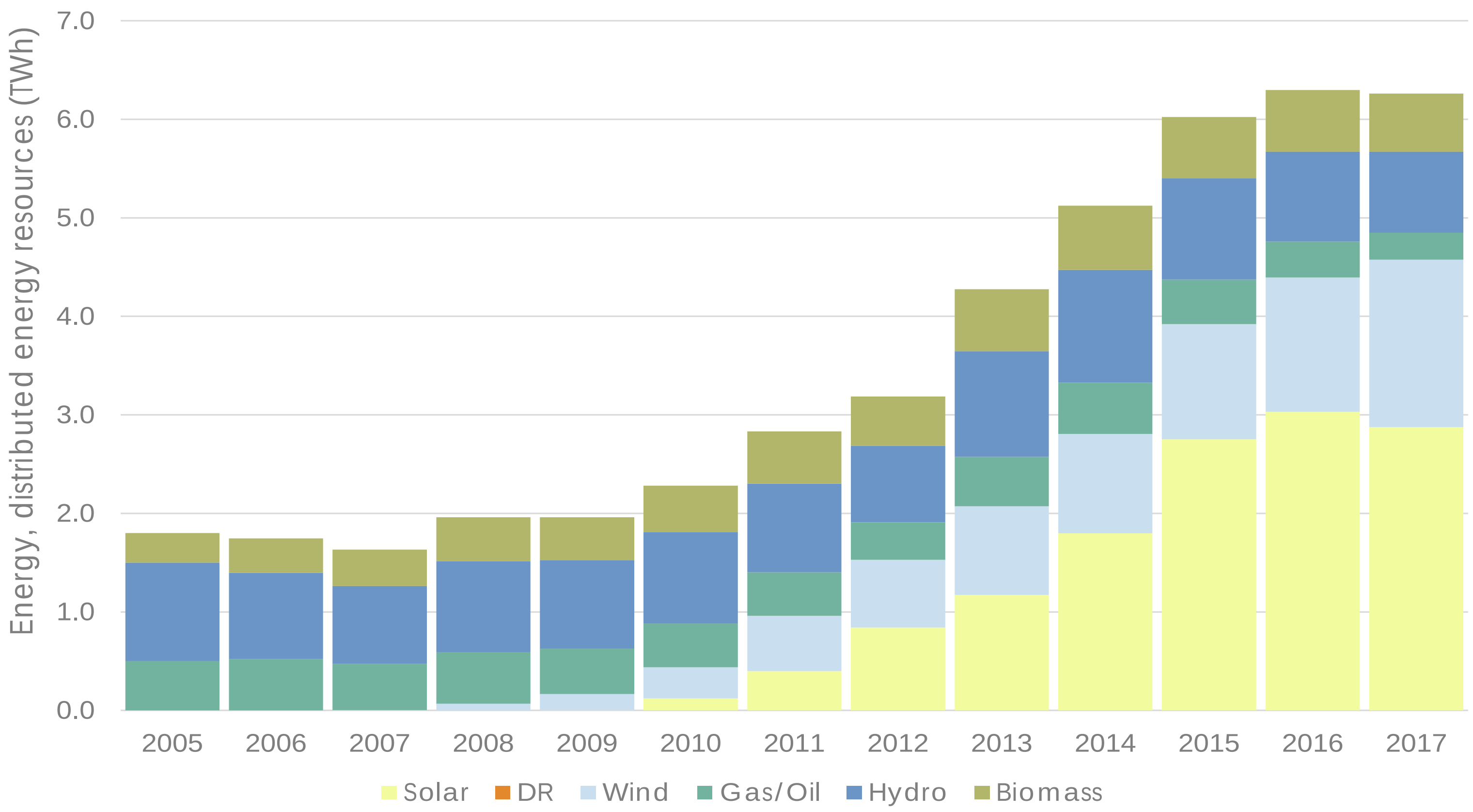
Historical embedded generation: By fuel type

- Embedded generation reduces bulk electricity demand.
- More than 6 TWh of embedded generation, approximately 50% solar, has been added since 2005. This has been driven by incentives provided through various procurements such as the FIT and microFIT programs.
- Future growth will depend on success of net metering programs and continued decline in technology capital costs.

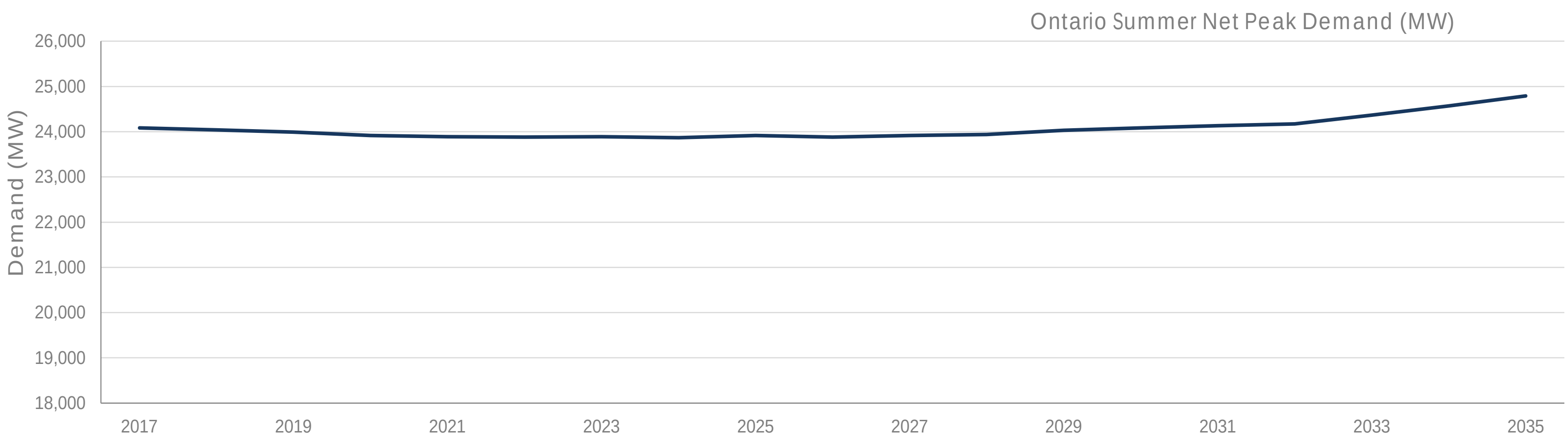


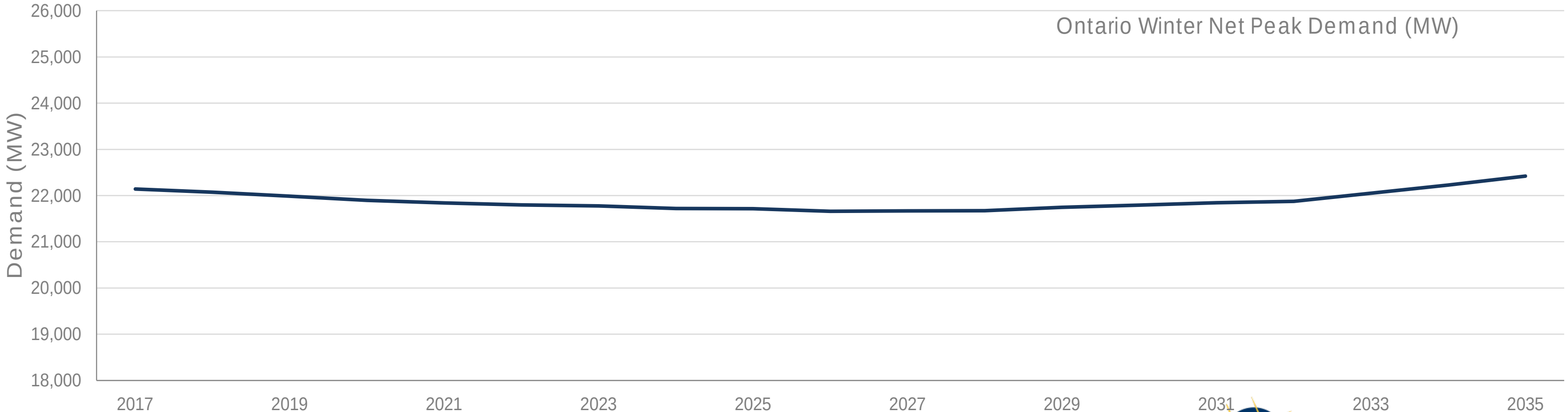
Energy demand by sector: Scenario/Outlooks, with key assumptions

Sector	A) Lower Demand Scenario	B) Reference Case	C) Higher Demand Scenario
Residential	Households grow 20% from 2015 to 2035	Households grow 24% from 2015 to 2035	Same as Outlook B
Commercial	New square footage growth in various buildings decrease by 50% in comparison to other outlooks	Total commercial square footage is 4,093 million by 2035	Same as Outlook B
Industrial	Industrial economic restructuring	Industrial electric consumption in the absence of economic restructuring	Same as Outlook B
Electric Vehicles	0.6 million EVs by 2035	1.0 million EVs by 2035	Same as Outlook B
Transit	Projects with committed funding	Planned projects, 2025-2035	Same as Outlook B
Conservation	31TWh savings by 2035	31TWh savings by 2035	15TWh savings by 2035
Summary	Slower growth, industrial economic restructuring and faster move to a service oriented economy	Flat demand growth as a result of conservation	Higher demand as a result of absence of new conservation programs

Reference Case: Demand outlooks - summer and winter peak

- Electricity demand, after the impact of conservation savings, is the starting point for addressing future system needs. The 2016 OPO Demand Outlook B is used for the Reference Case.





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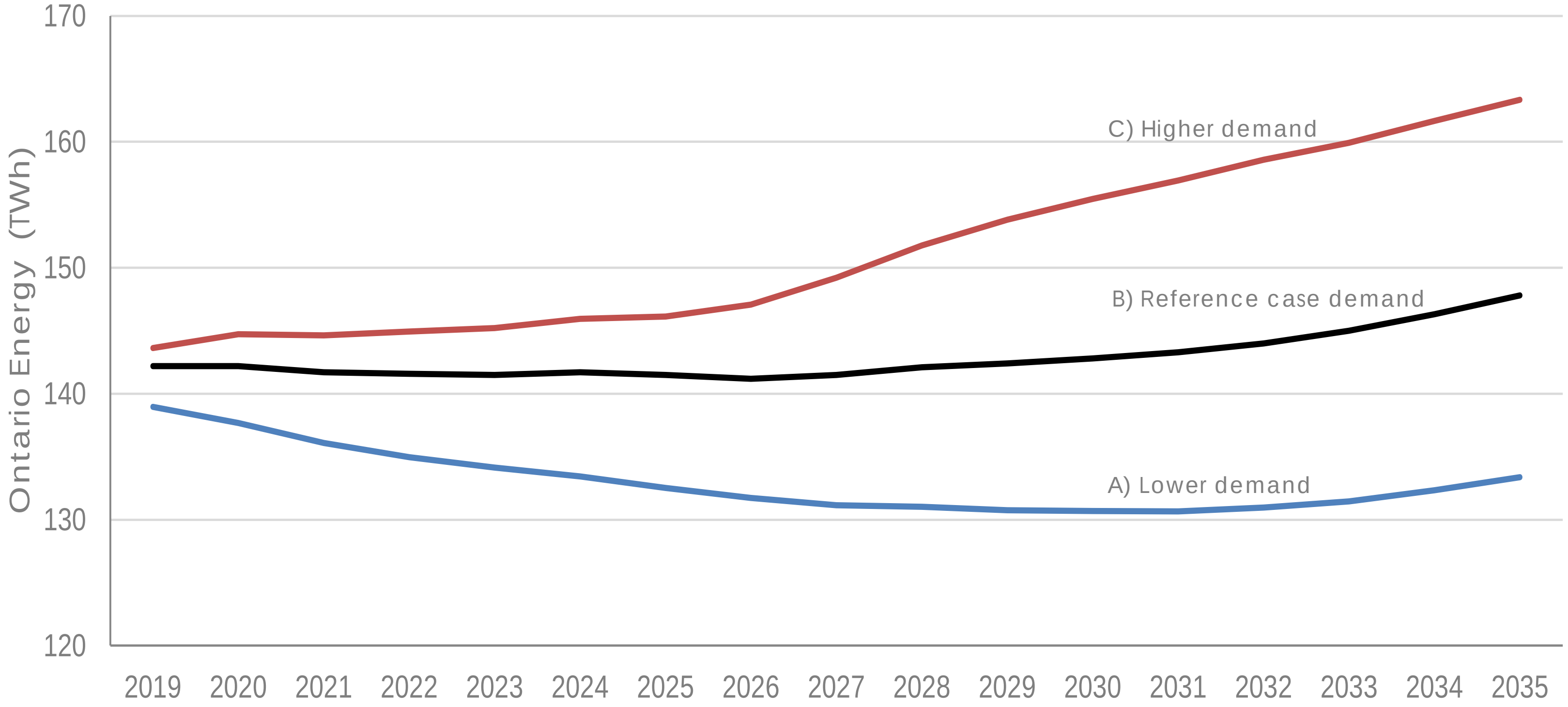
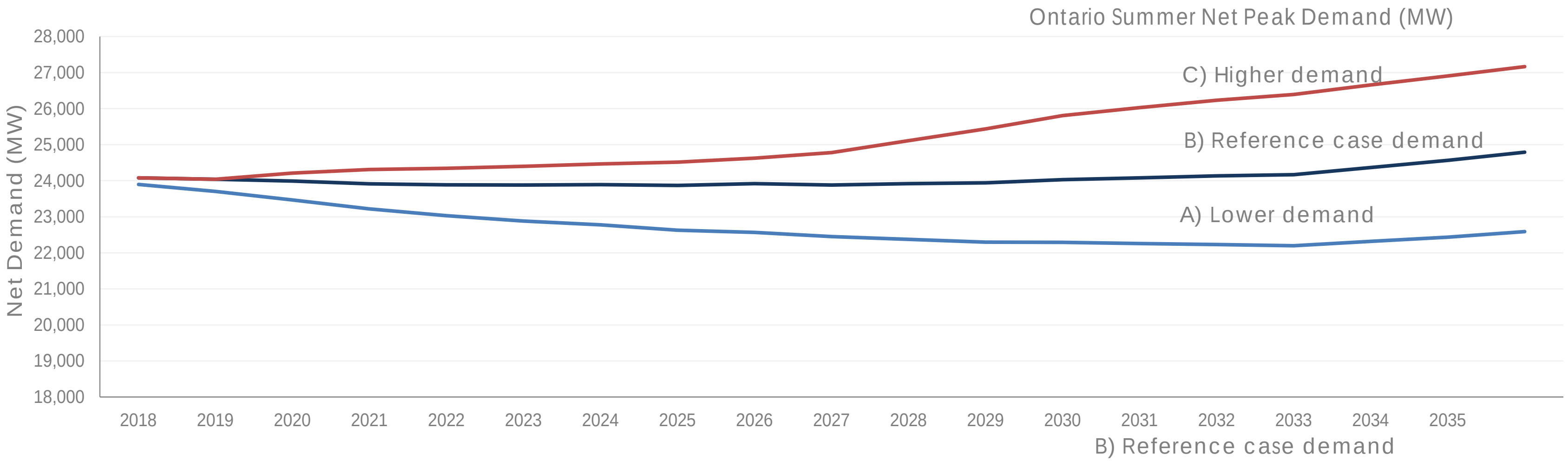
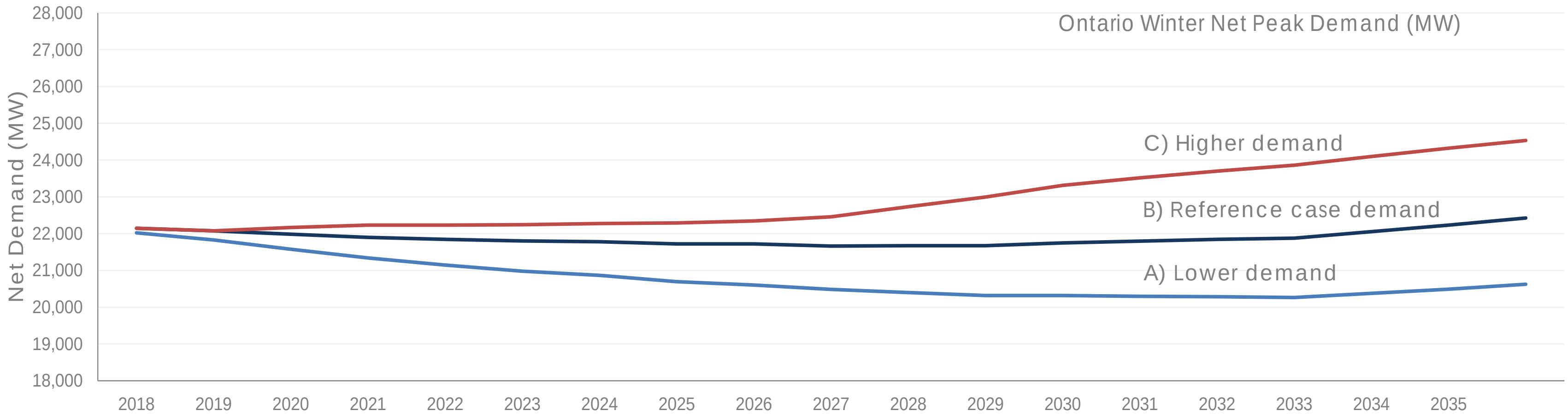
Demand outlooks: Energy demand

- Uncertainties affect the energy demand forecast. Besides the reference case, a lower and a higher demand energy forecast are shown.



Demand outlooks: Summer and Winter Peak





The above demand outlooks reflect 1,000 MW of ICI in the summer at the time these outlooks were developed. The current impact of ICI is estimated to be 1,400 MW.

Uncertainties impacting demand

Various uncertainties will impact the demand outlook. The current economic outlook indicates that the downside uncertainties outweigh the upside uncertainties.

Uncertainty	Details	Change in Demand	Relative Impact
Trade barriers on various industries	Tariffs on Aluminium, Iron and Steel, and potentially the Auto sector will have a negative impact on load. Ripple effects of these tariffs could cascade throughout the economy.	Down	*Medium*
Impact of Industrial Conservation Initiative	Changes to ICI (reducing or increasing eligibility) and rates structure will play a significant role in forecasting demand.	Up or down	*Medium to High*
Heat pumps	Air Source Heat Pump and Ground Source Heat Pump programs funded through GreenON are closed. It is less likely that significant heating fuel switching is going to happen in the near and mid-term.	Down	*Small*
Other programs or policies that affect demand	There are a myriad of programs/policies that could change the demand outlook. These include conservation frameworks/targets, electrification, and GHG reduction	Up or Down	*Small to Medium*
Other economic uncertainties	Demand forecasts are based on economic growth and population projections. Unexpected events like recessions or trade barriers could lead to lower demand.	Up or Down	*Small to Medium*
Growth in industrial and agricultural sectors	Projected rapid greenhouse expansion in Leamington (500+MW of winter load growth expected in 2020) and development of the Ring of Fire will drive the load up in local areas.	Up	*Small to Medium*
Distributed energy resources (DER)	Output from DERs offsets the need for supply from the province-wide system. This is creating new opportunities and challenges for the electricity sector	Down	*Small to Medium*

Future key drivers for electricity demand

Factors which may cause demand to decrease:

- Tariffs on aluminium, iron and steel and auto sector will have a negative impact on industries.
- Flexible working environments (Example, tele-commuting, mobile work stations, etc.)
- Lower household affordability, changing cultures resulting in younger generations staying at home for longer.
- Dramatic cost decrease of new efficient technologies increases penetration of these uses. For example, massive use of LED light bulbs.

Factors which may cause demand to increase:

- Less conservation than anticipated
- Additional mining/smelting and/or chemical growth
- Disruptive uses of electricity
- Commercial data farm/server growth greater than expected
- Increased greenhouse agriculture in southern Ontario

Demand forecasting next steps

- Update of the 20-year long-term demand forecast will be in progress, to be released in 2019. Will be updated annually

- Scenarios need to be developed to address the risk of change in demand and to provide more context for planning. Factors to consider include:

  ✓ Distributed energy resources and behind-the-meter generation
  ✓ Rooftop solar, net metering and energy storage
  ✓ The Industrial Conservation Initiative (ICI)
  ✓ Others?

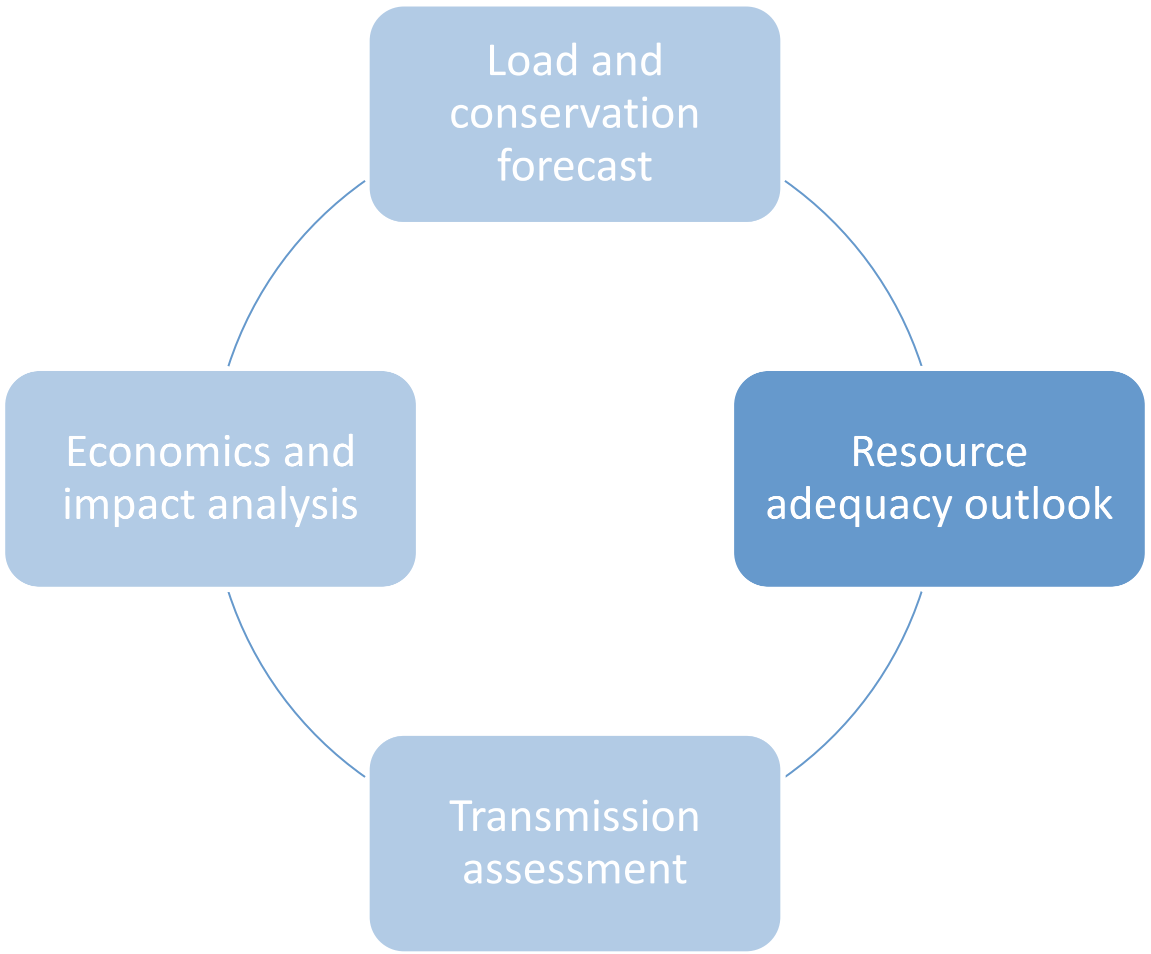
Questions

- What other key factors, uncertainties, scenarios, indicators, etc. should be considered in the demand and conservation assessment?

- How should we recognize and integrate risks related to the demand and conservation assessment?

- What additional information should the IESO provide to the market?

Bulk system planning process - Resource adequacy outlook

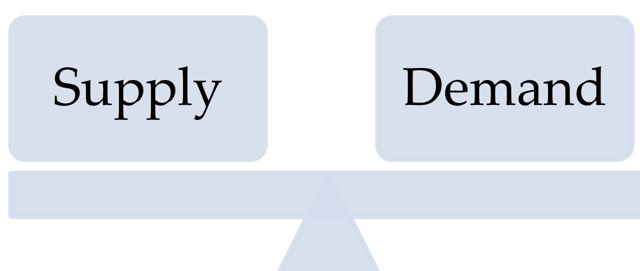


What is resource adequacy?

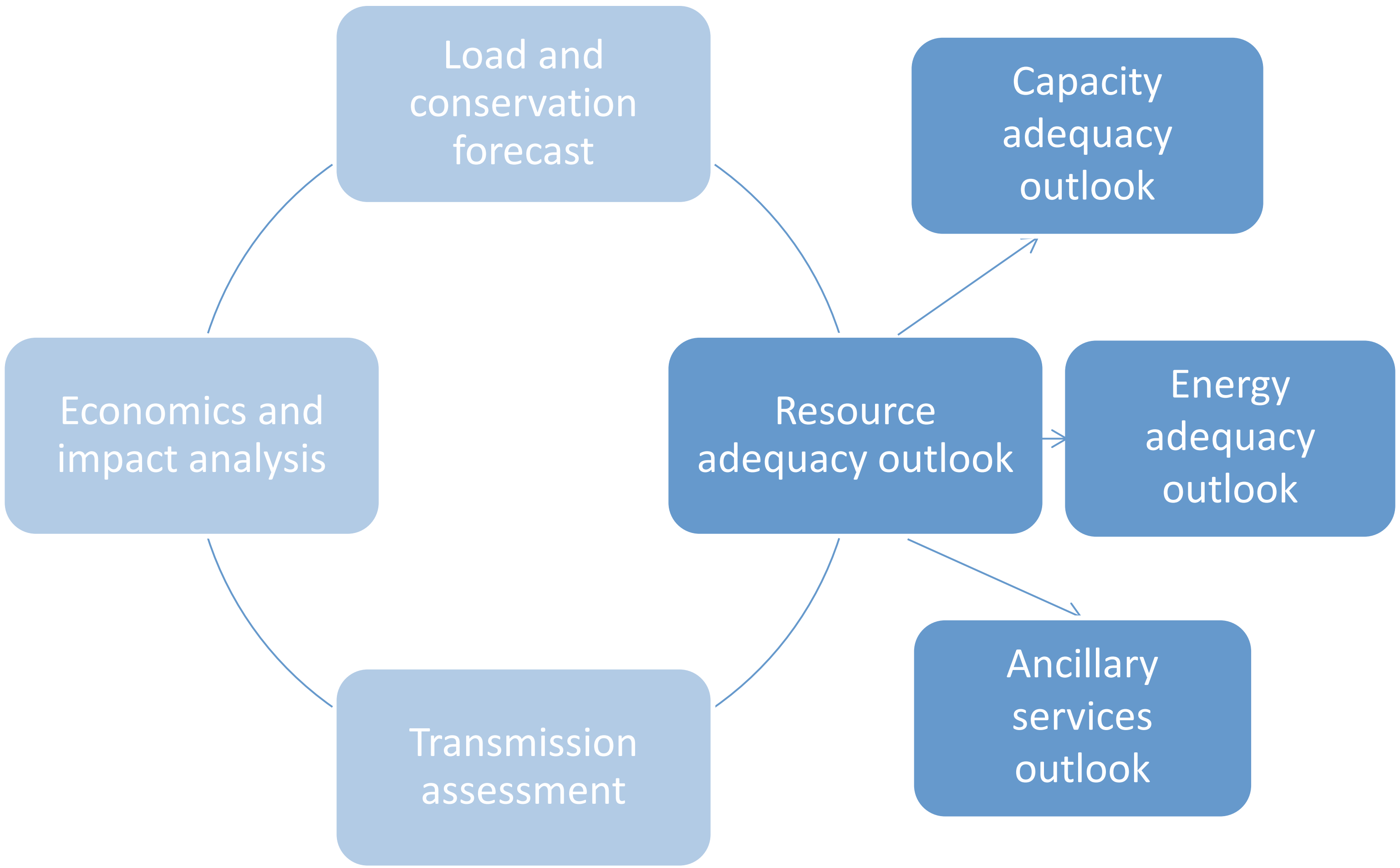
- Adequacy assessments are a way to assess the ability of electricity resources to meet electricity demand at all times, taking into consideration the demand forecast, generator availability, and transmission constraints.

- Adequacy is a cornerstone of reliability and is one of many assessments (with operating security as another) within the electricity system planning process.

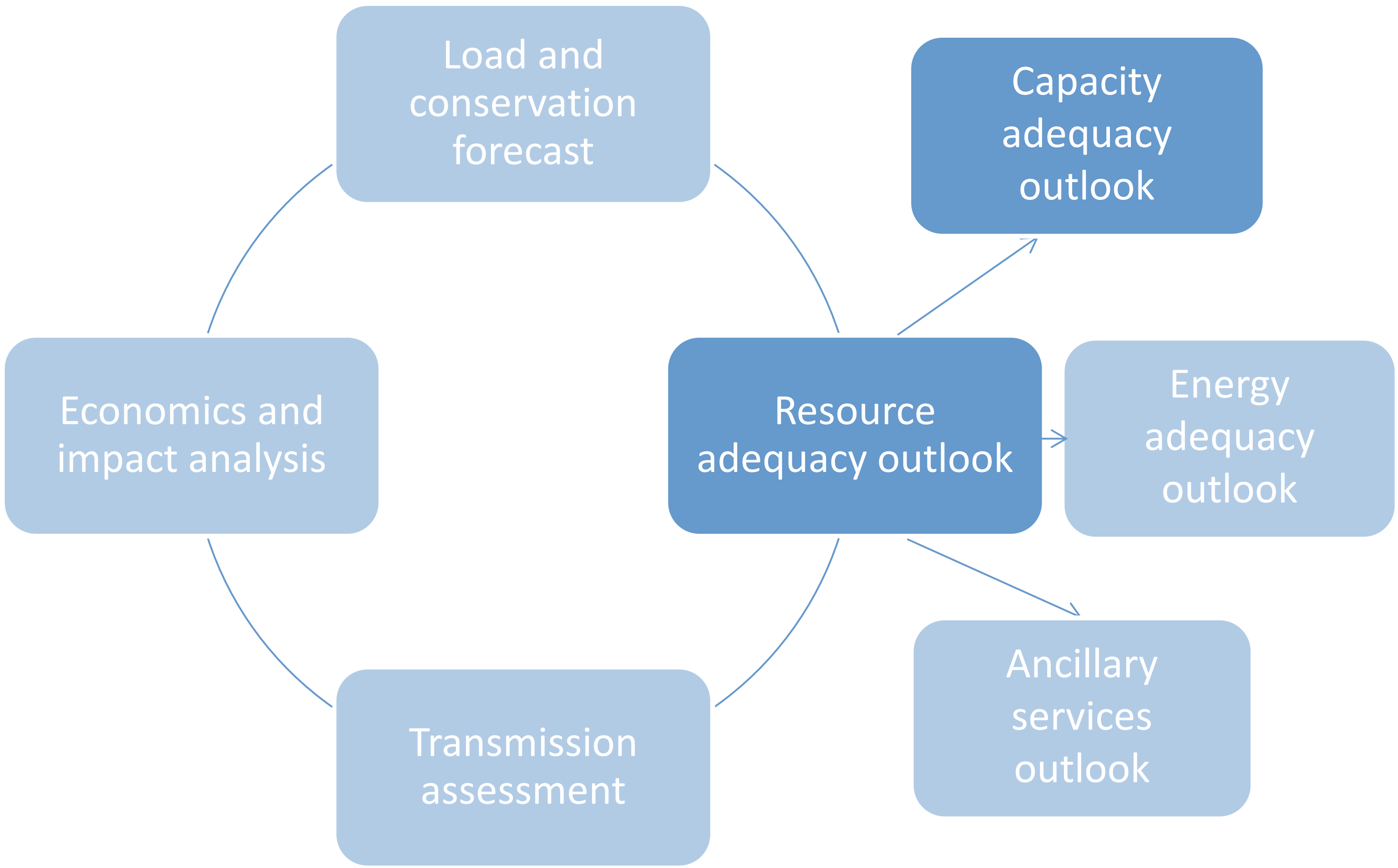
- Adequacy studies are performed to:
  - Determine supply/demand balance.
  - Identify amount, timing and duration of capacity needs.
  - Provide guidance on the scope and timing for resource acquisition and investment decisions.
  - Provide recommendations on capacity export decisions.



The resource adequacy outlook is the outlook for reliability services and the capability to meet system needs over the planning outlook

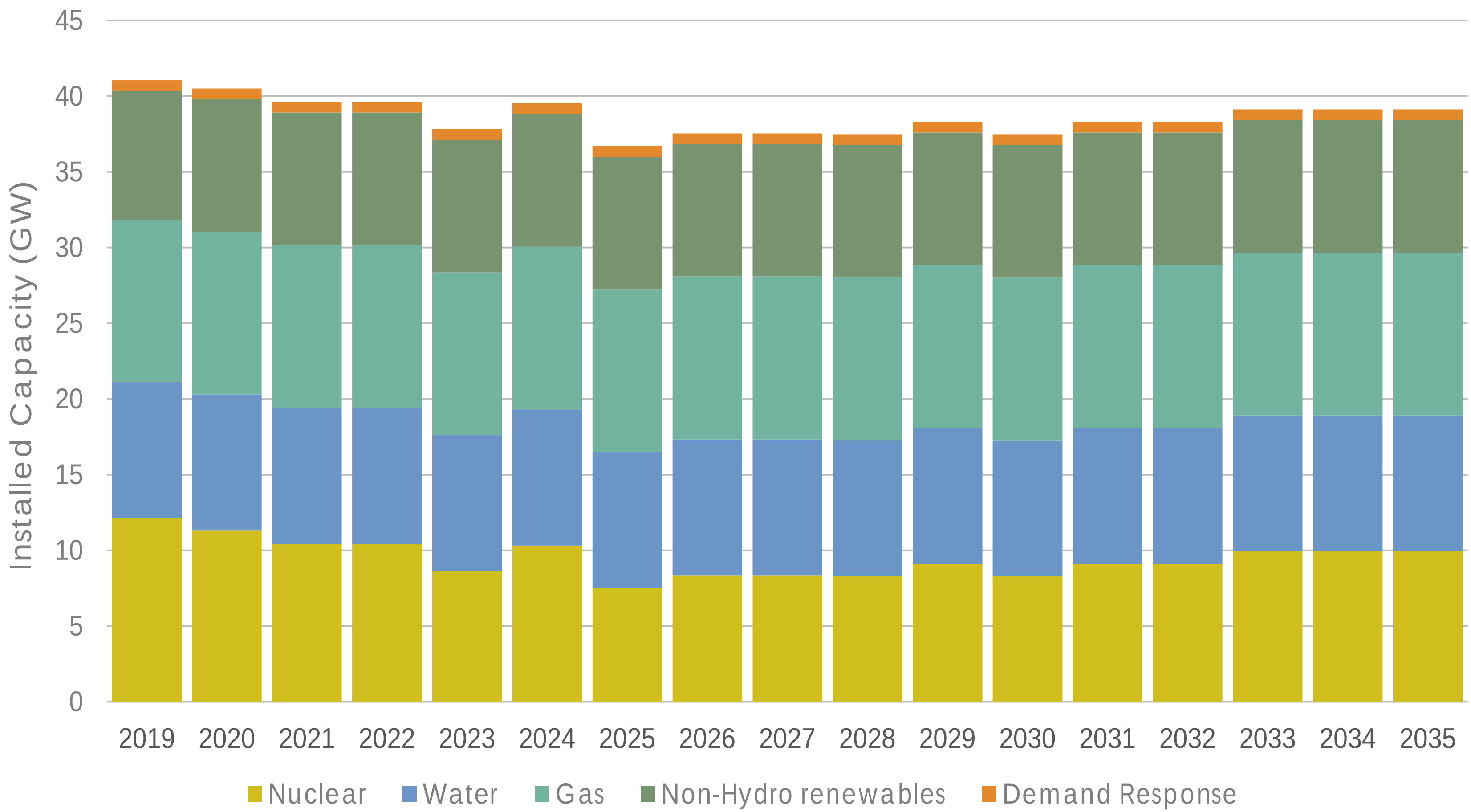


Capacity Adequacy Outlook



Ontario installed capacity outlook by fuel type

- Installed capacity ranges between 37 GW and 41 GW over the 2019 through 2035 planning outlook.
- Fuel share of current supply mix installed capacity is relatively unchanged over the planning outlook: nuclear averages 25% of the mix, waterpower 23%, non-hydro renewables 22%, gas 28%, and demand response 2%.
  - The supply mix share could evolve as new resources enter the market or as existing resources exit the market.



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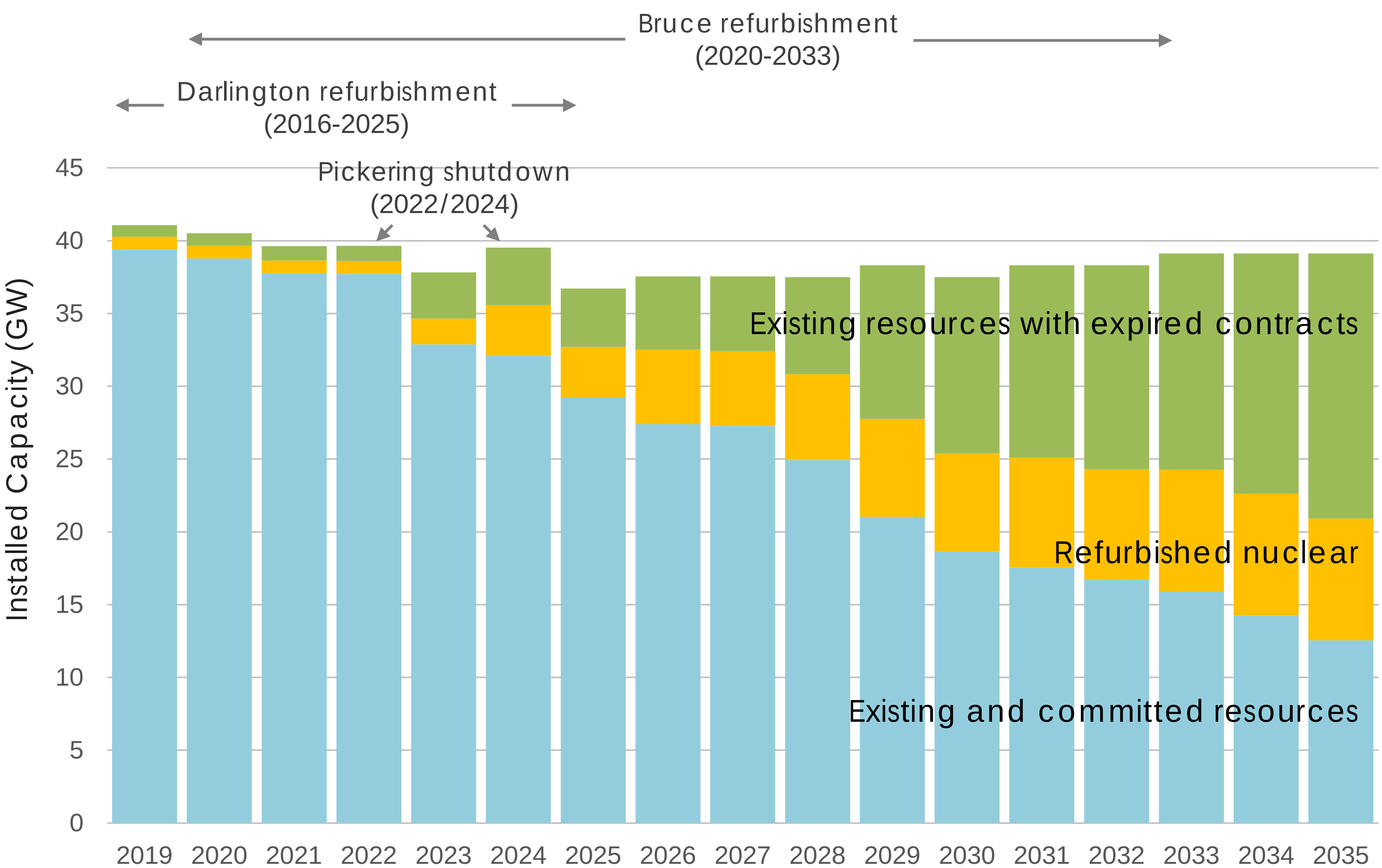
Outlook for supply resources

- Reference Outlook reflects the continued availability of electricity resources post-contract expiration.
  - Assumes mechanisms would be in place to allow existing resources to continue to provide reliability services as required, primarily through the electricity market, including an incremental capacity auction.
- Market participant data reflects information as of Q1-2018, with contract data as of January 2018.
- Continuation of current demand response levels.
- Pickering operations to 2022 (six units) and 2024 (four units).
- Darlington refurbishments between 2016 and 2025.
- Bruce refurbishment between 2020 and 2033 per the 2015 Amended Bruce Power Refurbishment Implementation Agreement.
- Closure of Thunder Bay GS in July 2018.
- Cancellation of 758 pre-NTP FIT 2-5 and pre-KDM LRP contracts and White Pines Wind Farm contract.
- Amended Hydro Quebec supply agreement which sees Ontario provide Quebec 500 MW of capacity in the winter to 2023. Quebec to provide Ontario 500 MW of capacity in the summer in any one year of Ontario’s choosing, prior to 2030. Also includes energy cycling.

Ontario installed capacity outlook by commitment type

- Significant resource turnover is expected in the coming years driven by nuclear retirements and refurbishments and contracted facilities reaching end of commercial agreements.



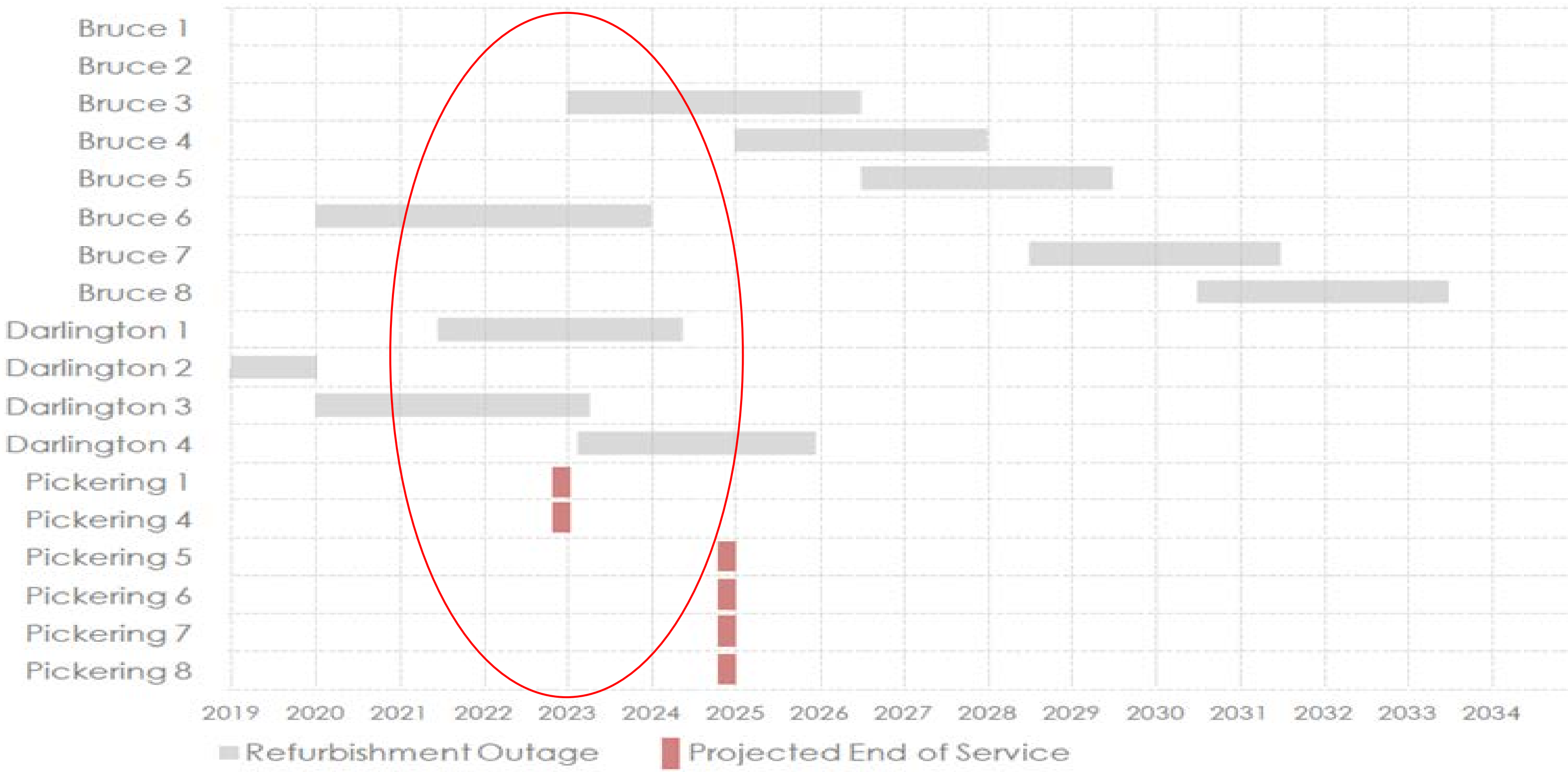
Demand response auction

- DR auction is used to acquire DR resources, and will transition into the ICA.
- The annual DR auction, started in December 2015, has resulted in increased participation and cleared capacity as well as lower clearing price for capacity.
- The most recent DR auction, occurred December 2017, included a mix of residential, commercial, and industrial DR resources.
  - 571 MW capacity cleared for summer 2018 and 712 MW capacity cleared for the following winter. The annual clearing price is $76,000/MW.

Season	Summer	Winter
	(May 01, 2018 - Oct 31, 2018)	(Nov 01, 2018 - Apr 30, 2019)
Availability window (business day only)	Hour Ending (HE) 13 to HE 21	HE 17 to HE 21
Cleared capacity (MW)	570.7	712.4
Clearing price ($/MW-day)	318	317

Nuclear refurbishment and retirement schedule

- Nuclear refurbishment and retirement programs are critical to maintaining reliability.
- Many refurbishment outages in a relatively short period of time, sometimes in parallel.
- Period between 2021 and 2025 sees most activity as between 3 to 4 units are on refurbishment outage and Pickering reaches end of life.
- Delays with the refurbishment of one unit could have ripple effects causing delays on subsequent units.
- Need to continue to work with nuclear operators to plan and coordinate outages, along with coordinating with other generation and transmission outage plans, to minimize impacts on adequacy.



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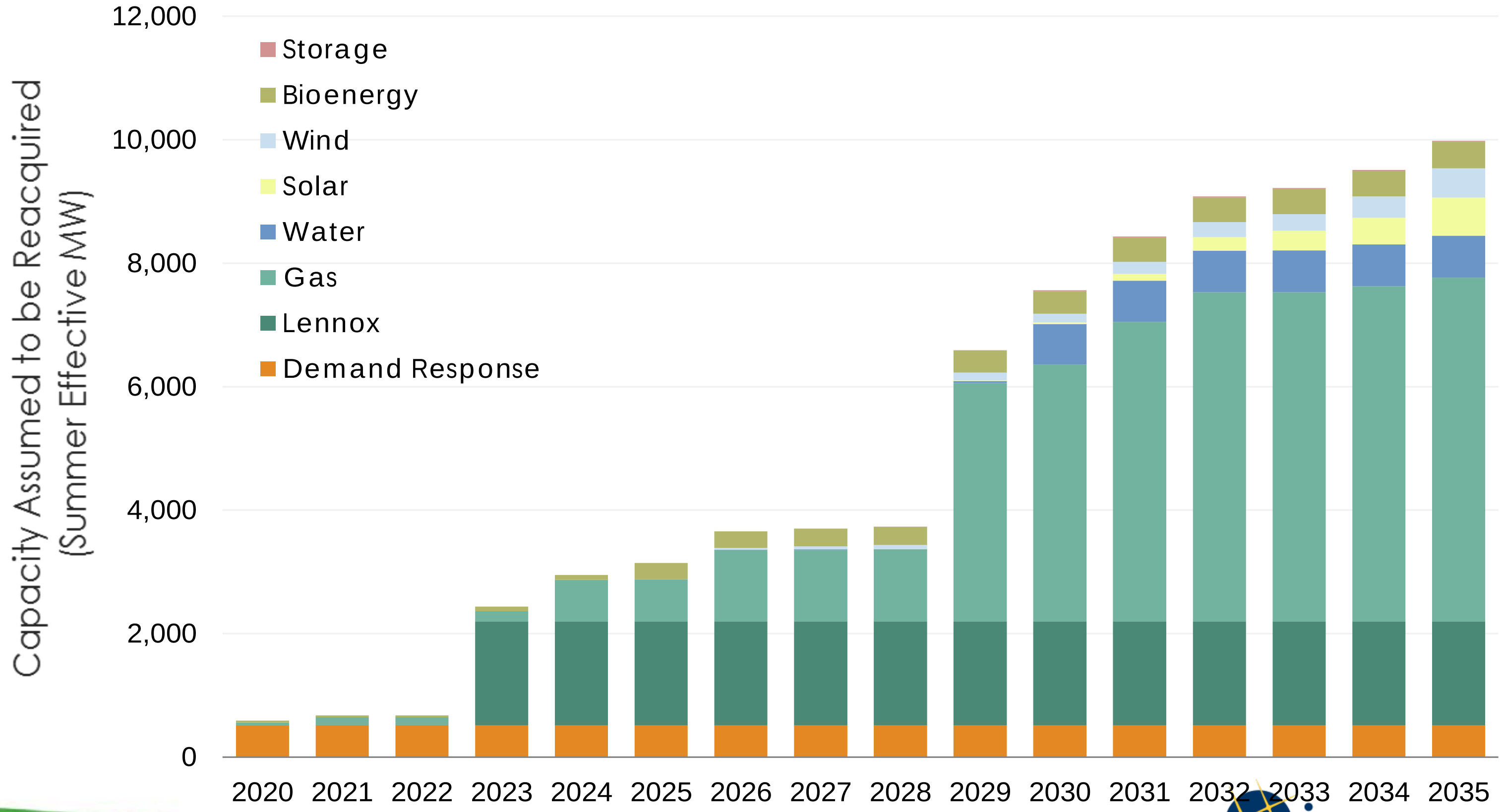
Resources with expired contracts

- Approximately 2,000 contracts representing 18,000 MW of installed capacity - which is equivalent to about 10,000 MW of available capacity at time of peak – will expire by 2035.
  - Expectation is that reliability products are continued to be provided by those existing resources.
- Although 21,000 microFIT contracts reach term, they represent a significantly smaller share of installed capacity totalling about 190 MW. There is uncertainty in the availability of microFIT resources post contract expiration.
- About 600 MW available peak capacity expires in 2020 growing to 2,400 MW in 2023 following the expiration of Lennox's contract. This grows to 6,600 MW by 2029 as gas facilities reach contract term.



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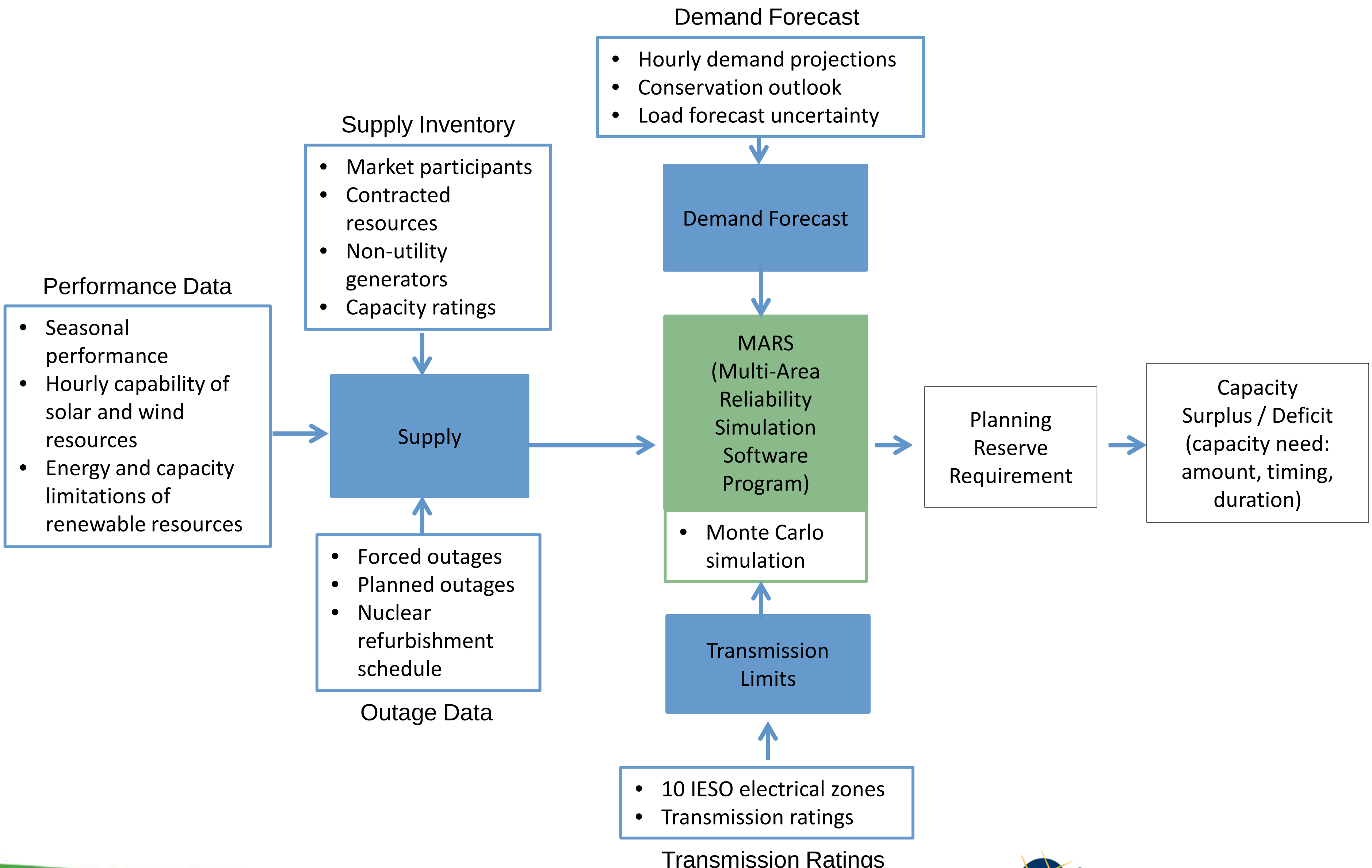
Resource adequacy assessment process



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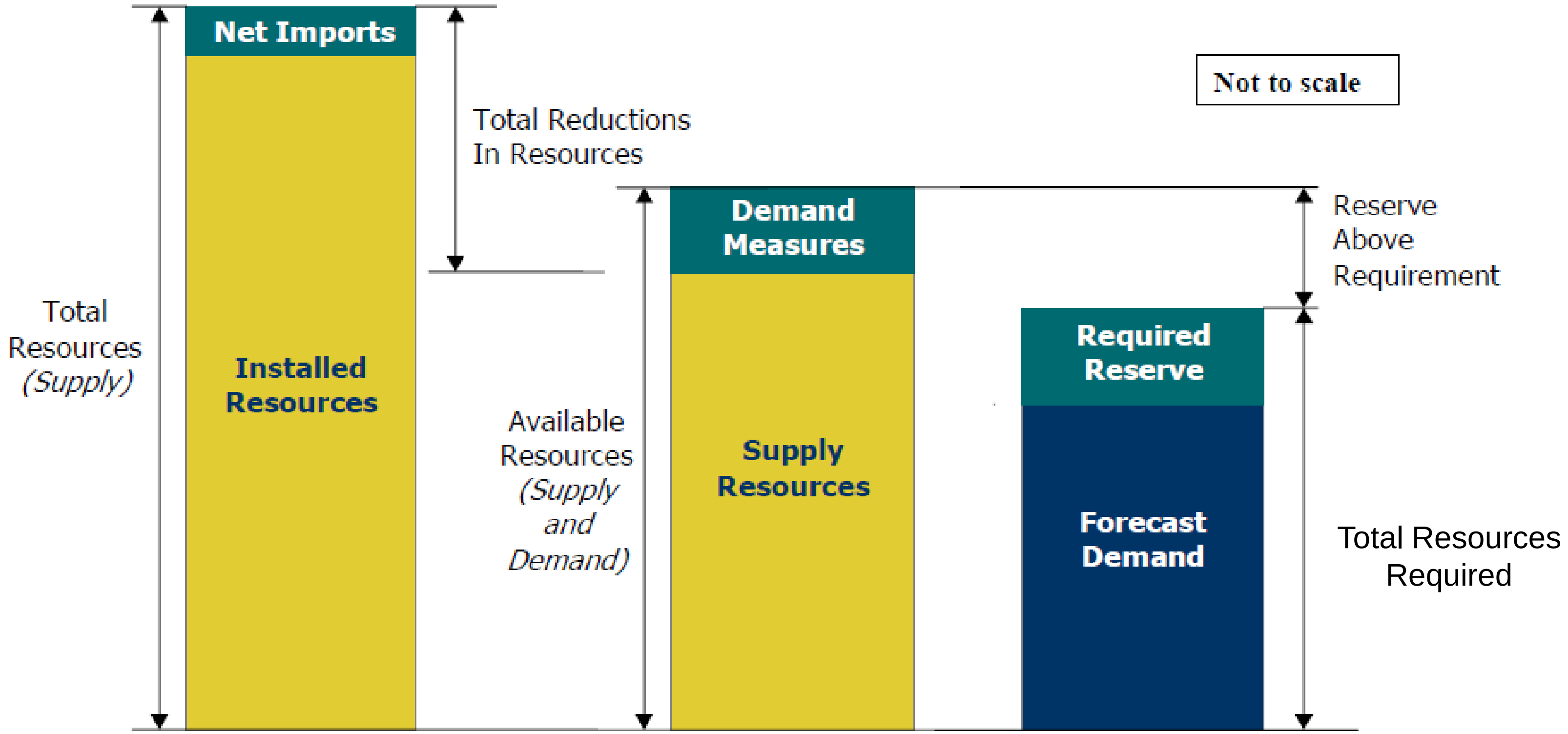
Identifying capacity requirements



- The Total Resources Required is the Ontario demand plus the required reserve.
- If the Total Available Resources is greater than the Total Resource Requirement, then we have Reserve Above Requirement (capacity surplus).
- If the Total Available Resources is less than the Total Resource Requirement, then we have Reserve Below Requirements (capacity deficit).

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Assessing the planning reserve requirement

- The reserve requirement is the amount of supply above forecasted peak demand that must be planned for to ensure there is sufficient supply to meet demand under a range of demand side and supply side risks.
  - It reflects the characteristics of the demand and supply mix. Changes to the supply mix can change the amount of reserve required.
  - Determined by performing a probabilistic assessment of anticipated capacity and forecast load.

- Reliability standards - NPCC Directory #1 and ORTAC Section 8 - require that the IESO maintain enough capacity such that the loss of load expectation (LOLE) – i.e. the likelihood of supply falling short of demand – is no greater than 0.1 days/year across the range of demand/supply side risks.
  - The 0.1 day/year LOLE criterion is sometimes characterized as “one day in ten years”.

- Risks considered in the IESO’s assessment include load forecast uncertainty due to weather and generator forced outages per NPCC requirements.
  - NPCC also allows for consideration of other risks deemed appropriate by the System Planner.
  - In addition to load forecast uncertainty and generator outages, the IESO includes an incremental planning reserve required to cover wind variability and nuclear refurbishment performance risks (impact of nuclear refurbishment return-to-service delays and nuclear unit performance degradation just before and after refurbishment).

Reserve assessment – model and key inputs

- The IESO uses General Electric's Multi-Area Reliability Simulation (GE-MARS) program to conduct resource adequacy assessments. It is a probabilistic simulation tool that is widely used in the industry.

- Key input parameters include:
  - Hourly demand projections.
  - Load forecast uncertainty driven primarily by weather variability.
  - Capacity ratings of resources including demand measures.
  - Forced and planned outages.
  - Energy and capacity limitations of renewable resources.
  - Hourly capability of solar and wind resources.
  - 10 IESO electrical zones transmission limits.
  - Nuclear refurbishment schedule.

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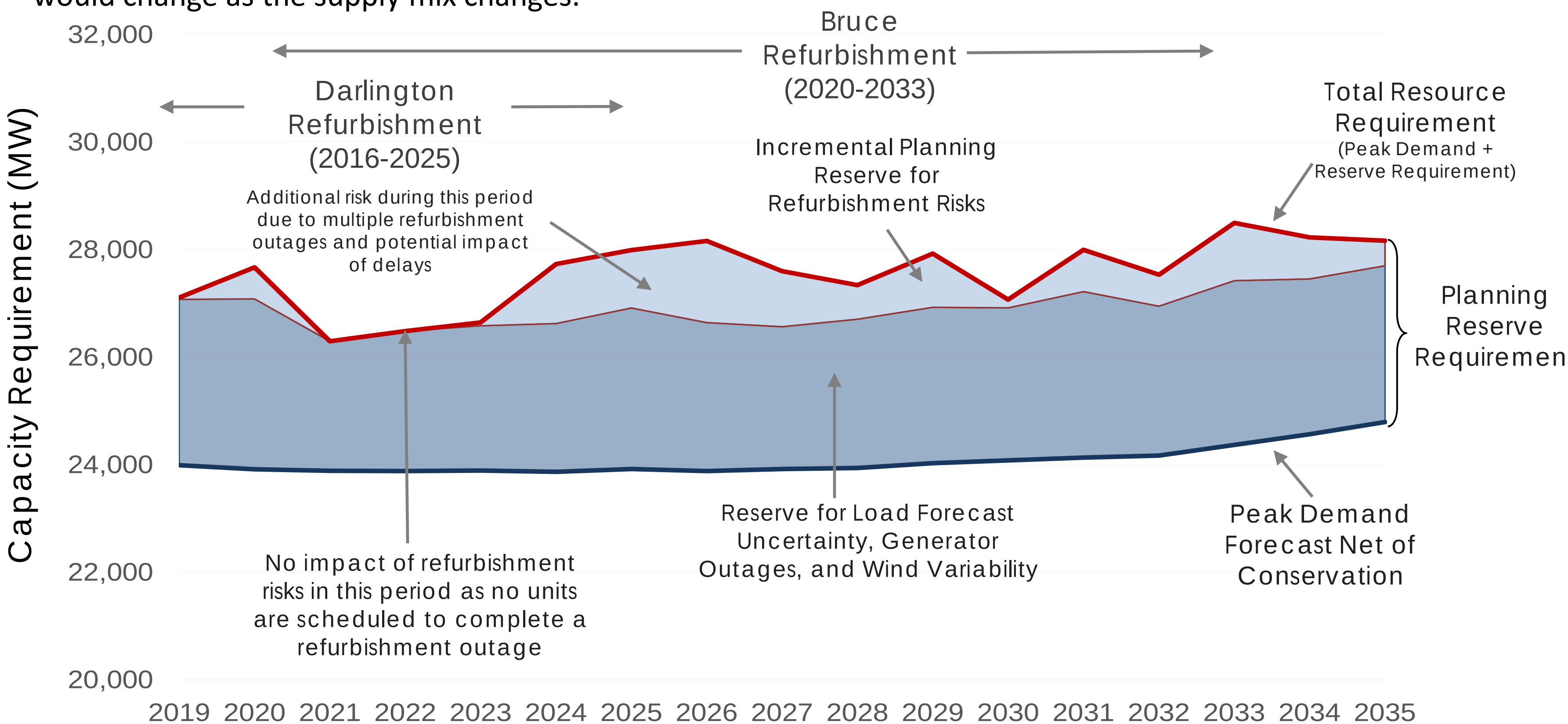
The planning reserve requirement

- The planning reserve reflects load forecast uncertainty, generator forced outages, wind variability, and nuclear performance uncertainty.
- Year-to-year variations in total requirements are a function of the availability of resources in each year and the likelihood of those resources being available to meet electricity demand.
- Changes to the supply mix would affect the amount of reserve required. Thus, the total resource requirement would change as the supply mix changes.



- The IESO publishes the reserve requirement for the next 5 years annually in the Ontario Reserve Margin report.

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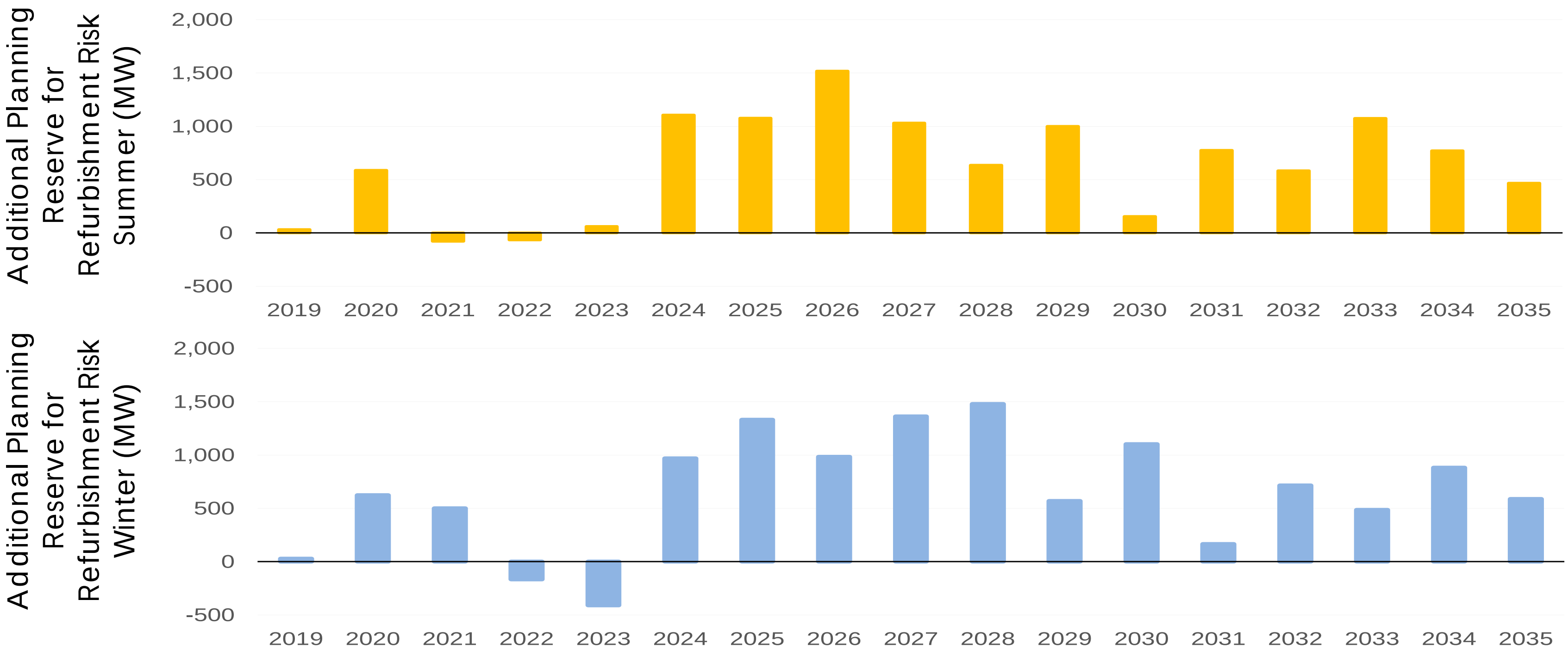
Incremental planning reserve required to cover refurbishment performance risk

- Additional reserve is carried to reflect each year's estimated risk of refurbishment return-to-service delays and pre/post-refurbishment performance degradation.
- The IESO expects to have a better understanding of the nuclear refurbishment schedules by 2020 and will continue to refresh outlooks and associated impact on additional planning reserve as new information becomes available.



Note: The incremental planning reserve is negative in a few years because in some scenarios, the delay of return to service in one unit causes the refurbishment start of subsequent units to be deferred, resulting in fewer units on outage overall than under scenarios with no delays. As a result, more units could potentially be available, reducing the overall reserve requirement in those years.

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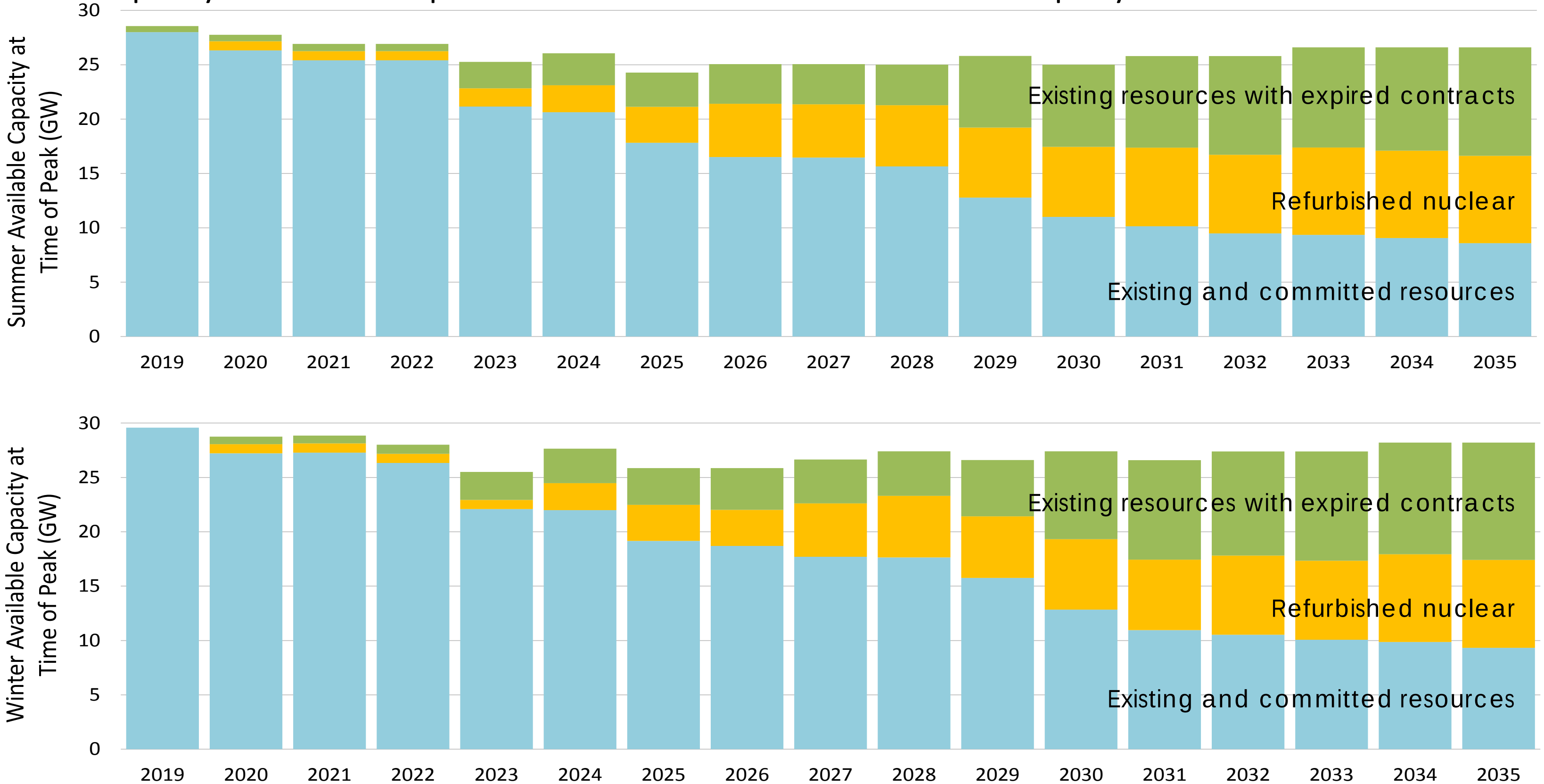
Available capacity at time of peak

- Previous figure illustrated installed supply outlook.
- Resources do not operate at their maximum capacity when needed. Capacity availability varies by resource type and by season.
- Available capacity at the time of peak demand is assessed to determine adequacy.

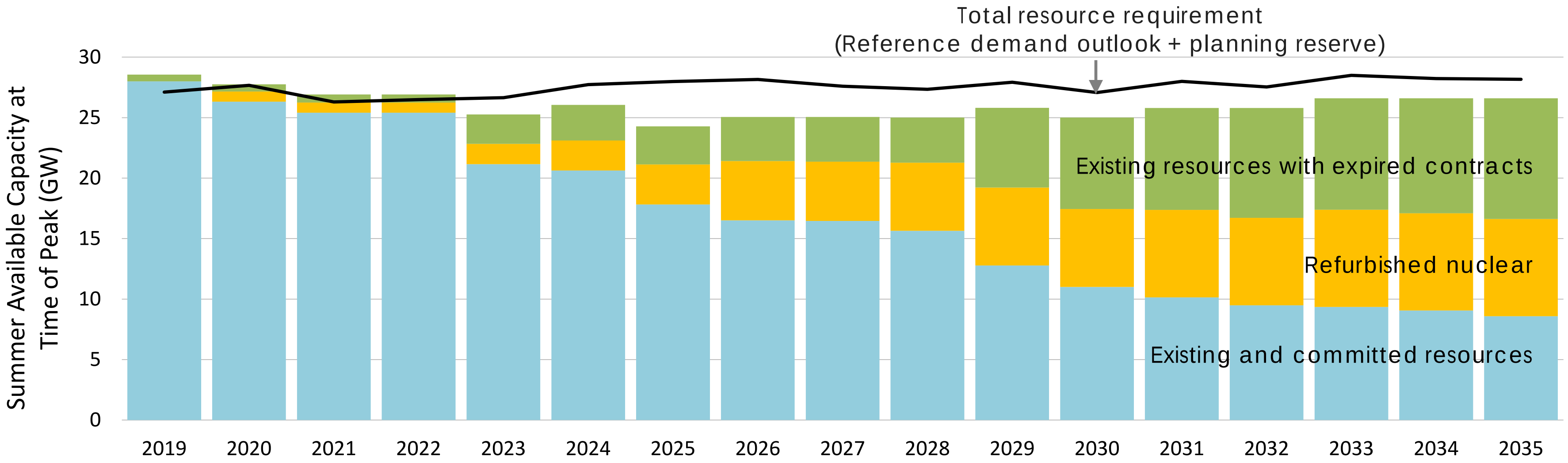


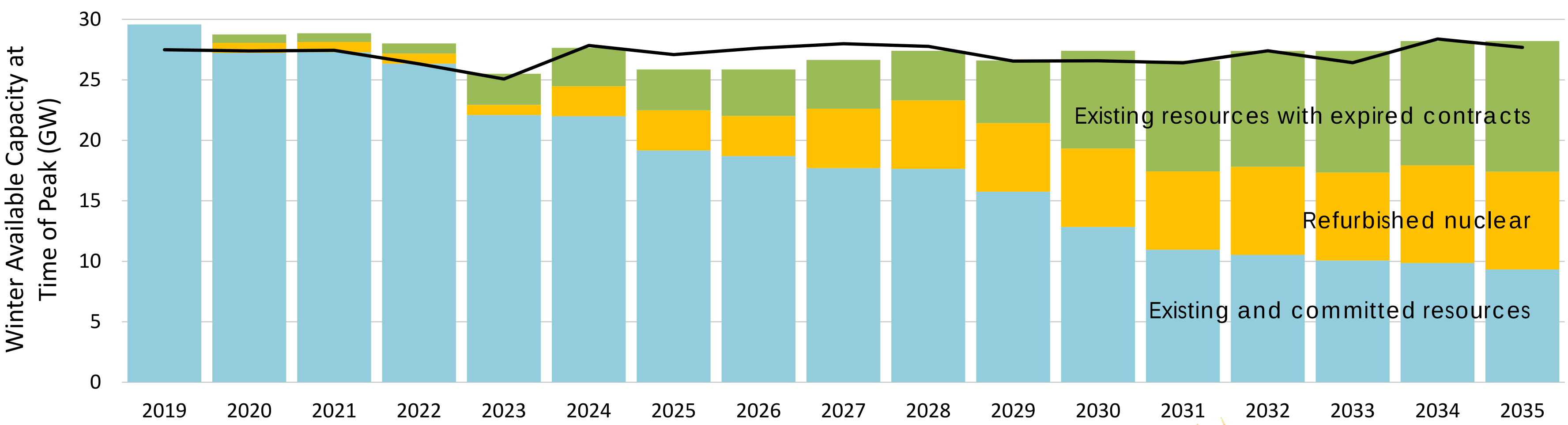
Current Planning Assumptions	Bioenergy	DR	Gas	Nuclear	Solar	Water	Wind
Summer Available Capacity, % of Installed	92%	90%	80%	93%	33%	68%	11%
Winter Available Capacity, % of Installed	92%	90%	86%	94%	5%	74%	27%

Note: Existing resources with expired contracts includes existing DR auction capacity.

Available capacity compared to the total resource requirement

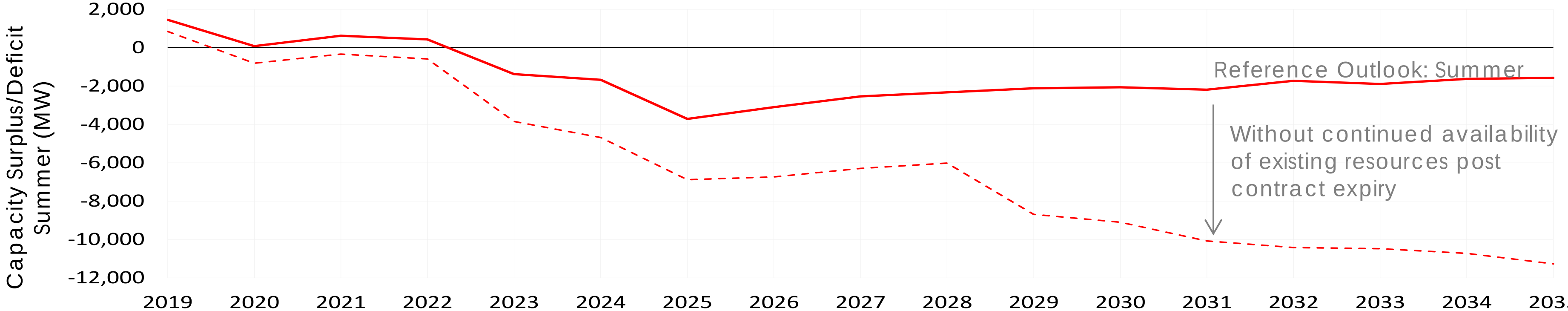
- The total resource requirement is compared to the resources available at the time of peak demand to determine the extent to which there is a capacity surplus or deficit (i.e. need for resources).

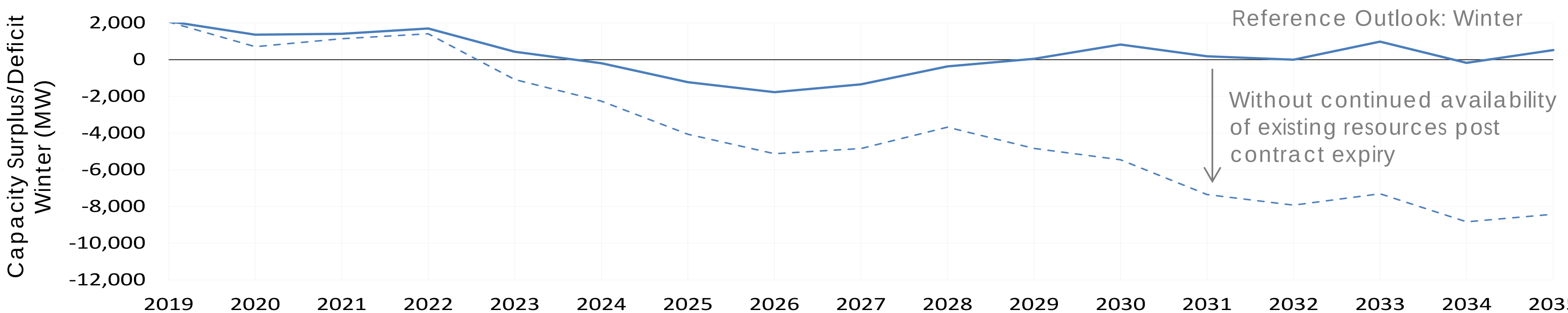




Capacity adequacy outlook (surplus/deficit): Reference demand outlook, with continued availability of existing resources with expiring contracts

- In the reference outlook, a need for new capacity of about 1,400 MW emerges in 2023. The need increases to 3,700 MW in 2025 before plateauing to about 2,000 MW over the long-term. This assumes that capacity from existing resources continues to be available post contract which helps to defer and reduce the need for new capacity.
- Long-term capacity need primarily driven by Pickering retirement.
- Continuing to acquire capacity from demand response through the auction can meet needs to 2023.

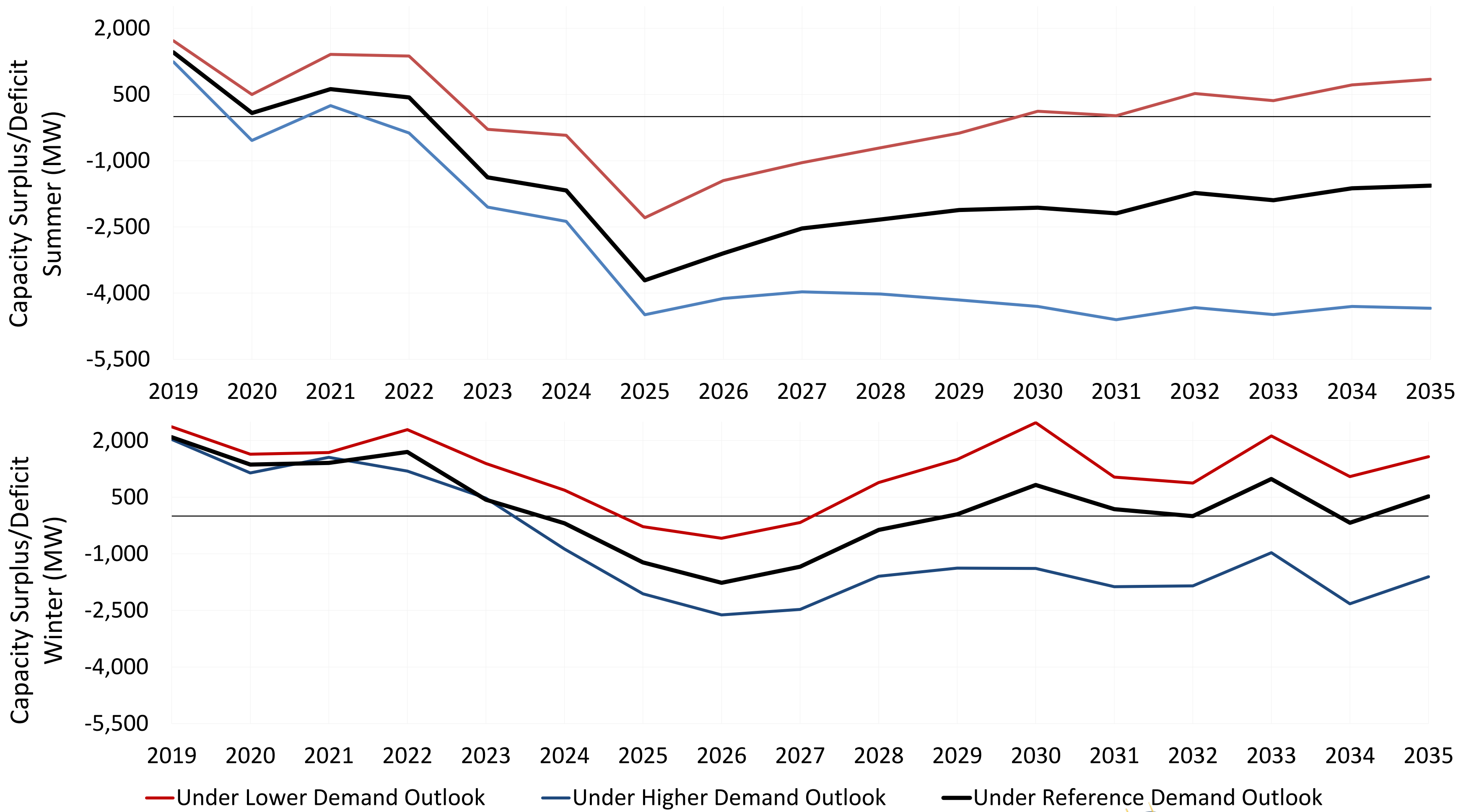




Capacity Surplus (+)/Deficit (-) (MW)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer Adequacy: Reference Outlook	1,454	81	622	433	-1,377	-1,673	-3,711	-3,099	-2,536	-2,330	-2,118	-2,065	-2,192	-1,729	-1,895	-1,625	-1,566
Summer Adequacy: Reference Outlook Without Existing Res.	847	-811	-335	-583	-3,844	-4,686	-6,878	-6,736	-6,292	-6,018	-8,689	-9,096	-10,077	-10,418	-10,475	-10,724	-11,273
Winter Adequacy: Reference Outlook	2,091	1,364	1,408	1,698	435	-192	-1,229	-1,770	-1,343	-366	47	825	184	-2	983	-176	523
Winter Adequacy: Reference Outlook Without Existing Res.	2,060	710	1,143	1,410	-1,085	-2,263	-4,063	-5,124	-4,838	-3,675	-4,833	-5,451	-7,344	-7,921	-7,306	-8,834	-8,419

Capacity adequacy outlook (surplus/deficit): Across demand outlook scenarios, with continued availability of existing resources with expiring contracts

- Capacity needs can be lower or higher depending on the demand outlook.
- Under a lower demand outlook, the need for new resources becomes temporary in duration.



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Interjurisdictional cooperation through the use of non-firm import capacity

- Traditionally, Ontario has planned to be self-sufficient.

- Non-firm imports represent the capacity contribution of expected flows through Ontario's interconnections at times of system need.

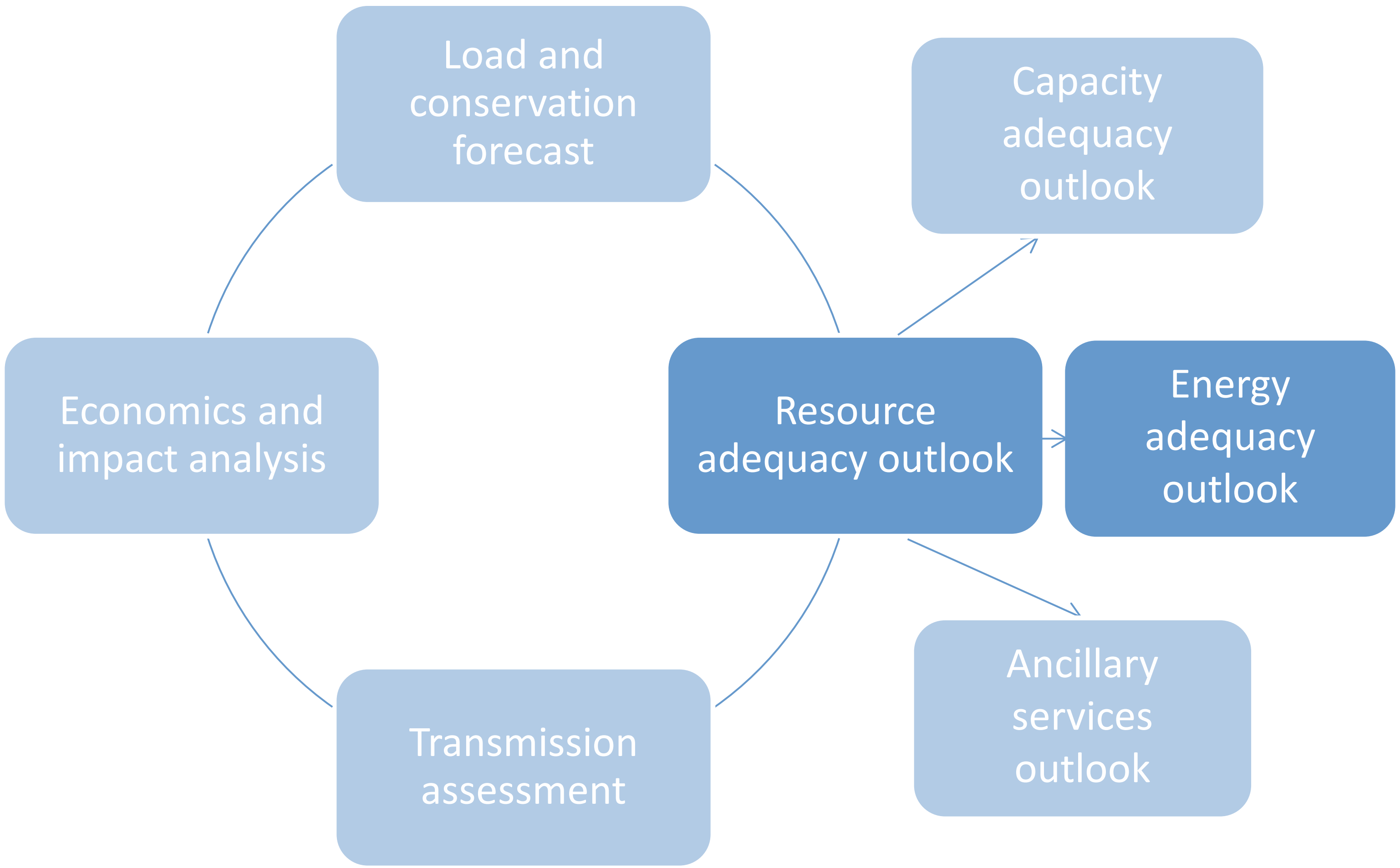
- Many North American jurisdictions (PJM, MISO, NYISO, ISO-NE, etc.) rely on non-firm imports for capacity to contribute towards meeting their capacity adequacy requirements.
  - Supported by NPCC interconnection assistance reports in the near-term.
  - At various times, NERC has raised concern about shrinking reserve margins - including the northeast part of North America. This should be considered in assessing the amount of non-firm imports to rely upon.

- Ontario's current supply outlook does not consider utilizing non-firm imports to meet capacity adequacy requirements.

- The IESO has been exploring the use of non-firm imports in future resource adequacy assessments while ensuring that reliability is maintained.
  - These benefits, arising from the reduced need to purchase capacity, must be weighed against potential risk to reliability.
  - Similar treatment to internal non-firm resources – there is no obligation to serve load but the market signals a need and market resources respond accordingly.

- We will engage stakeholders on our proposal.

Energy Adequacy Outlook



Energy production and economic dispatch assessments

- The IESO conducts energy production and economic dispatch assessments of electricity resources to give insight into important operational and performance parameters with respect to Ontario's electricity system over the planning period. These include:
  - **Energy adequacy and operability:** To determine whether or not Ontario has sufficient supply to meet its forecast energy demands and to identify any potential concerns associated with energy adequacy and operability.
  - **Electricity imports and exports:** Considers that Ontario is part of an interconnected market and where energy market prices dictate, electricity may be imported into Ontario or exported from Ontario.
  - **Surplus baseload generation:** Extent to which electricity production from baseload facilities is greater than Ontario's demand.
  - **Transmission congestion:** Extent to which resources are bottled due to transmission constraints.
  - **Market price:** An approximation of the Hourly Ontario Energy Price (HOEP).
  - **Electricity sector emissions:** Greenhouse gas emissions from Ontario's electricity generation fleet.

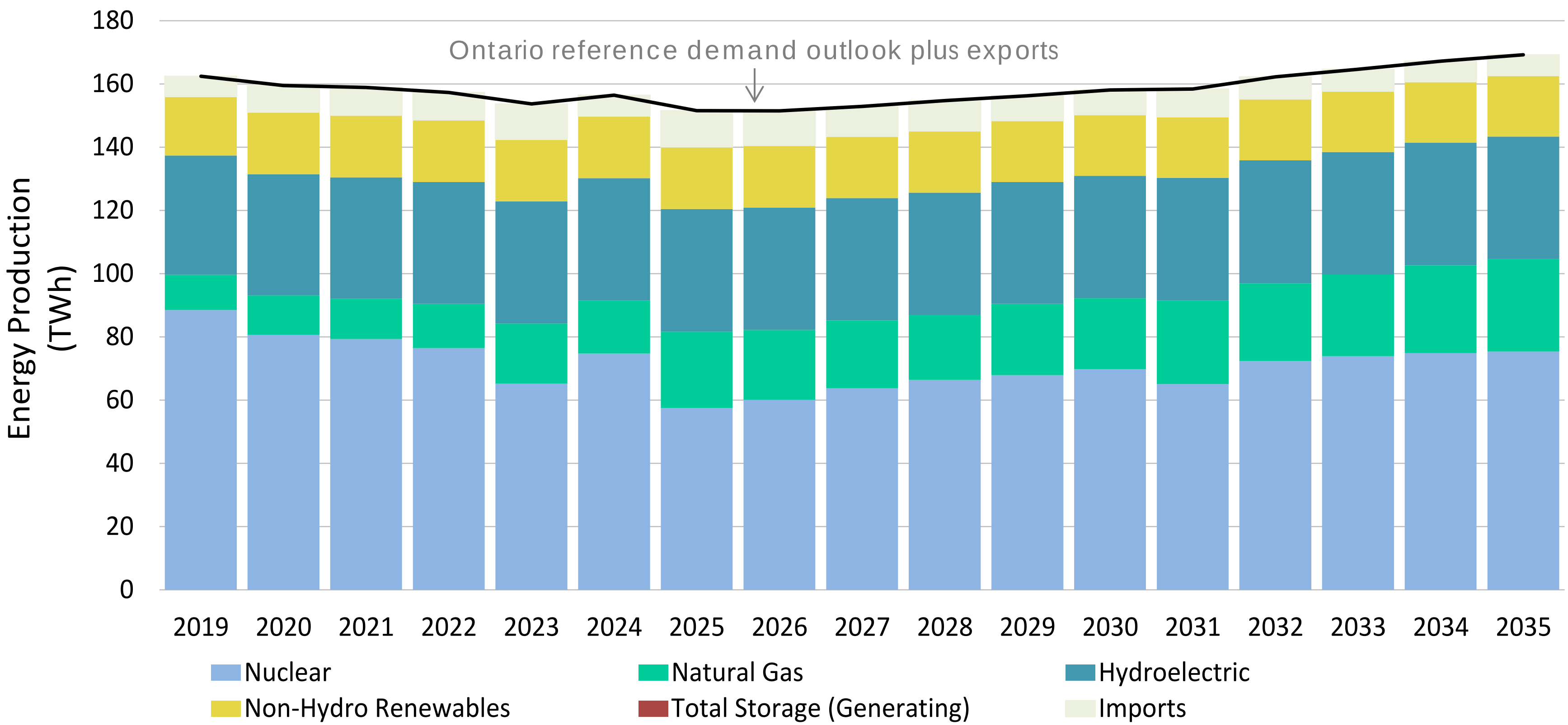
Energy production and economic dispatch assessments

- The IESO uses an energy dispatch model to simulate the energy production and economic dispatch of generation resources in Ontario and neighbouring jurisdictions.
  - A unit commitment and economic dispatch model.
  - An internal load flow program for every hour being simulated — once for unit commitment and again for dispatch — and jointly optimizes energy and transmission flows.
  - The model simulates hourly generation outputs, transmission flows, and economic transactions with adjacent interconnected systems for the study period. It incorporates energy, ancillary services, and multi-regional dispatch using a load flow for market simulations.

- Key input parameters into the energy model include:
  - Information used in the capacity adequacy assessment.
  - Hourly demand forecast for each IESO transmission zone.
  - Performance, operational, and economic characteristics for each Ontario generation unit including maximum capacity, emission rates, outage rates, production profiles, heat rates, minimum up and down times, variable costs and fuel costs.
  - A representation of the Ontario transmission system. All generators are connected to the Ontario transmission system model at their corresponding connection point on the transmission system.
  - Load, generation, and transmission assumptions for interconnected jurisdictions outside of Ontario, including the regions in Northeast Power Coordinating Council, ReliabilityFirst Corporation, and Midwest Reliability Organization. This Eastern Interconnection model enables the assessment of economic power transfers between Ontario and interconnected neighboring jurisdictions.

Energy adequacy outlook

- In the Reference Outlook, which assumes the continued availability of capacity from existing resources, Ontario is expected to have an adequate supply of energy to meet the energy demand forecast throughout the outlook.
- Production from natural gas-fired generation increases following Pickering retirement and during the nuclear refurbishment period.



Imports and exports reflect those that take place due to economic opportunities that exist in the real time energy market and the 2016 Ontario-Quebec Energy Sales and Energy Cycling Agreement. Reflects the continued availability of existing resources post contract expiration. Energy generated from storage is about 0.1 TWh per year between 2020 and 2035.

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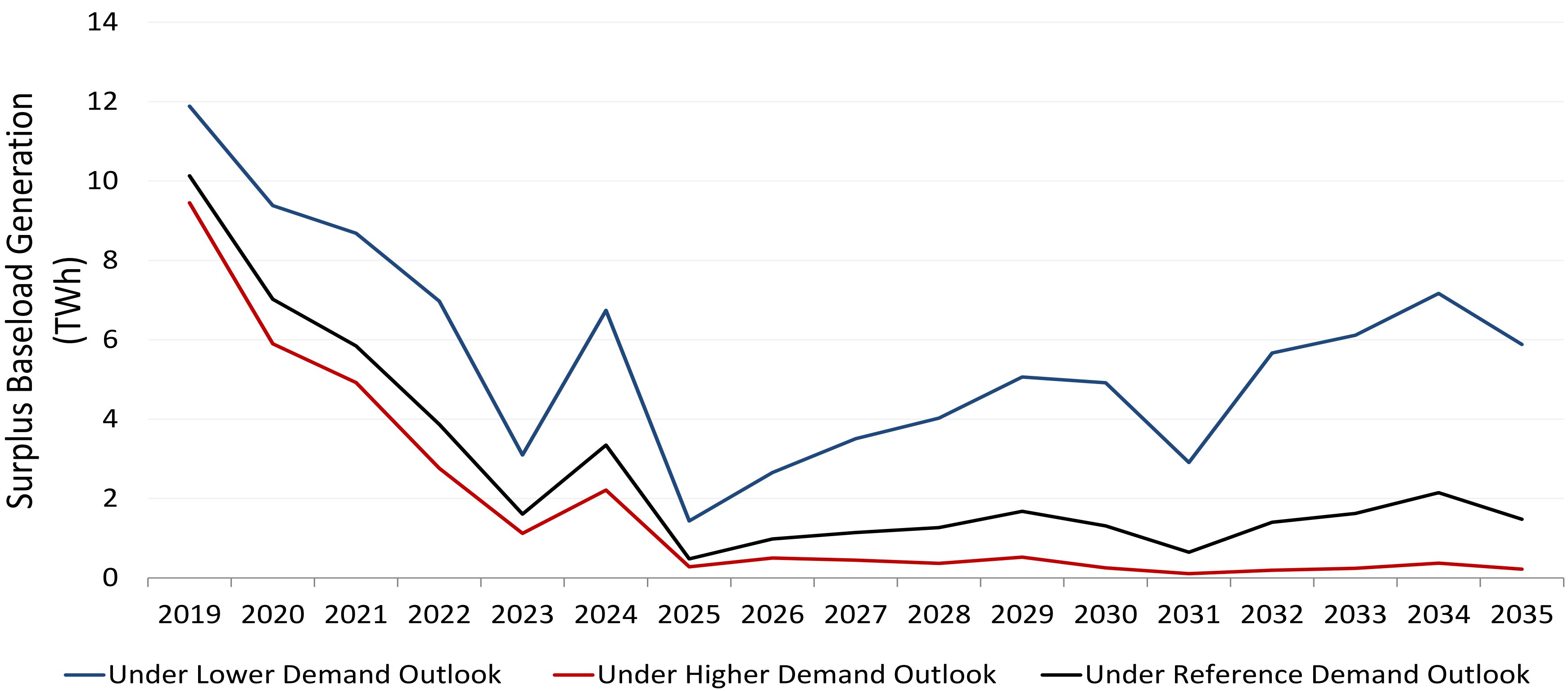
Energy adequacy outlook - key observations

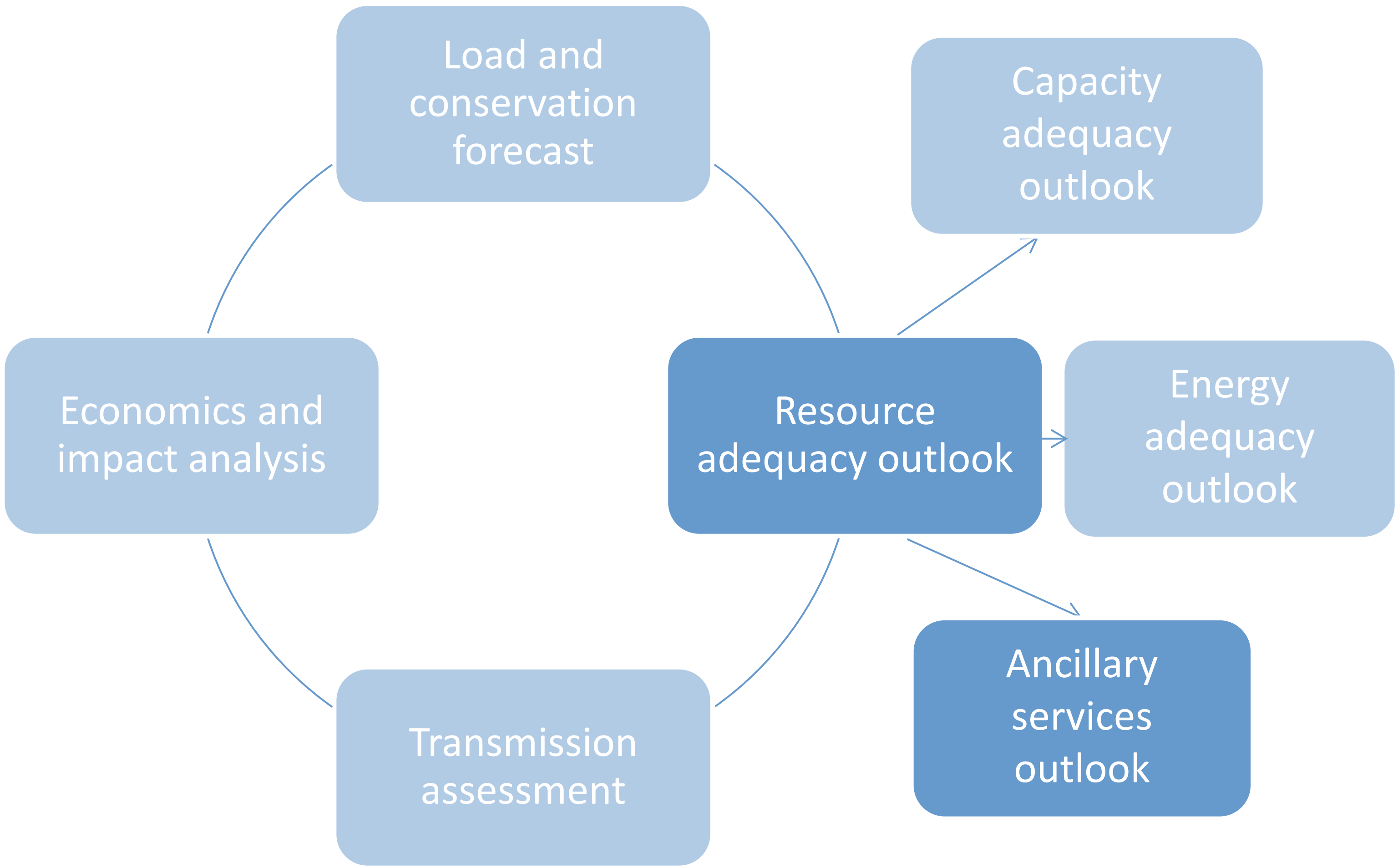
- Across the demand outlooks, it is seen that energy production from natural gas-fired generation changes the most, followed by energy production from hydroelectric generation. Nuclear and non-hydro renewable energy production remains unchanged across the demand outlooks.
- The natural gas-fired fleet increasingly plays the role of a swing resources and is expected to pick up the balance when output from other sources is lower or when demand rises.
- Absent continued availability of existing resources post contract expiration, Ontario is expected to remain energy adequate until the late 2020s. Energy production shortfalls would begin to emerge in the late 2020s.
- However, with continued availability of existing resources post-contract expiration, Ontario is expected to remain energy adequate throughout the planning outlook.
- Absent continued availability of existing gas-fired resources post contract expiration, production from gas-fired generators still under contract increases. Over time, production from these facilities would far exceed the utilization levels expected from those facilities (40-60% capacity factor for CCGT, 5-10% capacity factor for SCGT).

Surplus baseload generation (SBG)

- SBG occurs when the electricity production from baseload facilities such as nuclear, hydro, and wind is greater than Ontario's demand.
- SBG declines over time, driven by nuclear refurbishments and retirements.
- SBG could be higher under lower electricity demand scenarios. This would be managed through economic curtailments, nuclear manoeuvering or shutdown, exports, or by not reacquiring resources post contract expiration. Most of the surplus baseload conditions can be managed with existing market mechanisms, such as exports and curtailment of variable generation.



Ancillary Services Outlook



What are ancillary services?

- Ancillary services are those services required for the operation of the electricity system, necessary to maintain the reliability of the IESO-controlled grid.
- The transition to a more dynamic and transparent market, which includes the incremental capacity auction, requires forecasting of all reliability services (capacity, energy, and ancillary) to send transparent market signals for efficient investment decisions.
- Traditionally, in the near term, IESO has forecasted capacity and energy needs.
- The IESO currently procures a variety of ancillary services (summarized in the table below).

Ancillary Service	Ancillary Service
Operating Reserve	• Stand-by power or demand reduction that the IESO can call on with short notice to manage an unexpected mismatch between generation and consumption.
Regulation Service	• Acts to match generation to load and corrects variations in power system frequency. Operates on a time-scale of seconds. • Facilities vary output automatically in response to regulation signals.
Reactive Support and Voltage Control	• Allows the IESO to maintain acceptable local reactive power and voltage levels on the grid.
Black Start	• Helps in system restoration in the event of a system-wide blackout. • There may be a role to support future grid resiliency with the use of Black Start resources.

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Ancillary services outlook

- The IESO is evolving the market to create a more dynamic and transparent market that will send price signals for the different reliability products that are needed to reliability operate the grid today and tomorrow.

- In order to ensure market participants can make effective investments to respond to those needs, the IESO will be providing transparent forecast of all existing reliability services (capacity, energy, and ancillary services)

- Different resources provide different services to the electricity grid. Market products are needed for all different reliability services in order to make the electricity system operable.

Resource	Capacity	Energy	Operating Reserve	Load Following	Frequency Regulation	Capacity Factor	Winter Peak Contribution	Summer Peak Contribution
Conservation	Yes	Yes	No	No	No	Depends on Measure		
Demand Response	Yes	No	Yes	Yes	Limited	N/A	90%	90%
Solar PV	Limited	Yes	No	Limited	No	15%	5%	33%
Wind	Limited	Yes	No	Limited	No	30-40%	27%	11%
Bioenergy	Yes	Yes	Yes	Limited	No	40-80%	92%	92%
Storage	Yes	No	Yes	Yes	Yes	Depends on technology / application		
Waterpower	Yes	Yes	Yes	Yes	Yes	30-70%	74%	68%
Nuclear	Yes	Yes	No	Limited	No	70-95%	94%	93%
Natural Gas	Yes	Yes	Yes	Yes	Yes	up to 65%	86%	80%

- There is an increasing need today for some services such as flexibility/load following and regulation service.
  - Needs are being driven by the changing nature of the fleet including increasing amounts of variable generation and distributed energy resources as well as changes to the transmission and distribution system.
  - As the supply mix evolves, there may be a need to increase the types of services acquired and their quantities.

- The IESO is seeking to publish the longer-term requirements for ancillary services.

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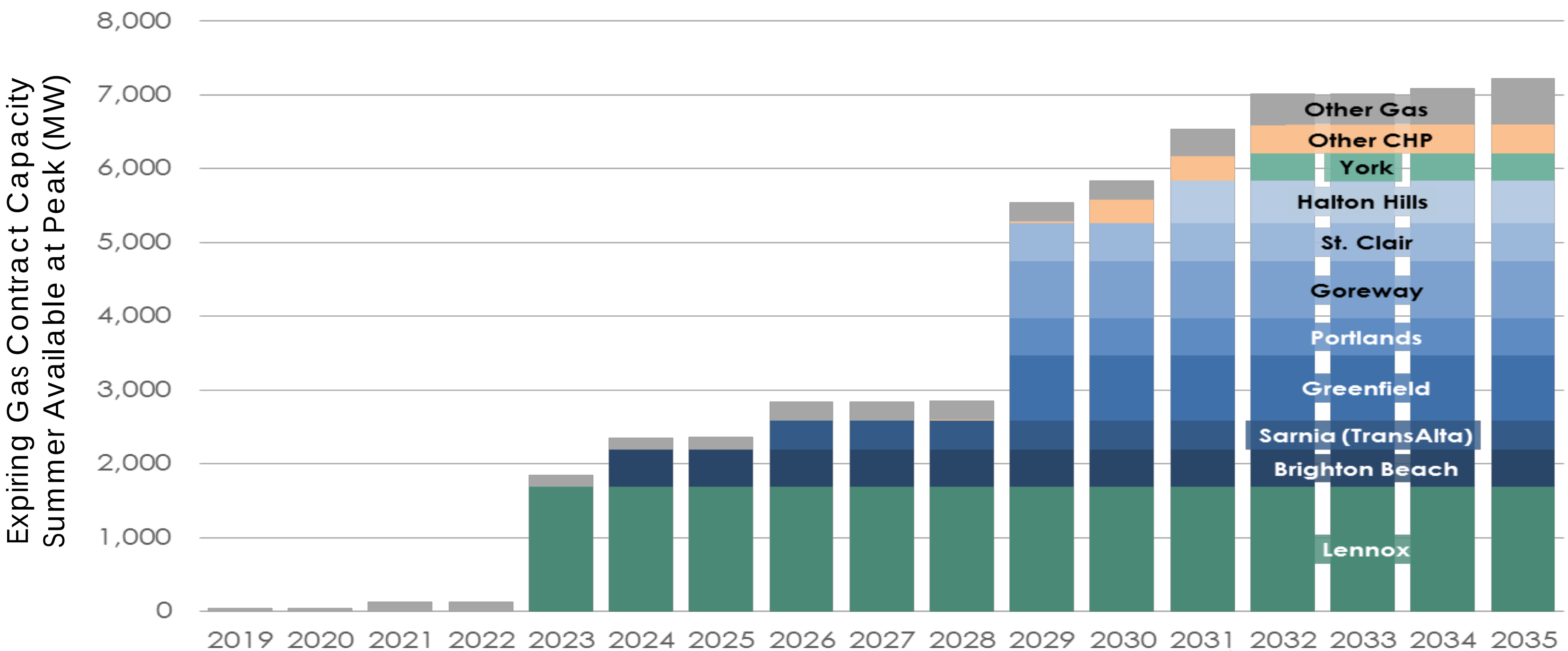
The gas generation as currently configured may not provide the operational flexibility required in the future

- Gas-fired generation capacity represents the majority of the available capacity at time of peak reaching end of contract term.
- Most of the gas-fired capacity expiring before 2035 is from seven combined cycle plants.
- Existing gas fleet is mostly combined cycle plants. These facilities are best suited to supply intermediate load and some ancillary services. Simple cycle gas plants are more suitable for providing peaking needs and many ancillary services.
- The existing market and contract terms do not provide incentives to the current gas generation fleet to provide the operational flexibility required today and in the future. Opportunities to enhance the market signals and incentives could result in investments to make fleet more flexible.



Facilities in "blue" are combined cycle plants.

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Key uncertainties impacting the resource adequacy outlook

- Various sector uncertainties will impact supply availability in the coming years.

Uncertainty	Details	Change in Capacity Need	Relative Impact
Refurbishment schedule risk (up to 1,500 MW)	An additional reserve is included in the capacity outlook to manage the risk of a delayed return to service after refurbishment. Uncertainty with respect to refurbishment schedules will remain into the 2020s.	Up or Down	*Large*
Generation retirements	Generation asset owners may revise when they plan to shutdown a plant. Will depend on condition of asset, cost of continued operation, and revenues generated. Some generation assets due to location and technical capabilities, play an important role in the system beyond providing capacity.	Up or Down	*Large*
DR Auction	DR is currently acquired through an annual auction. The December 2017 DR Auction cleared 561 MW for the 2018 summer and 712 MW for the 2018 winter commitment periods. Future auction parameters (e.g. target capacity) affect the availability of DR.	Up or Down	*Medium*
Existing assets post contract	There is limited information on the ongoing availability of generators with expired contracts. Some may participate in the Incremental Capacity Auction, while others may choose to decommission their facilities, mothball or begin operating as merchant capacity exporters.	Up or Down	*Small to Large*
Regulations	Such as with respect to environment. Can affect the extent to which a resource will continue to operate in the market.	Up	*Small to Large*

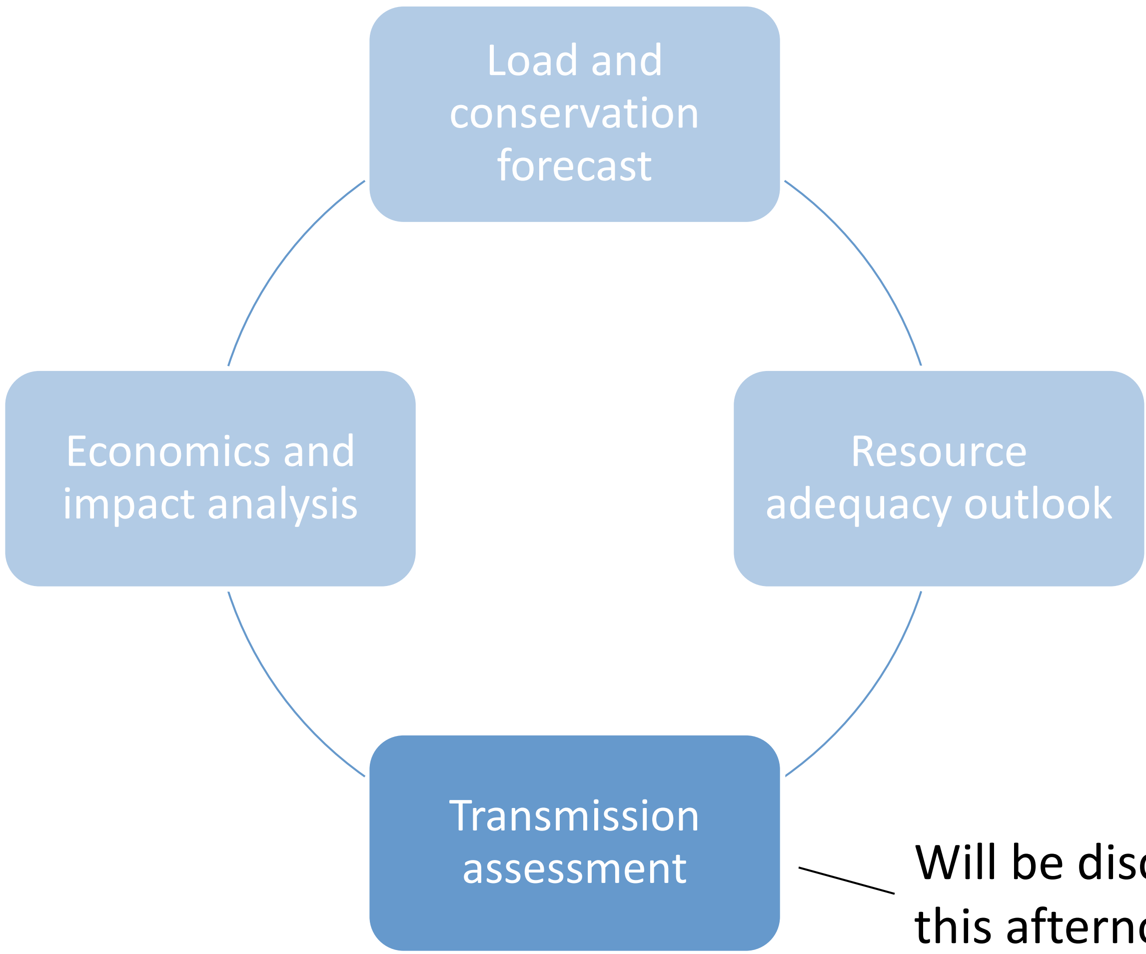
Questions

- What other key factors, uncertainties, scenarios, indicators, etc. should be considered in the resource adequacy assessment?

- How should we recognize and integrate risks related to the resource adequacy assessment?

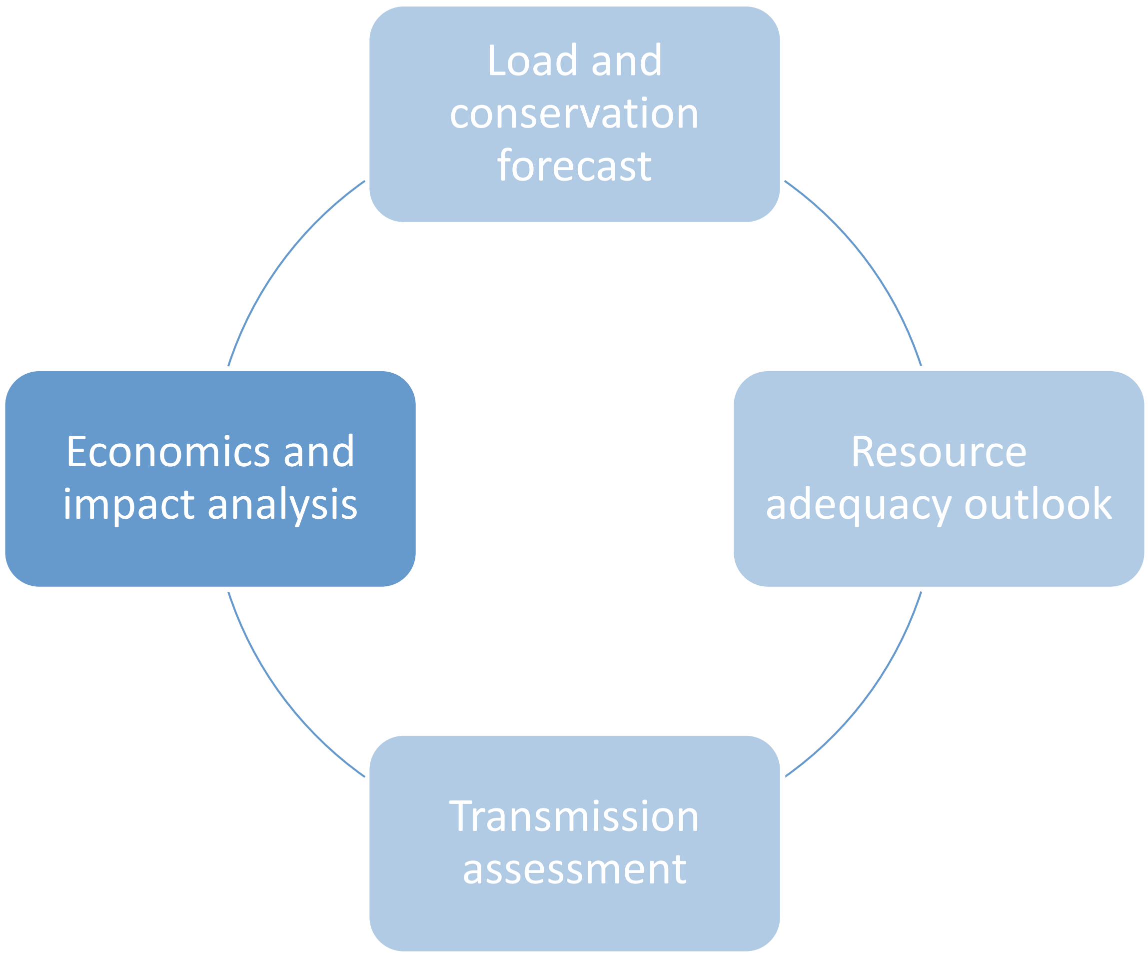
- What additional information should the IESO provide to the market?

Bulk system planning process – Transmission assessment

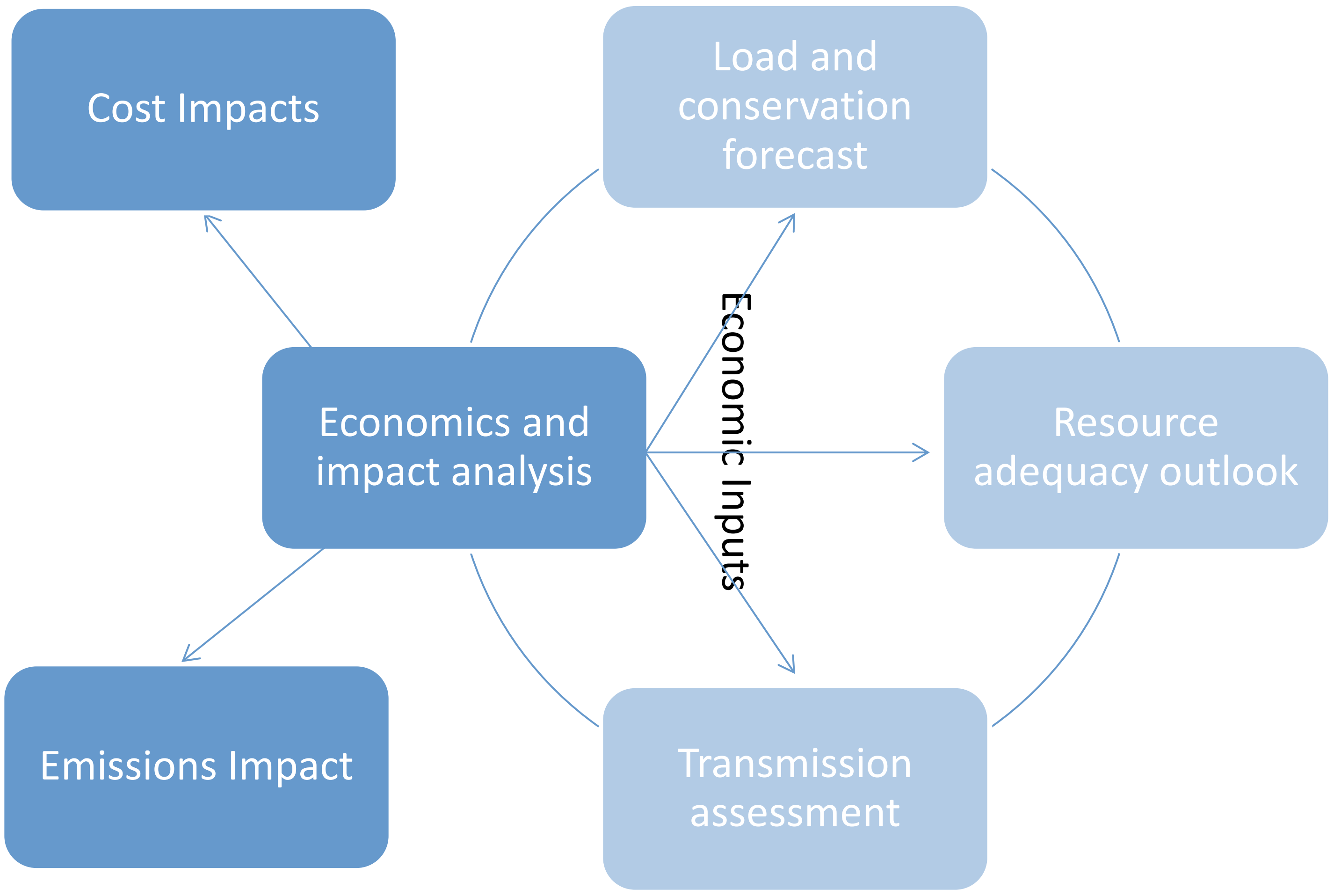


Will be discussed this afternoon

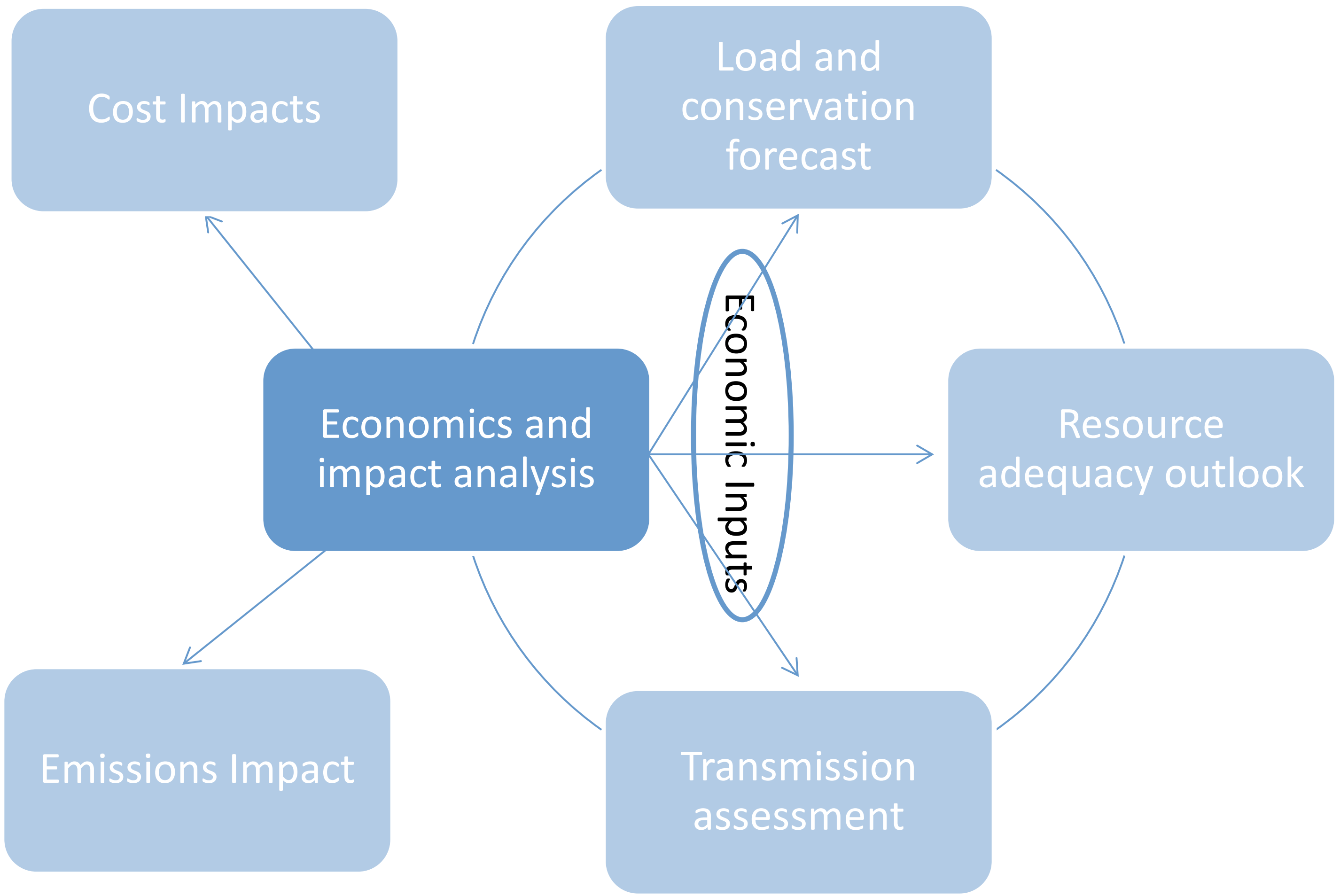
Bulk system planning process – Economics and impact analysis



What is economics and impact analysis?



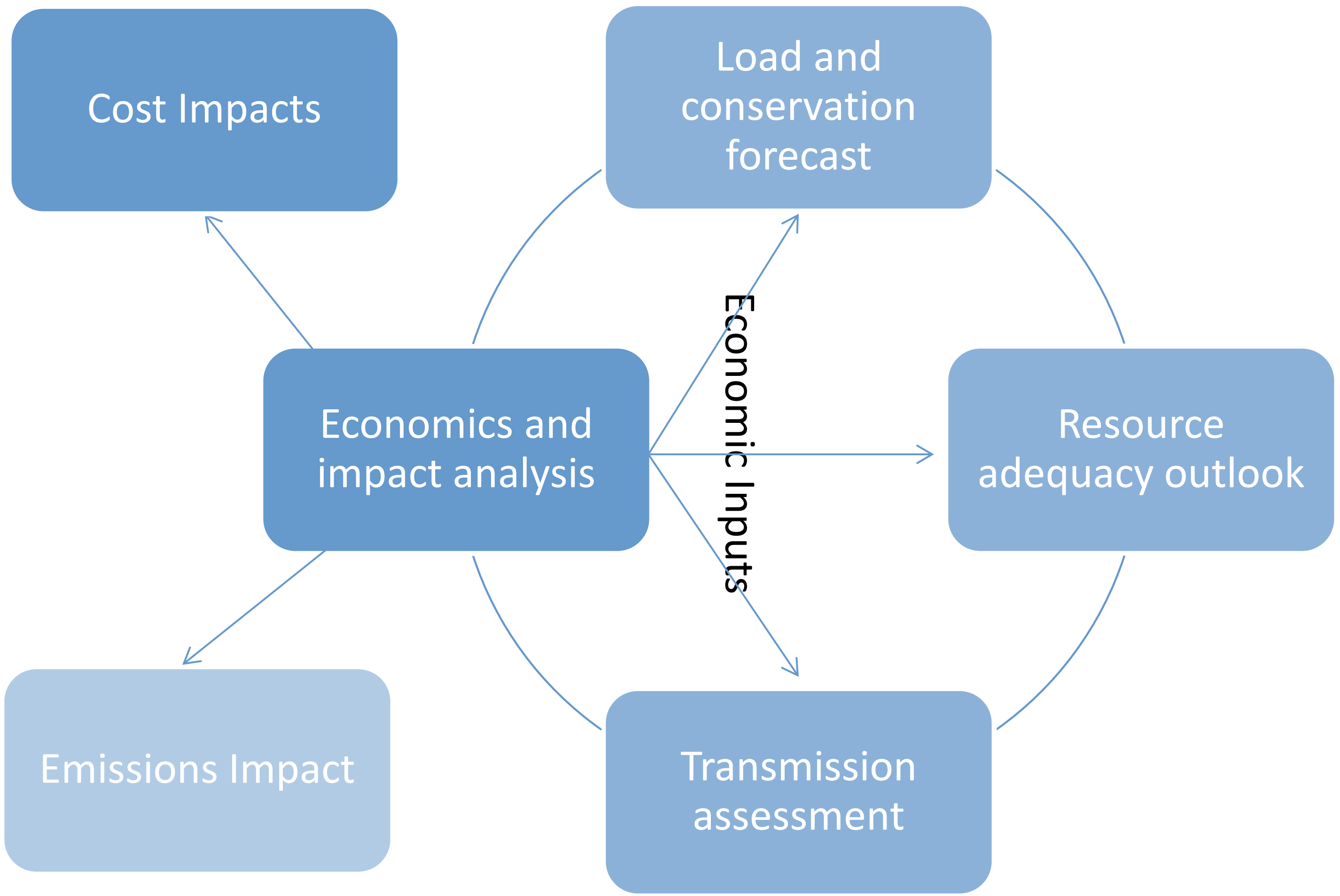
Economics and Impact Analysis – Economic Inputs



Economic inputs lay the foundation for planning

- Macroeconomic inputs: inflation, social discount rates for economic assessments (comparison of alternatives), exchange rates
- Understanding of electricity sector costs: capital and operating cost trends, contract costs and mechanisms, emerging technologies
- Inform resource dispatch in energy simulations
  - First principles approach taken including carbon and fuel price forecasting, gas delivery and management dynamics, contract and market mechanisms, emissions factors, interjurisdictional trade agreements
  - Includes Ontario and neighbouring jurisdictions
- Avoided cost of conservation
  - Informs conservation and demand forecasting by estimating the value of conservation based on energy or capacity products that would otherwise need to be purchased in absence of conservation.

Economics and Impact Analysis – Cost Impacts



Total cost of electricity components

i. Electricity Generation: All payments to generators for the production of electricity or provision of capacity, contract payments, regulated rates, and market revenue.

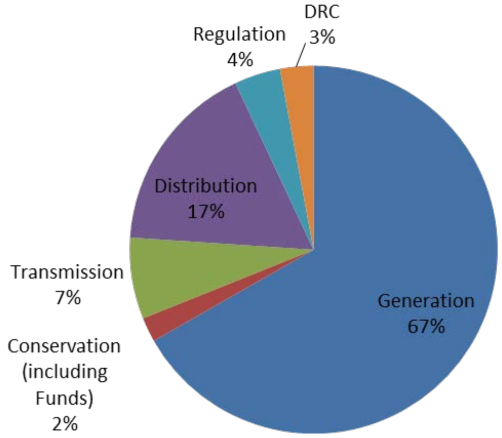
ii. Electricity Conservation: Program delivery and incentive costs recovered from electricity ratepayers, excluding equipment investments made by customers through conservation initiatives.

iii. Transmission Delivery System: Regulated revenue paid to transmitters for building, operating, and maintaining high-voltage transmission infrastructure.

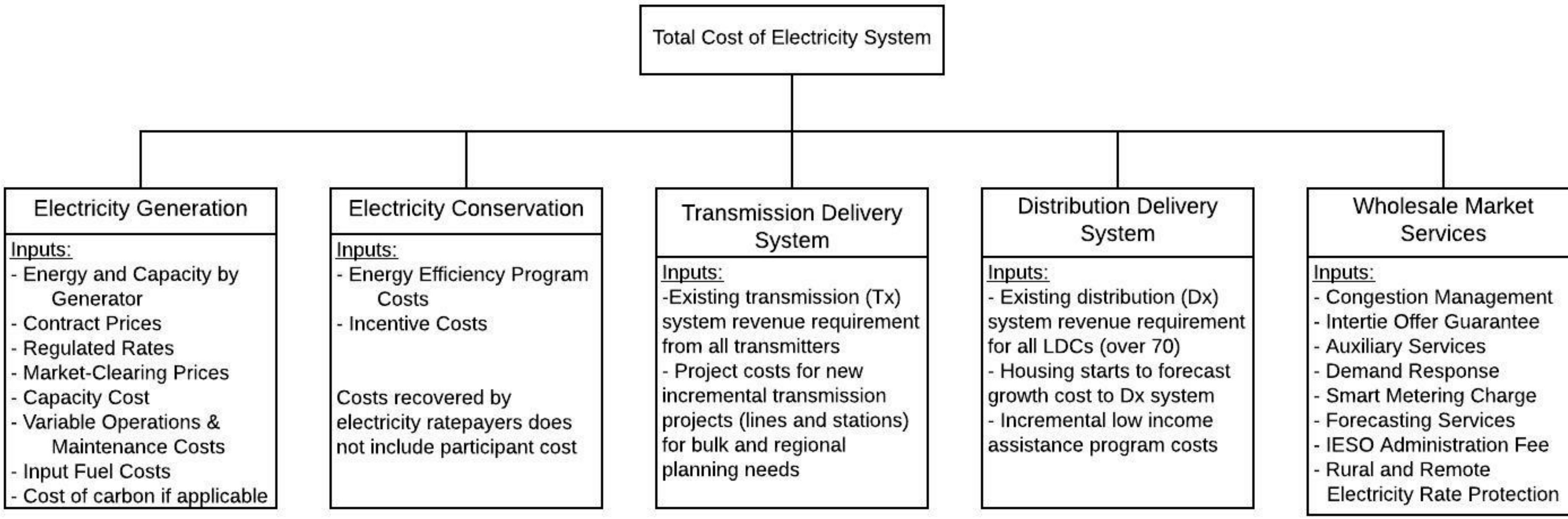
iv. Distribution Delivery System: Regulated revenue paid to local distribution companies for building, operating and maintaining low-voltage distribution systems.

v. Wholesale Market Services: These costs reflect the operation and administration cost for the electricity system, including payments for constraints and losses, provisions for reserves, black starts, IESO administration fee, rural and remote electricity rate protection, and demand response.

$20.6B in 2017



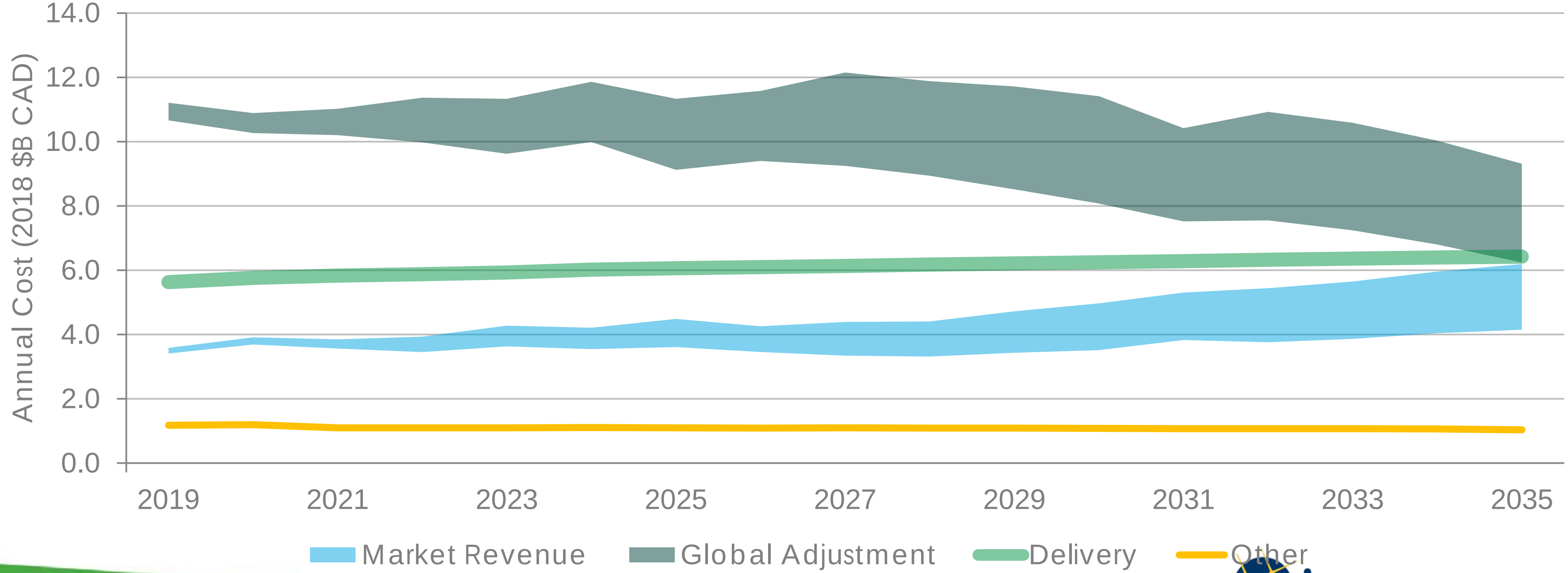
Total cost of electricity system key inputs



Note: Economic indexes apply to across all cost components (i.e. exchange rates, inflation rates, debt/equity ratios and etc.)

Estimate of electricity component costs

- Cost estimates are based on planning assumptions and are used to understand impacts relative to reference scenario.
- Decreased nuclear production and increased gas-fired generation lead to a modest increase in market revenues at a real cumulative annual growth rate of 2%
  - This assumes current energy market structure. Impact of Locational Marginal Pricing is not included.
- Increase in market revenues leads to a modest decrease in Global Adjustment (GA) at a real cumulative annual growth rate of -1.8%.
  - This assumes conservation funding framework and all new and existing capacity participating in the Incremental Capacity Auction (ICA) receives a notional estimate of the ICA clearing price. ICA Costs will likely be recovered through their own charge, but are included as part of GA in the chart below.
- Total electricity system costs and large volume rates expected to stabilize in real-terms.



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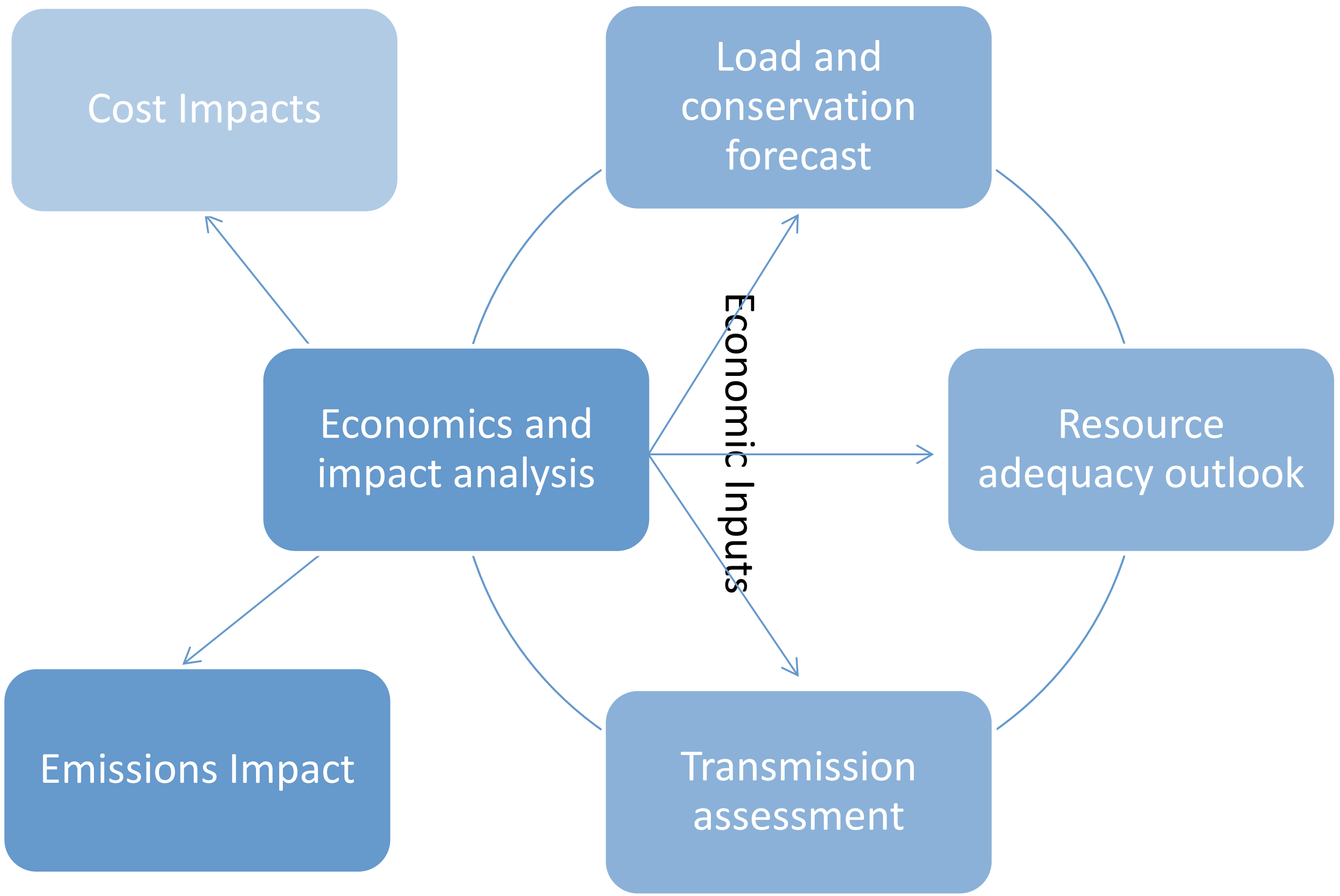
Economics and Impact Analysis – Emissions Impact



Cost of emissions are impacted by public policy

- Cap and Trade began on January 1, 2017 and officially ended in Ontario in July 2018.
  - Gas-fired generators did not have a direct compliance obligation, meaning generators experienced Cap and Trade as a pass-through cost from the natural gas utilities.
  - Under Cap and Trade, electricity was not considered emission-intensive and trade-exposed (EITE). Any EITE industry were provided free allowances worth the carbon price.

- Subject to the outcome of a challenge before the court, the federal carbon pricing backstop may be in place in Ontario on January 1, 2019. Unlike Cap and Trade, the backstop will mean:
  - Electricity generators have a direct compliance obligation, if above the emission threshold*
  - The electricity sector will be considered EITE. As such, an industry benchmark will be applied for the sector. The industry benchmark operates similar to providing free credits for gas-fired generators up to an emission rate equivalent to a typical combined cycle gas turbine.
  - If benchmark emission rate is exceeded, a carbon price will apply only above the benchmark.
  - If emissions are below the benchmark rate, generators will receive credits worth the carbon price.

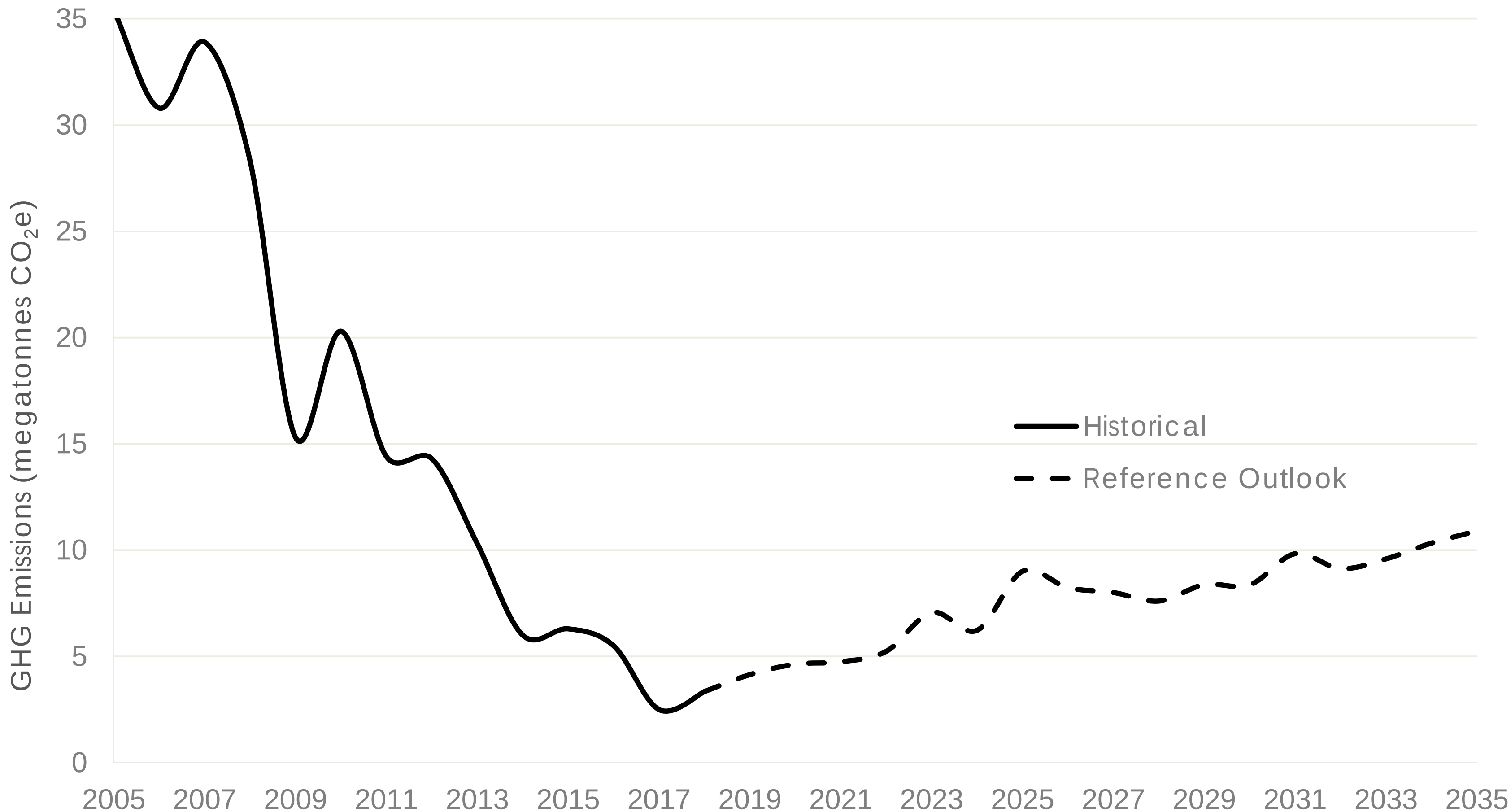
* Threshold initially set at 50,000 tonnes, with possibility to opt-in in 2020 if above 10,000 tonnes.

Emissions methodology and key inputs

- IESO typically reports annual GHG and air contaminant emissions for the planning outlook.
- GHG and air contaminant emissions are based on the production of electricity from emitting resources. In Ontario, the emitting resources in our supply mix include natural gas generators and the dual-fuel Lennox Generating Station.
- Inputs for the energy model related to emissions include carbon pricing in Ontario and in neighbouring jurisdictions, and any carbon pricing adjustments at the interties.
- Based on the current design, the anticipated impact of the federal carbon pricing backstop is likely to be minimal for the electricity sector, impacting less than 10% of the most expensive gas-fired generation. This will resemble a scenario without carbon pricing.
  - Moving forward, the energy model will consider a $0/tonne carbon price associated with the federal carbon pricing backstop.
  - As more clarity is provided regarding the final design of the backstop, the IESO will update the modelling to include the impact of the carbon pricing backstop for gas-fired generators.

Declining greenhouse gas (GHG) emissions

- Greenhouse gas emissions from the Ontario electricity sector have declined by more than 90% since 2005, reducing its contribution to total province-wide emissions from 17% to less than 4%
- Declining nuclear production will result in increased gas generation and greenhouse gas emissions; however, Ontario electricity sector emissions will remain well below historic levels over the next two decades



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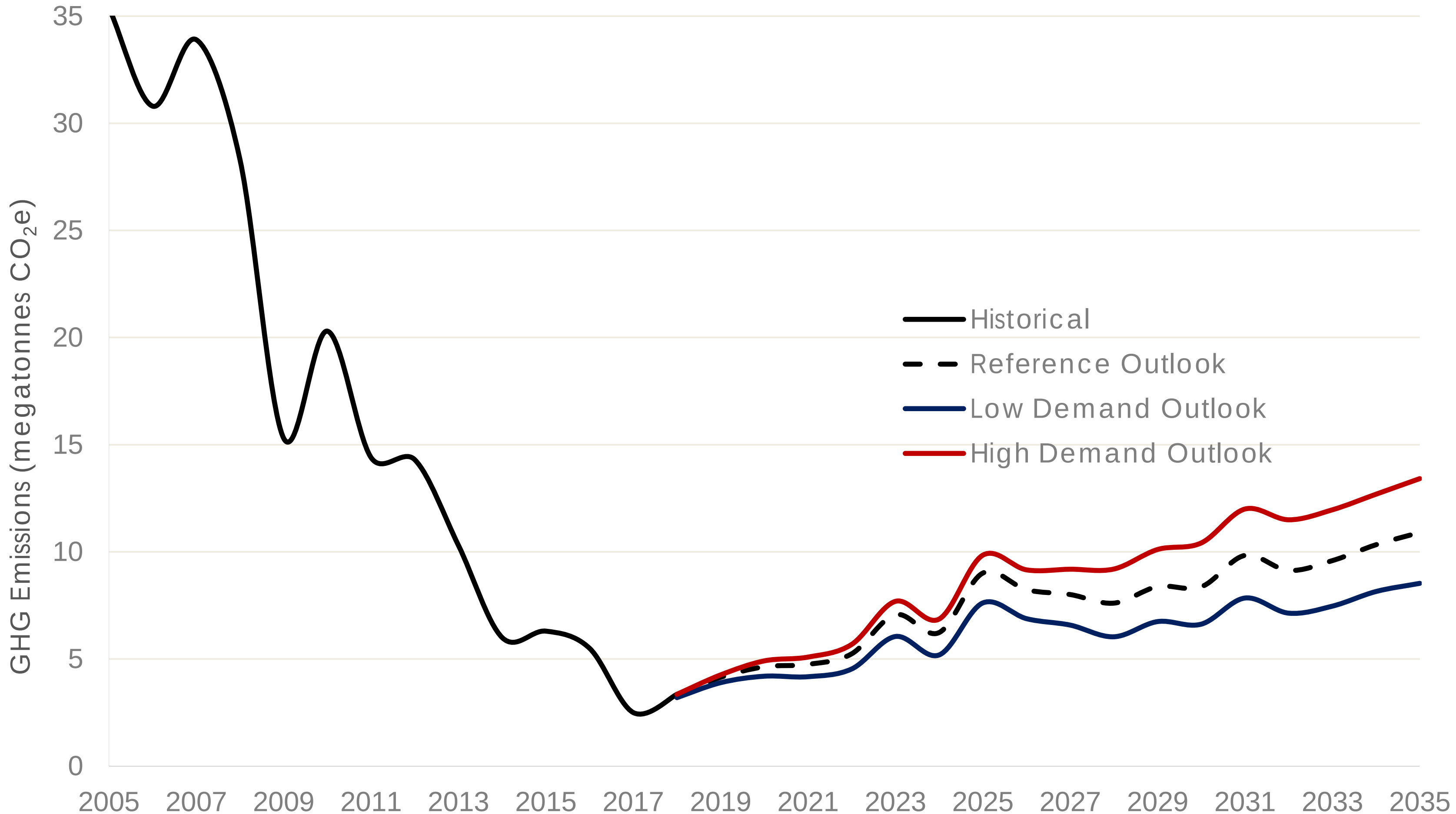
Impact of demand on greenhouse gas (GHG) emissions

- GHG emissions vary under different demand scenarios as natural gas-fired generation adjusts to meet demand. Emissions increase by an average of 14% for the higher demand scenario and decrease by an average of 18% for the lower demand scenario.



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Questions

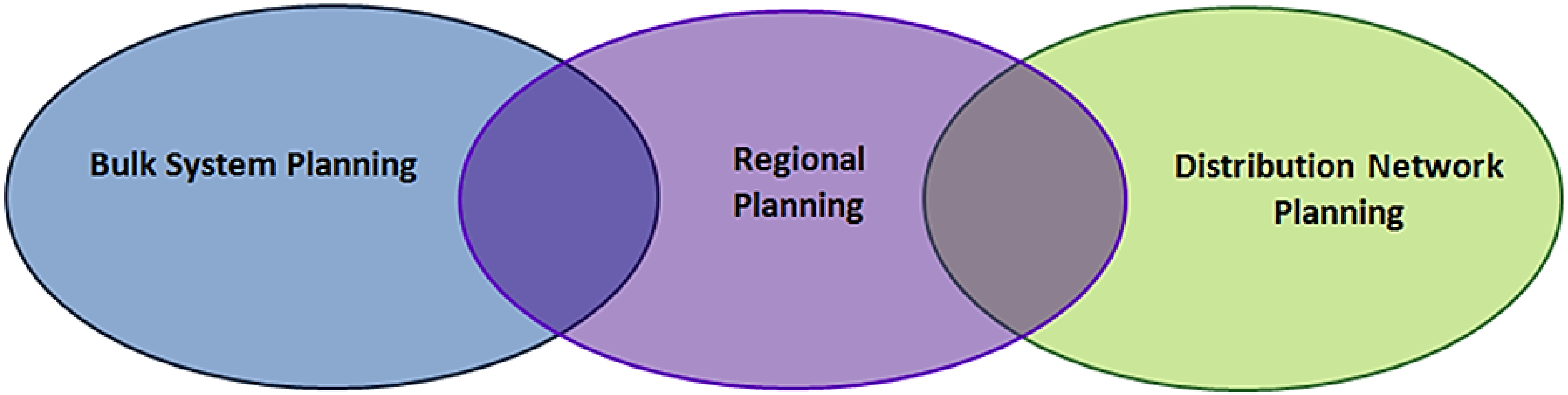
- What other key factors, uncertainties, scenarios, indicators, etc. should be considered in the economics and impact analysis?

- How should we recognize and integrate risks related to the economics and impact analysis?

- What additional information should the IESO provide to the market?

Evolution of Planning Processes and Products

System Planning Processes



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capability
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Addresses provincial electricity system needs and policy directions

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- & medium-term focused

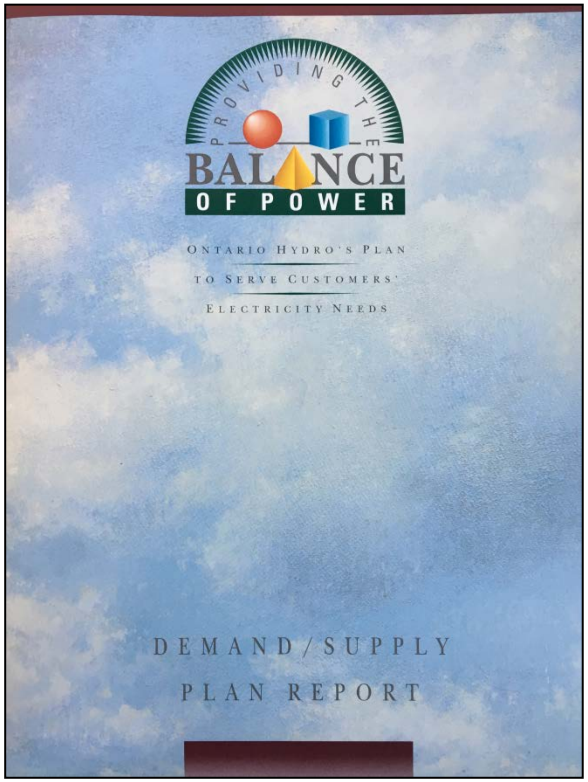
Integrates local electricity priorities with provincial policy directions & system needs

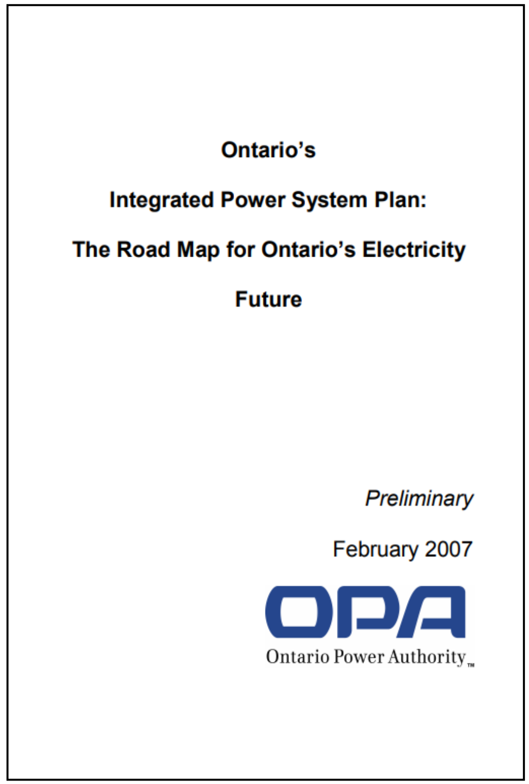
Distribution Network Planning

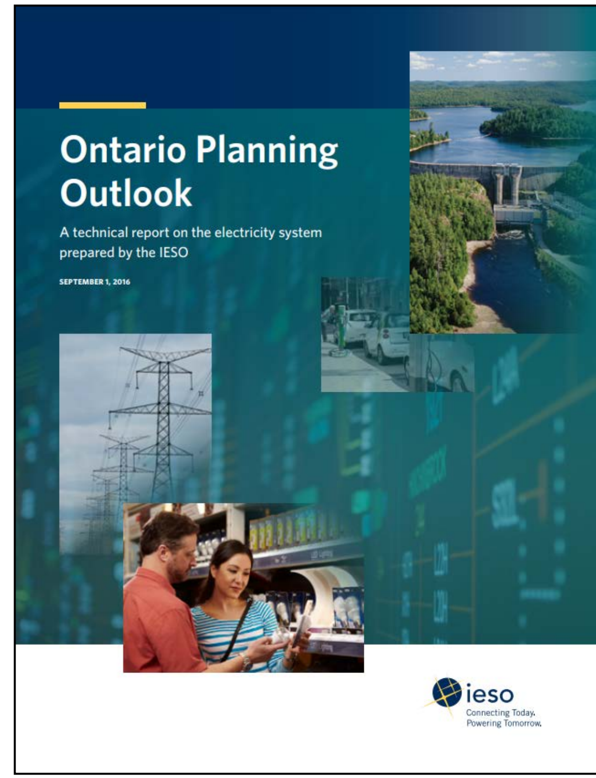
- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified Dx facilities)
- Distribution system reliability (capacity & security)
- Distribution connected generation & CDM resources
- LDC demand forecasts
- Near- & medium-term focused

Examines local electricity system needs and priorities at community level

System planning has been conducted in Ontario for many decades







- Planning processes and products are never static. System planning is continuously improving and adapting as the system changes and policy evolves (e.g. moving from a five-year cycle towards an annual cycle).

Key objectives of bulk planning and regional planning

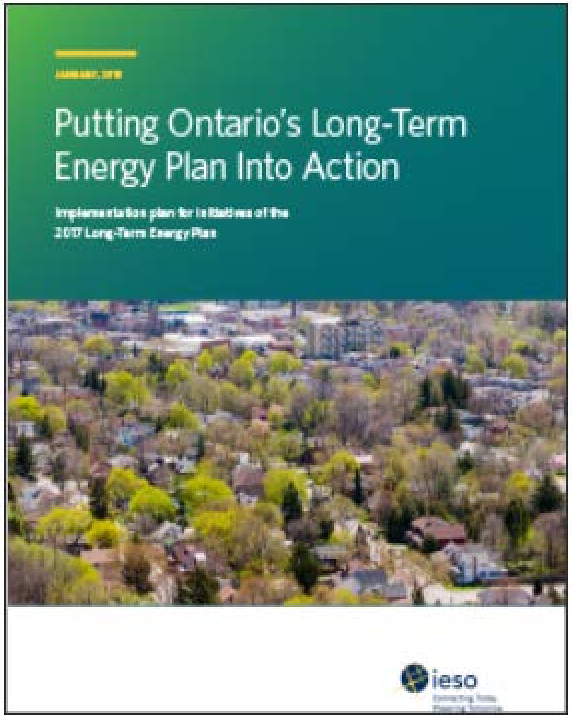
Ensure Reliability and Service Quality	Enable Economic Efficiency	Support Sector Policy and Decision Making
• Meet established criteria (NPCC, NERC, ORTAC) • Address operational issues • Seek solutions that simultaneously consider bulk system reliability needs, regional needs, and assets reaching end of life, as appropriate	• Seek opportunities to reduce losses, congestion, and other service costs • Facilitate intertie/trade requirements • Provide timely and relevant information to market participants to enhance their participation and decision making leading to greater market efficiency and competition	• Support policy implementation as affecting the power grid • Provide regulatory evidence, support, testimony (e.g., OPG nuclear, hydro)

Current planning framework – bulk system

- Energy Statute Law Amendment Act 2016 (Bill 135)
  - Government responsible for developing a long-term energy plan with the IESO providing technical reports as input, e.g., Ontario Planning Outlook
  - Minister of Energy can give the IESO and OEB directives regarding the implementation of the long-term energy plan, and requiring the parties to submit an implementation plan

Directive on bulk planning process improvement

- In January 2018, the IESO published an implementation plan, *Putting Ontario's Long-Term Energy Plan Into Action*, that outlines how the IESO will work with Ontario stakeholders to implement the initiatives in the Government's 2017 Long-Term Energy Plan
- One initiative focuses on the development of a formal integrated bulk planning process to ensure solutions are identified transparently as needs materialize
  - "Develop a formal integrated bulk system planning process that ensures solutions are identified transparently as needs materialize."



Current planning framework – regional

- The Ontario Energy Board endorsed the regional planning process in 2013
  - Transmitters, distributors and the IESO are required to carry out regional planning activities for the 21 electricity planning regions at least once every five years
- Changes to the Transmission System Code and Distribution System Code to reflect obligations for licenced transmitters and distributors to participate in the regional planning process
- Changes to IESO licence to reflect its obligations in the regional planning process

Directive on regional planning process improvement

- The IESO to review and report on the regional planning process and provide options and recommendations, considering as appropriate:
  - Identify barriers to non-wires solution implementation
  - Approaches for integrating the different levels of planning across the sector
  - Consideration of improved planning for replacement of transmission assets reaching end of life
  - Approaches for streamlining the regional planning process

Improving the planning processes

- Work is progressing on evolving and improving the bulk and regional planning processes
- Timeline and scope for completion of these initiatives are found in the IESO's LTEP Implementation Plan
- Process development to date includes information gathering, defining areas for improvements and integration with other evolving processes
- A major consideration is the integration of the planning processes with IESO's Market Renewal Project
- Plans are being developed to engage stakeholders impacted by the updated processes in the coming months

How planning products and information would evolve

- 18 Month Outlook
- 5 Year Reserve Margin Requirements
- Ontario Planning Outlook and Modules
- Long Term Energy Plan Modules

- Extended 18 Month Outlook
- Annual outlooks/planning reports and methodology documents to allow stakeholders to understand electricity needs

- Information to inform investors on present and future system needs to ensure investments are made effectively in response to what is needed to operate the grid reliably

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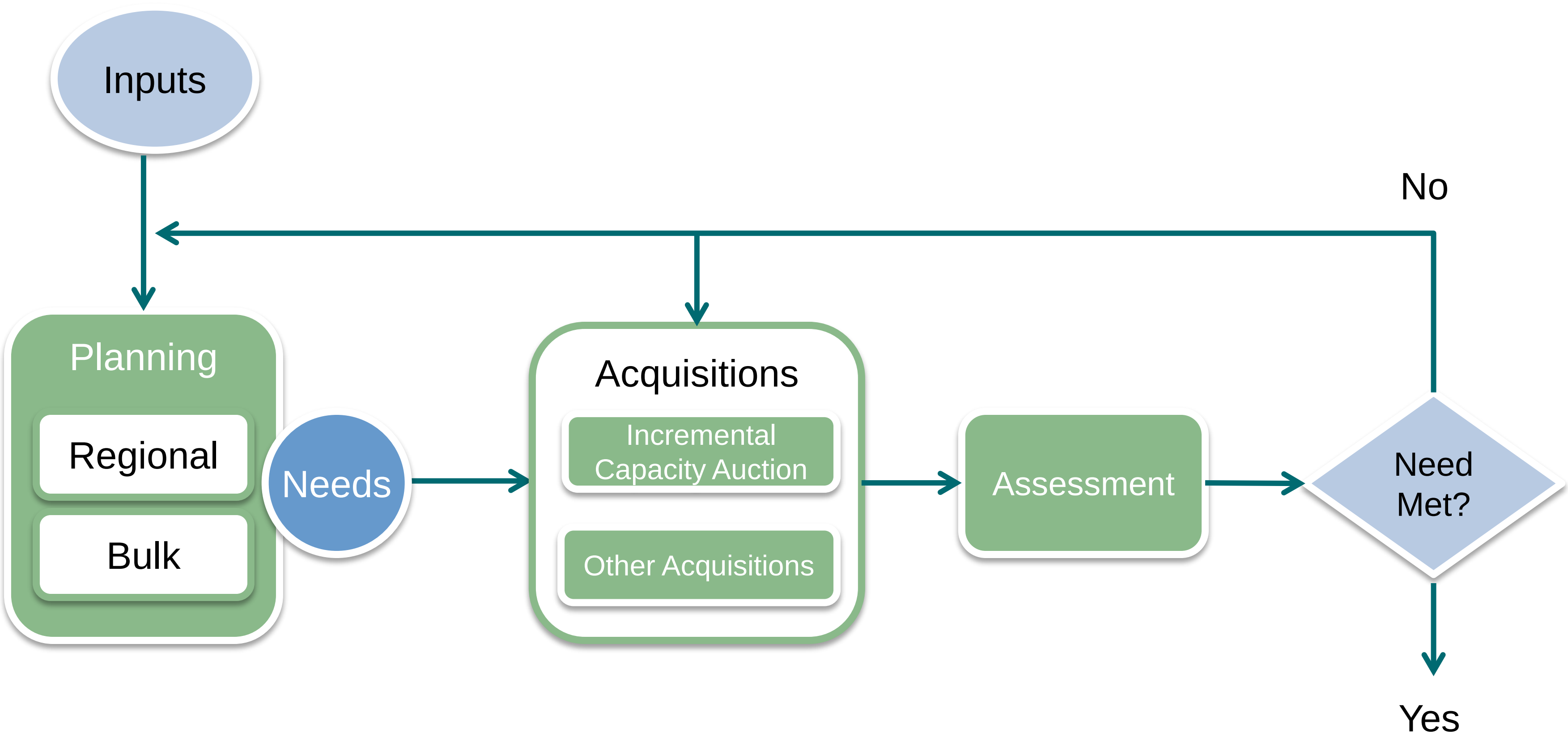
Purpose of public planning products

Planning process coordination with market



Extended 18-Month Outlook

- **Objective**: To assist market participants to plan their outages, recognizing that scheduling outages will become more challenging
  - Nuclear refurbishments and retirements of facilities impact the adequacy
  - Illustrate where opportunities exist for planned outages prior to the quarterly outage approval process (reduce chance of outages being placed at risk)

- **Action**: The IESO will be expanding the 18-Month Outlook to provide participants a longer view (up to 60 months)
  - A new section will be included to provide a "beyond 18-Month" view of resource adequacy, expected in December 2018
  - Will include a range of scenarios
  - A longer term view will aid all parties to coordinate outages in advance and have more certainty when developing an integrated operating plan

Annual outlooks/planning reports and methodology

- **Objective**: To provide timely and transparent information, on a regular basis, to guide investment decisions and market development

- **Actions**: The IESO will develop a regularly published outlook/planning report and a methodology document
  - Informed by the development of the Bulk Planning Process and the current and future electricity markets
  - To include various electricity scenarios and forecasts for capacity, energy, transmission and ancillary services needs
  - Information provided in the outlooks will be coordinated with and support the future market, including the Incremental Capacity Auction (ICA) objective
    - The objective of the future market, including the ICA, is to ensure reliability services can be acquired transparently and competitively through the market. This will ensure Ontario's resource adequacy needs are met cost effectively within the broader policy framework
    - For the ICA in particular, the planning related information will be communicated via a Pre-Auction Report, published ahead of each auction

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Scenario planning

- Future forecast updates will explore alternate scenarios in addition to the reference forecast so as to explore risks to the forecast and assess their implications

- Excerpt from "Scenario Planning Toolkit" by Waverley Management Consultants for the "Foresight Intelligent Infrastructure System (IIS) project"

  "Scenarios are a tool that organizations – and policy makers – can use to help them imagine and manage future more effectively. The scenario process highlights the principal drivers of change and associated uncertainties facing organizations today and explores how they might play out in the future. The result is a set of stories that offer alternative views of what the future might look like."

- Some common themes of scenarios including:
  – Recognize uncertainty
  – Explore drivers and the relationship between drivers
  – Are range-oriented
  – Set context for assessment of implications
  – Set context for action

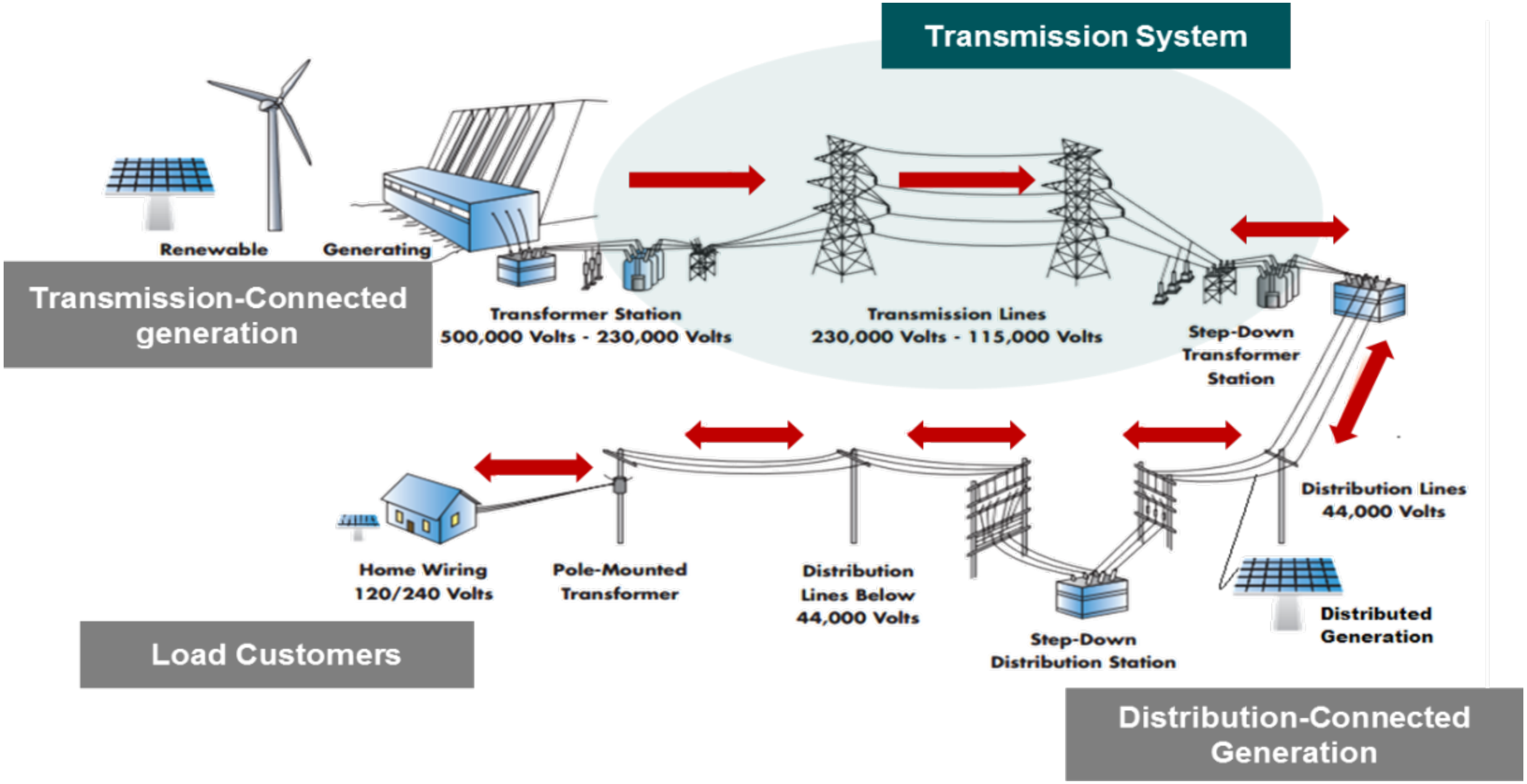
Questions

- What information would be of value for outage management planning?
- What information would be of value for guiding capacity, energy and ancillary services investments? For general planning information purposes?
- What additional information should the IESO provide to the market?

Introduction to Transmission Systems

Transmission System

- The transmission system is a complex network of high-voltage wires, transformer stations, switching and regulating devices that enables power to be delivered to where it is needed and to be shared between loads, customers and generators



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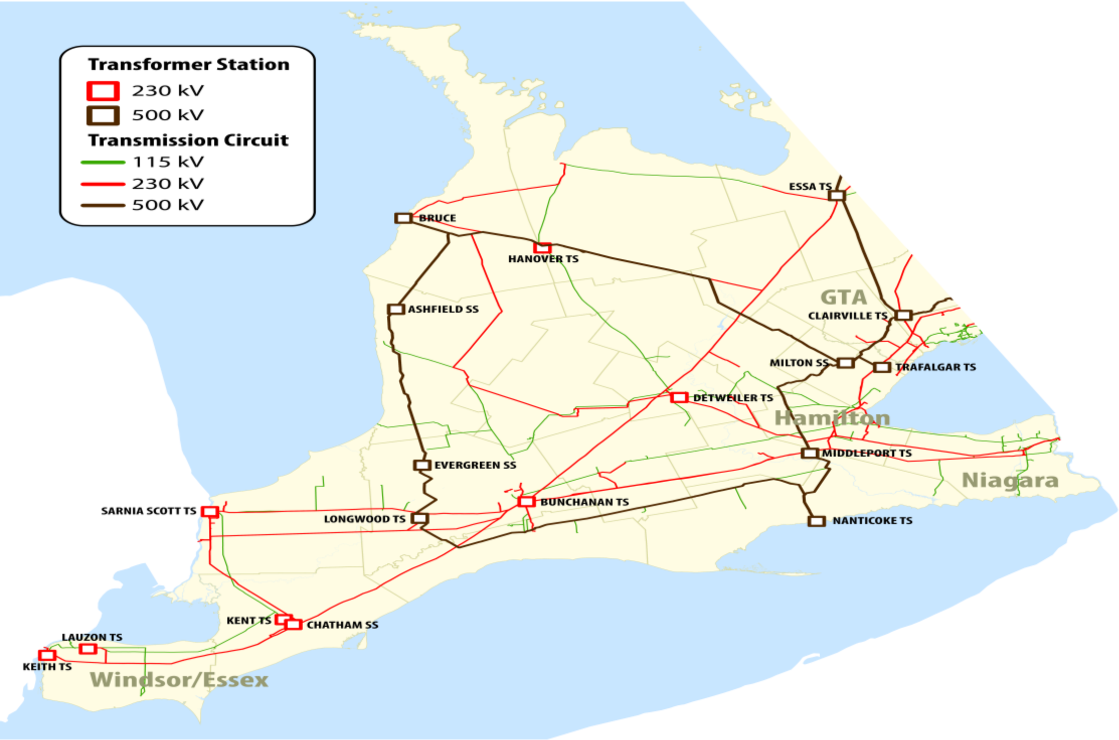
Network and radial connectivity



Transmission investment drivers

- Maintaining system reliability and security (e.g., responding to changes to the provincial demand and supply outlook)
- Maintaining supply reliability and service quality for customers (e.g., providing connections, enhancing capacity to support growth)
- Facilitating system efficiencies and flexibility (e.g., reducing congestion where merited)
- Supporting and enabling public policies that affect the power grid
- Replacing aging transmission assets

Typical transmission implementation process

Planning

Activities:
- Load forecasting
- Need identification
- Alternative analysis
- Systems studies
- Policy alignment

Project Development

Activities:
- Transmission Procurement
- Preliminary engineering
- Routing and siting
- Cost estimates
- Environmental Assessment
- Indigenous and Stakeholder Engagements/Consultations

Approval

Activities:
- Section 92 approval
- Other approvals as required

Construction

Activities:
- Construction of transmission line and station facilities
- Commission

Key Participants

Planning	Project Development	Approval	Construction
IESO	*IESO, Transmitter*	Transmitter, OEB	Transmitter

5-7 years

Aspects for consideration in the planning and implementation of major transmission facilities

- Long lead time, 5-7 years typical; needs and conditions may change over time
- Development work such as design and cost estimates, etc. may commence before commitment of facilities to reduce lead time
- Linear infrastructure – potential for significant land use and community impact
- Indigenous community interests – duty to consult and engage throughout the implementation process

Aspects for consideration in the planning and implementation of major transmission facilities (continued)

- Communities may be interested in alternative solutions
- Transmission projects will require obtaining various types of approvals, such as environmental, OEB, NEB etc.
- Cost responsibilities will need to be determined
- Facilities will need to be designed to area specific standards

Trends affecting transmission development

- Contracts for generators sited in transmission constrained areas will be expiring in the next decade
  - Given the long lead time required for transmission infrastructure, development work for these facilities may need to be initiated over the next couple of years, should it be required

- Some transmission facilities are approaching end of service life
  - Major transmission facilities are approaching end of life
  - A major re-build of some of these facilities is required (e.g., Phase shifters at St. Lawrence and Michigan, transmission corridor from Eastern Ontario to Toronto)

- Interjurisdictional capacity and energy trading
  - Transmission facilities may be required to facilitate interjurisdictional trading (e.g., firm/non-firm imports and exports) or parallel path flows (i.e., Lake Erie circulation), if required

Trends affecting transmission development (continued)

- System resiliency
  - Need to plan the transmission system to anticipate, withstand and recover from major outages and extreme events

- Increasing penetration of distributed resources
  - Need to consider these resources as alternatives to traditional transmission solutions and the impact of behind-the-meter activities as part of the planning process

- Variability and uncertainty
  - With the increased penetration of variable generation, growing demand forecast uncertainty, and fluctuating voltage conditions, the transmission system needs to be able to respond to these varying system operating conditions (e.g., greater reliance on control devices to regulate varying system voltage conditions)

Questions

- What other aspects are important for consideration in planning major transmission facilities?
- What additional drivers are there for transmission investment in Ontario?
- What additional information would be useful in understanding the transmission development process in Ontario?

Transmission Competitive Process

Part 1: Developing a New Competitive Process for Ontario

Outline

- Introduction to Competitive Transmission Procurement
- Why Develop a Competitive Transmission Procurement Process
- Engagement Plan and Timelines
- <Break>
- Presentations / Panel Discussion

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Introduction to competitive transmission procurement (context)

- Competitive transmission provides opportunity for parties to compete to do one or more of:
  - Develop, design, finance, build, own, operate, and/or maintain transmission facilities

- Competitive transmission procurement is not new to the industry or Ontario
  - Competitive transmission system development is being implemented in many jurisdictions
  - Currently being used in Ontario for connection facilities (as opposed to network facilities), including transmission stations and lines to connect new customers

Current process – two main approaches

1. Transmitter initiated (non-competitive)

- Application to the OEB either a rate case or a leave to construct
- With/without IESO/government support
- More than one transmitter can apply for the same project
- Projects usually fall to the existing facility owner

2. Designation process

- Competitive process run by the OEB
- Multiple transmitters participated
- Only used once for the E-W tie project

Authority for developing a competitive transmission procurement process

- Under a government-approved implementation plan or a directive, the IESO has the legislative authority to enter into contracts for the procurement transmission systems, or parts thereof
  - Reflected in amendments to the *Electricity Act, 1998*

- Transmission competitions are generally administered by independent system operators across North America

Scope of competitive transmission procurement process

- Develop a flexible, scalable process to guide future competitive transmission procurement or transmitter selection
  - The design and principles of the process to reflect findings from community / stakeholder engagement
- Opportunities for Indigenous community participation
- Identify pilot project(s), if any are suitable

Engagement Plan

Phase	Description	Timing
Phase 1	Launch and Early Design Work	September 2018
Phase 2	Broad Engagement	Until Q1 2019
Phase 3	Draft Process Document(s)	Q1 (March) 2019
Phase 4	Final Process Document(s)	Q2 2019

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How to Participate

- Link to Webpage:

http://www.ieso.ca/en/sector-participants/engagement-initiatives/engagements/development-of-an-ieso-competitive-transmission-procurement-process

- Link to Draft Engagement Plan:

http://www.ieso.ca/-/media/files/ieso/document-library/engage/tpp/tpp-engagement-plan.pdf?la=en

- Contact email: engagement@ieso.ca

Transmission Competitive Process

Part 2: Experiences in developing and participating in competitive transmission procurement processes

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Introduction of Speakers

- Topic: *Experiences in developing competitive processes and participating in transmission competitions*
  - Jason Connell, PJM Interconnection
  - John Dalton, Power Advisory, LLC (moderator)
  - Ryan Ferguson, AESO
  - Aubrey Johnson, MISO
  - Jennifer Tidmarsh, NextEra Energy Transmission, Canada

Engagement Opportunities and Next Steps

Upcoming engagement opportunities

Timing	Engagement Activity
October 2018	First Nations Energy Symposium
October/November 2018	Regional Energy Forums
October 2018	Market Renewal - Incremental Capacity Auction Stakeholder Engagement Meeting
Q3-2018 to Q2-2019	Competitive Transmission Procurement Process – Community and Stakeholder Engagement
Q4-2018	Bulk Planning Process initiative - Phase 1 Stakeholder Engagement
Q2-2019	Bulk Planning Process initiative - Phase 2 Stakeholder Engagement

Feedback / wrap up

- All participants are invited to provide feedback on the overall effectiveness of the conference.

- In addition, we encourage all stakeholders to provide feedback and comments on the content/questions posed during today's presentation through our website by **October 12, 2018**. http://www.ieso.ca/en/sector-participants/planning-and-forecasting/technical-planning-conference

- Feedback will be summarized and posted on the IESO website by Q4 2018. Feedback received will help inform IESO's planning processes and further discussions at future stakeholder engagement meetings.

- Email us: engagement@ieso.ca

TAB B

EXHIBIT "B"

referred to in the Affidavit of

DAVID SHORT

Sworn October 25, 2019

Commissioner for Taking Affidavits

Capacity Update

Stakeholder Advisory Committee

August 14, 2019

SAC Input

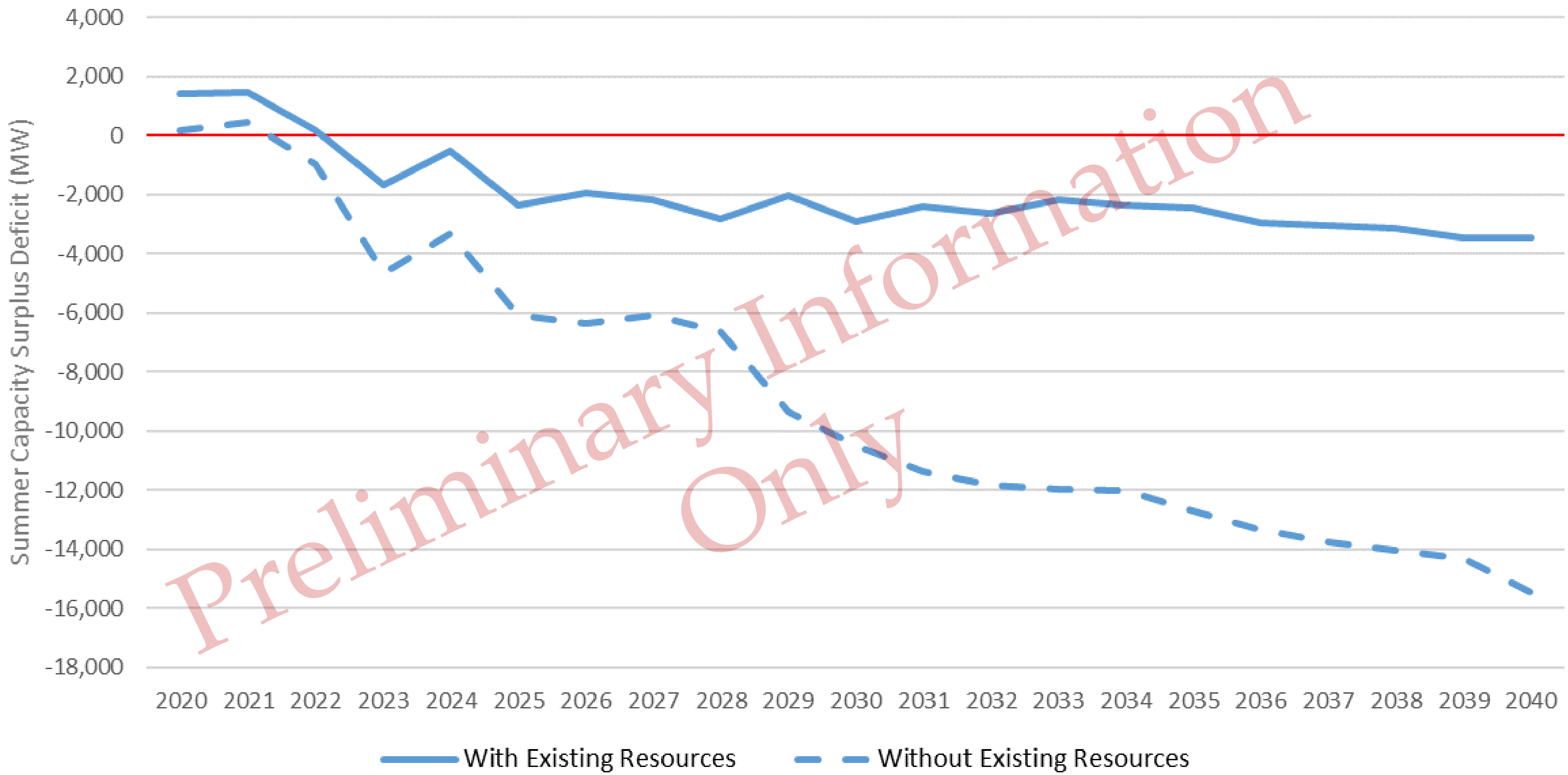
SAC's input is requested in the following areas:

- Preliminary resource adequacy outlooks
- Acquiring capacity
- Proposed engagement approach

Overview of preliminary resource adequacy

- The IESO’s preliminary assessment for the 2019 planning outlook confirms that over the next decade Ontario has a limited need for new-build capacity if existing Ontario resources are reacquired when their contracts expire
- Ontario is energy adequate and IESO does not forecast a need for new baseload resources (e.g. nuclear and large hydroelectric) over the next 10 years
- The Annual Planning Outlook will be released in Q4 2019

Preliminary resource adequacy outlook: summer



Notes:

- Existing resources includes continued availability of Demand Response
- Continued level of energy efficiency factored into the demand forecast

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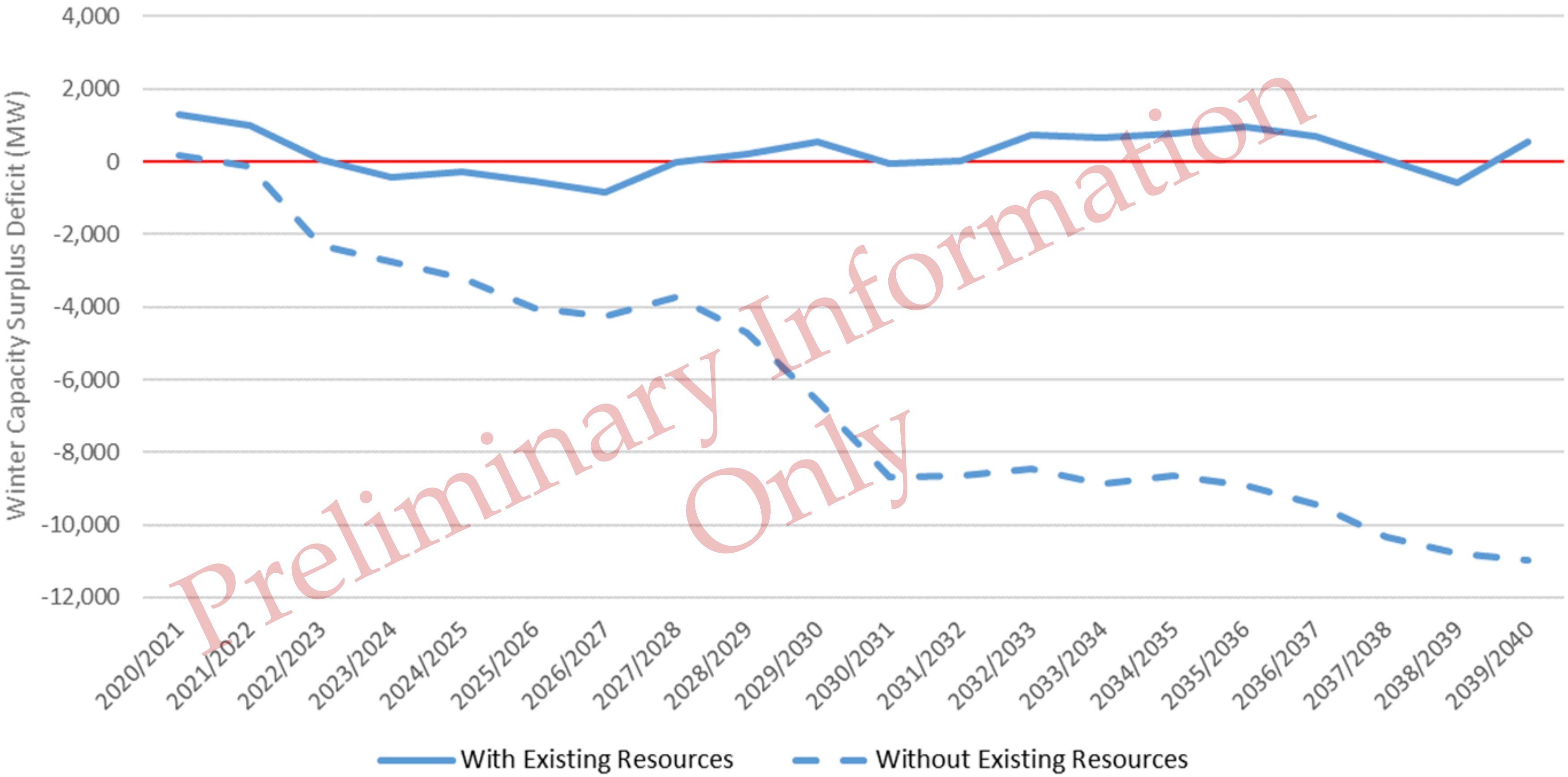
Preliminary resource adequacy outlook: winter



Notes:

- Existing resources includes continued availability of Demand Response
- Continued level of energy efficiency factored into the demand forecast

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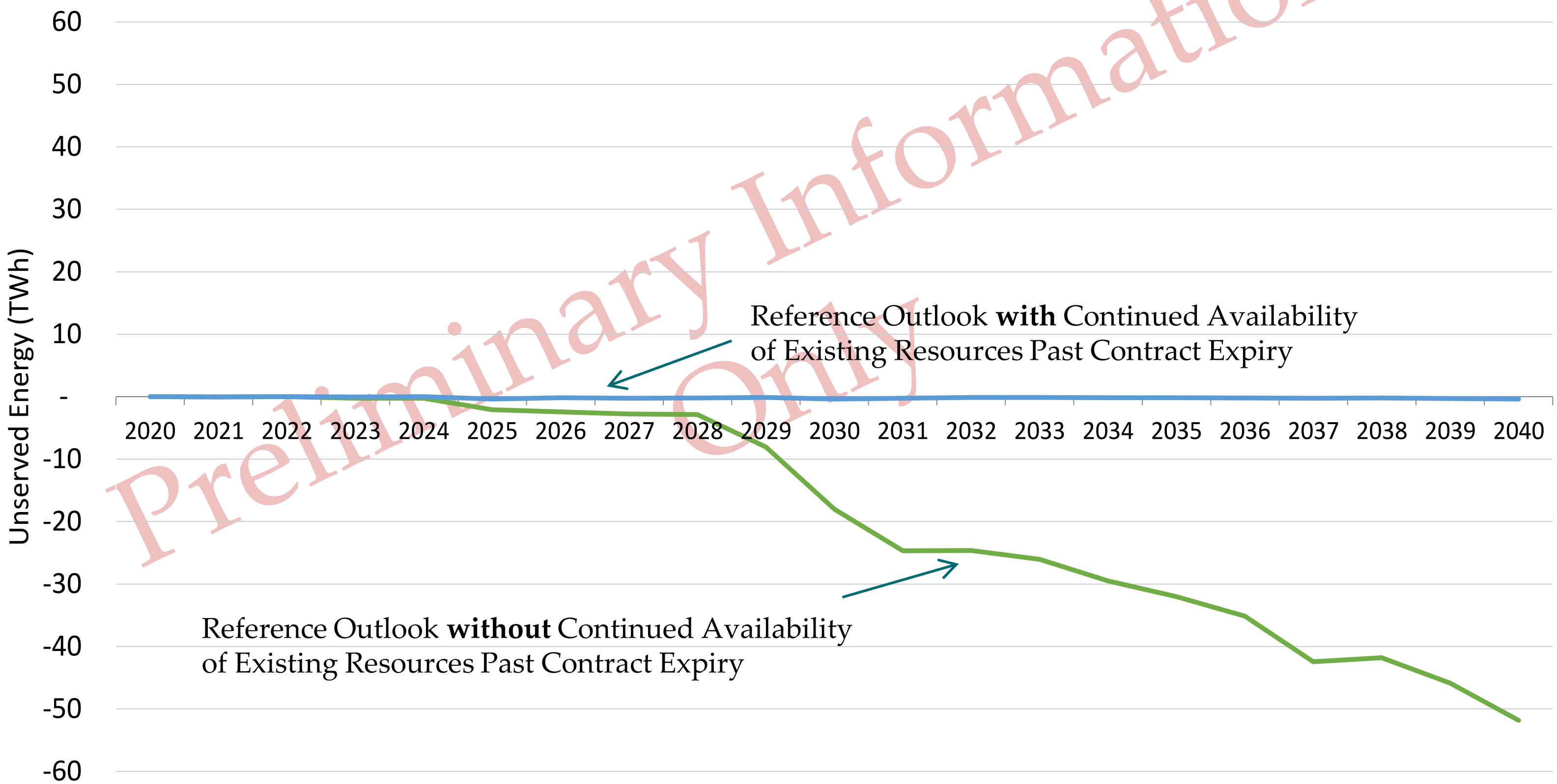
Energy Adequacy Outlook

- Ontario is able to meet needs in most hours over the outlook if existing resources continue to be available post contract expiration, this reflects the gas fleet's ability to produce more energy as nuclear retirements and refurbishments occur.
- If existing resources do not continue to participate, significant energy needs emerge around 2028 as the large Clean Energy Supply Contracts reach the end of term



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Options available to meet capacity requirements

- Near-term requirements can be met by existing and available resources
- Expected to participate in the Capacity Auction:
  - Demand Response
  - Existing generation that is, or will be, off-contract
  - Imports
  - Existing facility uprates
- Energy Efficiency programs are expected to continue to contribute after 2020 and IESO will explore more competitive acquisition mechanisms such as participation in markets
- 500 MW Hydro Quebec firm import available until 2030 for 1 summer commitment period under the terms of the HQ energy deal
- Opportunities may exist to optimize and shift nuclear availability through the refurbishment period

Recap of July 17 MRP Update on ICA

- IESO is stopping work on the High Level Design (HLD) for the Incremental Capacity Auction (ICA)
- As the system operator, IESO remains committed to competitive mechanisms for acquiring capacity
  - Auctions will provide an open, transparent, competitive and reliable way to meet capacity needs
- IESO will continue to implement the Transitional Capacity Auction (TCA) with a first auction this December
- IESO will evolve the TCA over the next few years including a review of:
  - How ICA feedback should be reflected in plans going forward, and
  - Which features from the original HLD are needed to support the next phases in an enduring capacity auction mechanism in Ontario

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What We Heard at the MRP Update Meeting

Topic	Overview of Feedback Received	Meeting Response
Resource Adequacy	• How does the IESO plan to address longer-term resource adequacy needs? • Market accepts that IESO is going to continue with short-term auctions but there needs to be a broader consultation on alternative procurement mechanisms	• The IESO remains committed to engaging the sector on resource adequacy and broader conversations on this topic. • The IESO is also committed to competitive mechanisms, starting with the TCA.
IESO Revenue Requirement	• What is the impact on the IESO's 2019 revenue requirement given that work is stopping on ICA HLD development? • How does this change impact the IESO's 2020 revenue requirement?	• This change will result in reduced capital requirements in 2019 and in 2020. There are 5 months left in 2019 and there is still work to be done on the capacity auction process. IESO's 2020-2022 Business Plan will reflect updated 2020 requirements.

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What We Heard at the MRP Update Meeting

Topic	Overview of Feedback Received	Response / Next Steps
Transitional Capacity Auction	• Stakeholders will be paying closer attention to the TCA. • Will there be a refreshed stakeholder engagement? • How will the scope and timeline for the TCA evolve? • What is the impact on annual target capacity values? • There is a need for a business case to justify spending on the TCA.	• The IESO will evolve the TCA fully informed on what stakeholders have said about the ICA and will continue to engage with the sector. • The IESO will stakeholder updates to the target capacity value. • The costs of the TCA are much smaller and may not require the same level of scrutiny as for the ICA.
Impact on the Business Case	• Why is the TCA outside of the business case? • How does removing the ICA affect the benefits of MRP? • Will Market Participant costs be included?	• The TCA is not part of the MRP and is similar to other projects that get incorporated into the capital budget. • The IESO Board has approved the TCA Project Phase 1 and Phase 2 proposed spend. • The overall MRP benefits will be smaller with ICA removed though the details are still to be determined. • Market Participant costs due to MRP will be discussed qualitatively.

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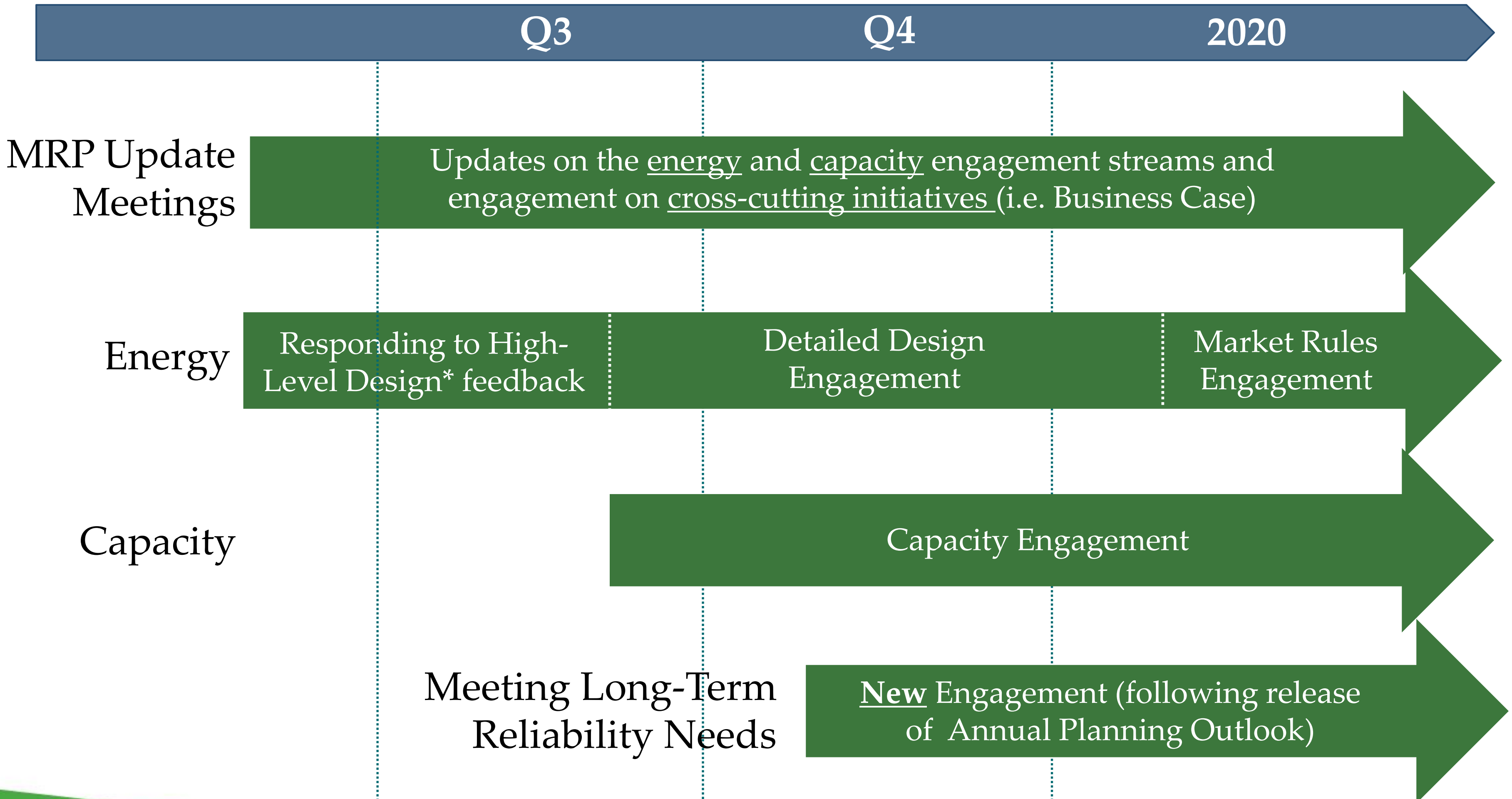
Future Engagement Approach

- **Capacity Engagement:** Focused on the development of a future capacity auction
  - To engage stakeholders who provided comments on the ICA HLD to carry-over important design details to a future capacity auction
  - To continue with Phase II and future phases of capacity auctions
- **Meeting Long-Term Reliability Needs Engagement:** Focused on options for meeting longer term resource adequacy needs
  - To develop a quantitative and qualitative assessment of various resource acquisition mechanisms for Ontario's forecasted future needs and applicability of their uses
  - To develop a common understanding with stakeholders to ensure we find ways to satisfy Ontario resource adequacy as effectively as possible in the future

Engagement Approach



IESO Capacity Auctions

	Aug 2019		Oct 2019	Dec 2019	Oct 2020
TCA Phase I *Evolve the demand response auction (DRA) into a broader and more competitive capacity acquisition mechanism*	**Technical Panel Aug. 13** Vote to recommend - Phase I Draft Market Rules	**Board Meeting Aug. 28** Vote to approve – Phase I Draft Market Rules	**Phase I Rules Effective** To enable registration activities prior to the auction	**2019 Transitional Capacity Auction** First TCA runs on Dec. 4, 2019	
Phase II		**Phase II Engagement** Expand participation to imports, uprates, and storage (TBD). Includes Phase IIa (June 2020 auction) and Phase IIb (December 2020 auction)			

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SAC Input

SAC's input is requested in the following areas:

- Preliminary resource adequacy outlooks
- Acquiring capacity
- Proposed engagement approach

TAB C

EXHIBIT "C"

referred to in the Affidavit of

DAVID SHORT

Sworn October 25, 2019

Commissioner for Taking Affidavits

Resolution of the
IESO Board of Directors

Independent Electricity System Operator

August 28, 2019

In Respect to a Recommendation from the Technical Panel on Market Rule Amendments

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CONCERNING MR-00439-R00: Transitional Capacity Auction

WHEREAS The IESO identified a reliability need to evolve the demand response auction into a more competitive capacity acquisition mechanism that will enable non-committed dispatchable generators to participate in a transitional capacity auction (TCA) alongside dispatchable loads and hourly demand response resources.

WHEREAS The IESO engaged with stakeholders through a formal stakeholder engagement initiative and incorporated several comments into the design and direction of the TCA.

WHEREAS The Technical Panel voted by a 11-1 majority vote to recommend MR-00438-R00 for approval by the IESO Board.

BE IT RESOLVED THAT the Board accept the majority vote and recommendation of the Technical Panel to adopt MR-00439-R00, with an effective date of October 15, 2019.

TAB D

EXHIBIT "D"

referred to in the Affidavit of

DAVID SHORT

Sworn October 25, 2019

Commissioner for Taking Affidavits

Reasons of the *IESO Board* in respect of an *amendment* to the *market rules*

Terms and acronyms used herein that are italicized have the meanings ascribed thereto in Chapter 11 of the *market rules*.

The following sets out the *IESO Board's* reasons for its decision on the proposed *amendment* to the *market rules* identified in Part 1 below (the "**Amendment**").

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR- 00439-R00-R05
Title:	Transitional Capacity Auction

The *IESO Board* convened to consider the Amendment on the date and location set out in Part 2 below.

PART 2 – BOARD MEETING INFORMATION

Date:	August 28, 2019
Location:	120 Adelaide Street, West, Toronto

Prior to considering the Amendment, the Chair of the *IESO Board* enquired whether any director of the *IESO Board* had a conflict of interest to declare, the result of which is set out in Part 3 below.

PART 3 – CONFLICTS OF INTEREST

☒ No conflict was declared.

☐ Any director declaring a conflict of interest abstained from voting on the adoption of the Amendment.

The *IESO Board* was presented with the materials in respect of the Amendment identified in Part 4 below (the "**Materials**"), all of which is *published* on the *IESO's* website subject to such redactions as *IESO* staff determined reasonably necessary.

PART 4 – MATERIALS

- Agenda Item Summary
- Memorandum from the Technical Panel Chair
- IESO Summary Presentation
- IESO legal memo (privileged and confidential, not made publically available)
- Market Rule Amendment Proposals
  - R00 – Changes to Market Rule Definitions
  - R01 – Participant Authorization and Facility Registration
  - R02 – Auction Parameters and Publication
  - R03 – Energy Market Participation
  - R04 – Non-Performance Charges and Settlements
  - R05 – Removal of DR Pilots and CBDR Sections
- Draft Resolution
- Technical Panel member vote and rationale
- Stakeholder Feedback
  - Advanced Energy Management Alliance (AEMA)
  - Association of Major Power Consumers of Ontario (AMPCO)
  - Enel X
  - AEMA / AMPCO joint submission
- Consumer Impact Assessment (this assessment is required to support the Ontario Energy Board market rule amendment review process)
- Technical Panel and Stakeholder Comments (this assessment is required to support the Ontario Energy Board market rule amendment review process)
- IESO email to Rodan and AMPCO, dated August 16, 2019
- Rodan email to IESO (not made publicly available at request of Rodan)

Having considered the Amendment and the Materials, the *IESO Board* decided as identified in Part 5 for the reasons set out in Part 6.

PART 5 – DECISION

☒ The *IESO Board* decided in favour of the adoption of the Amendment.

☐ The *IESO Board* referred the Amendment back to the *technical panel* for further consideration and vote.

☐ The *IESO Board* decided against the adoption of the Amendment.

PART 6 – REASONS

The *IESO Board* reviewed the Materials including the *technical panel* vote of 11 in favour and 1 opposed to recommend MR-00439-R00-R005 for approval by the *IESO Board. The IESO Board* discussed the Amendment at the August 28, 2019 *IESO Board* meeting, including the positions of stakeholders and the issues raised during the market rule amendment process. The *IESO Board* decided to adopt the Amendment, with an effective date of October 15, 2019, based on the following reasons:

1. The Amendment is the first phase in evolving the demand response auction into a more competitive capacity acquisition mechanism that includes new resource types. This allows for increased competition in the acquisition of capacity for the benefit of Ontario customers.

2. The Amendment enables the IESO to begin implementing the Transitional Capacity Auction in a phased approach in order to be ready to address forecasted capacity needs in Ontario. The implementation of the first phase of the Transitional Capacity Auction will enable important experience and learnings with respect to integrating and administering new resource types in the Ontario capacity market sufficiently in advance of more significant capacity needs, currently projected to arise in the 2023 timeframe. A phased approach will reduce risk, while ensuring continued evolution of the market through the phased inclusion of new resources. This is a more prudent approach than attempting to implement a new capacity auction mechanism just prior to the time when there is a more significant capacity need.

3. The Amendment enables non-committed dispatchable generators to participate in the Transitional Capacity Auction alongside dispatchable loads and hourly demand response resources. The Amendment provides an important opportunity for existing non-committed generators coming off contract to compete to provide reliability services, in this case capacity. In the absence of this opportunity to compete, these generators may choose to wind down their operations to the potential detriment of Ontario reliability and the interests of Ontario customers.

The *IESO Board* noted and reviewed the view of some stakeholders that the Amendment would unjustly discriminate against demand response resources because those resources would not receive an additional payment if they are economically activated (comparable to the energy payment to generators). The *IESO Board* considered the AEMA/AMPCO joint brief dated July 19, 2019 and concluded that the current Amendment does not unjustly discriminate against demand response resources.

The position of the stakeholders relies heavily on a Final Rule issued in March 2011 by the United

States Federal Energy Regulatory Commission (FERC) which requires payments to demand response resources when they are dispatched subject to the condition that they meet a "net benefit requirement". This FERC Rule is a relevant consideration, but the Board was advised it is not binding in Ontario. More importantly, it is not clear that the FERC analysis and conclusion is applicable to Ontario given the differences in the Ontario electricity market as compared to United States electricity markets. For example, it is not clear whether an additional payment to demand response resources in Ontario would meet the FERC net benefit requirement.

As a result, further analysis is required, and the IESO has already committed to completing that analysis and engaging stakeholders in this process. AEMA/AMPCO believe it is appropriate to delay implementation of the auction in order to complete the analysis. The analysis is expected to take some time which would delay the planned Transitional Capacity Auction. The *IESO Board* considered a delay and concluded that a delay is not warranted and, further, would undermine the benefits noted above and be detrimental to the market overall.

In addition, access to energy payments is not expected to be a material consideration for the December 2019 auction, because economic activations are expected only under very limited circumstances, which is also consistent with the level of historical economic activations. As noted above, the IESO has committed to studying the impact of introducing energy payments for demand response resources in Ontario and if such payments are warranted they could be introduced in a subsequent phase of the capacity auction. The *IESO Board* concluded that proceeding with the Amendment and the auction would not cause substantial harm to demand response resources.

The *IESO Board* also concluded that delaying the auction in order to complete the analysis would be detrimental to the market overall. Specifically, delaying the auction would delay the introduction of increased competition, create an unnecessary delay in the phased approach to developing the auction in advance of substantial future capacity needs, and risk failing to retain access to existing generation assets coming off contract. A delay would therefore result in decreased competition in Ontario and give rise to potential negative impacts on reliability.

The *IESO Board* concluded that it is prudent to implement the Amendment as proposed. The *IESO Board* noted that the *technical panel* also considered these issues and concluded (by a vote of 11 in favour and 1 opposed) that the Amendment should be recommended for approval. Much of the rationale of those supporting the Amendment is reflected in the *IESO Board's* reasons for approving the Amendment.

Lastly, relating to a *technical panel* process matter, the *IESO Board* noted that the AEMA/AMPCO joint brief was provided to the *technical panel* shortly before its August 13, 2019 meeting and the issue was raised as to whether the *technical panel* had sufficient time to consider the brief. The *technical panel* was provided an opportunity to delay the vote if members required more time to consider the joint brief, but the *technical panel* decided not to delay the matter. The *IESO Board* reviewed all the *technical panel* Materials and concluded that the *technical panel* exercised its discretion on an informed and reasonable basis.

TAB E

EXHIBIT "E"

referred to in the Affidavit of

DAVID SHORT

Sworn October 25, 2019

Commissioner for Taking Affidavits

Technical Panel – Rationale

Proposed Rule Amendments –Transitional Capacity Auction, Phase 1

On August 13, 2019, the Technical Panel voted in favour of recommending the following draft market rule amendments for consideration by the IESO Board.

Re: MR-00439-R00-R05: Transitional Capacity Auction, Phase 1

The following is the TP member vote with supporting rationale:

In favour: Robert Bieler, Ron Collins, Sarah Griffiths, Robert Lake, Phil Lasek, Robert Reinmuller, Sushil Samant, Joe Saunders, Jessica Savage, Vlad Urukov, Julien Wu
Opposed: David Forsyth

TP Member	**Rationale to Support Vote**
Bieler, Robert Representing: Consumers	The amendments as reviewed by the Technical Panel have been offered for stakeholder input and in my view the language reflects the intent of the policy approach for the Transitional Capacity Auction. I believe that implementing the capacity auction will provide greater competitiveness in the market and therefore benefits to consumers. While this approach may not be preferred by all stakeholders, this is transitional by definition and as such will evolve over time. There will be future opportunities to amend the Market Rules to address additional concerns should they arise.
Collins, Ron Representing: Energy Related Businesses and Services	I support the Market Rule amendments proposed by the IESO staff for the Transitional Capacity Auction. The proposed Market Rule amendments support the development of a capacity market to address future resource adequacy and increase flexibility in the IESO-administered market. Such amendments will encourage broader competition for establishment of capacity in a transparent and cost-effective manner.

Forsyth, David Representing: Market Participant Consumers	I voted against the TCA proposed rules based on the fact that in my opinion the TCA design is fundamentally flawed without including the energy payment element for loads, and therefore discriminates against some market participants. I believe this violates the Electricity Act. The basis for this opinion is included in the joint submission from AMPCO and AEMA.
Griffiths, Sarah Representing: Other Market Participants	I voted today to approve the MRA for the Transition Capacity Auction as I have long advocated for markets and competition for the IESO to meet the capacity needs. However, without resolving how demand response resources are compensated for the value they provide to the IESO is an issue, and undermines the competition in this auction. Many DR Market Participants do not agree with the approval of the MR and asked me to vote against or abstain, and DR participants continue to ask the IESO to postpone the first Auction at least 6 months until this issue is resolved. Both AEMA and AMPCO have provided a legal brief to IESO staff that outlines how a TCA without resolving issues regarding just and reasonable compensation to DR resources is discriminatory. My vote is based on the acknowledgement that the IESO staff have outlined, at the DRWG, a path forward and that they continue to engage with market participants/interested parties on this topic. The DR resource is a valuable resource to the overall electricity system but it needs to be treated in a comparable manner to ensure the ratepayer and the system receive its true value.
Lake, Robert Representing: Residential Consumers	Representing consumers, I want our electricity system to develop into one where we have what economists call pure competition. If we would have had numerous suppliers competing at the time of deregulation we probably would have a competitive, mature electricity market today, like Sweden and Norway. While we might not initially get all details perfectly correct with this proposal, there will be accommodation to make changes in the future, after we have had some experience with TCA. This is one good step towards developing an efficient, competitive electricity market.
Lasek, Phil Representing: Market Participant Consumers	Generally supported the shift to a different program, adding that it might not be optimal but was still in the interest of power consumers.

Reinmuller, Robert Representing: Transmitters	I reviewed the comments provided and while feedback on behalf of DR participants has points that will need consideration, it was clear in the IESO plans that the DRA will evolve into the TCA and therefore due consideration will be made while finalizing the ultimate construct. In an attempt to ensure the system is adequately prepared to meet future needs continued progress has to ma made now and consideration for DR will have to be integrated as we develop the ultimate market construct. DR resources that are traditional load customers have been connected to the grid on the basis of their electricity needs at the time and as such, transmission, distribution and generation infrastructure was developed to meet their demand over a number of years. In most cases investments in the system are amortized and recovered through rates over a long period of time. When we discuss DR and equivalency with generation a more in-depth study needs to be undertaken to fully understand how existing upstream infrastructure investments (generation and system) are affected by DR. The current market takes into account the system needs and provides multiple quantifiable ways to fulfill capacity and energy requirements. As we transform to better integrate DR, DER, storage, load displacement etc., we must ensure that we can guarantee the long term viability of the solution, while quantifying the exact value of each resource in the overall context of the system need. Critical elements like voltage control, frequency control, phase angle, inertia, response time, etc. will need to be reviewed along with regulating local load quantities. As AMPCO indicated, a “reliable and affordable energy supply is critical” and we can only achieve that goal with thoroughly quantifying the value proposition of all critical resources included in the TCA. I trust that IESO will follow through with including DR and other existing and new resources into the ultimate TCA construct. This is why I vote yes to recommend sending the TCA MR amendments to the IESO BOD for consideration.
Samant, Sushil Representing: Market Participant Generators	• The immediate implementation of the TCA will assist the IESO in its goal of Reliability • Increased competition in the TCA will put downward pressure on the capacity auction clearing prices, which is of interest to Ratepayers • The MRAs associated with the TCA have been thoroughly discussed and comments received at the appropriate Stakeholder Engagement(s) o The IESO is in the process of making changes for the use of Utilization Payments for out-of-market activations for Hourly Demand Resources (HDR).

	○ The IESO has agreed to further stakeholder the use of Utilization Payments for in-market or economic activations of all Demand Response (DR) resources. ○ The issue concerning compensation to DR resources for economic activations is a wider market issue that would require years of stakeholdering and has implications for the entire design of the Ontario's electricity market (energy and capacity). As a result, it is not worth holding up this worthy TCA initiative for an issue that will most likely end up having little relevance or merit after further study (see my note below). ○ Furthermore, there has been a non-material amount of economic activations of DR resources in the past. It is anticipated that this will continue into the near future. This weakens the argument that the TCA initiative is flawed. • As a result, I feel that the MRAs reflect the intent of the design as contemplated in the Stakeholder Engagement(s) • The MRAs are a proper fit with other Market Rules *Note:* The legal brief submitted by AMPCO/AEMA and made public by the IESO on August 12, 2019 further solidified my decision to vote in favour. This is because its main argument for delaying the TCA so that the IESO could address the issue of compensation to DR resources seemed to rely on Item 33 (Page 6) which discusses the basis upon which FERC made its March 2011 Order. In particular, the recommendations in FERC Order No. 745 as described in the legal brief hinge on the condition that there is a positive "net benefits test" which measures the "billing unit effect" when dispatching DR resources. I felt that in Ontario, this threshold requirement of a positive "net benefits test" is not met. My reasoning was that while costs (i.e. HOEP or MCP) would be reduced when dispatching DR resources, there was a commensurate increase in end user rates as fewer units are consumed. This increase in end user rates is the result of the Global Adjustment increasing whenever the price of electricity (i.e. HOEP or MCP) decreases. In effect, while fewer MWhs would be consumed as a result of DR, the fixed costs of maintaining the electricity system are still the same. This results in an increase to what FERC refers to as the billing unit effect.

	As a result, I believe the requirement of a positive "net benefits test", if similarly adopted in Ontario, would not be met.
Saunders, Joe Representing: Distributors	The proposed amendments reflected the evolution of the existing market, and were important to the system as a whole. He acknowledged the concerns raised by market participants, but said he supported the package as a first step, on the understanding that the IESO will take stakeholders' concerns into account.
Savage, Jessica Representing: IESO	The proposed Market Rule amendment is a "first step towards enabling competition to provide reliability services, in this case, capacity. Building on the existing DR auction and enabling additional resources to compete now is a prudent approach to maximizing future participation when a more significant capacity need emerges in several years' time.
Urukov, Vlad Representing: Market Participant Generators	The Market Rule amendment package presented to the Technical Panel reflects solely the implementation of the first phase of a staged approach transitioning the existing Demand Response Auction to a more competitive auction process. The Market Rule package was *stakeholdered* in a dedicated stakeholder engagement and reflects feedback provided by participants. In my assessment, the proposed Market Rules reflect the intent of broadening participation by enabling auction bidding of uncommitted, dispatchable generators, while retaining all features and functionality required by Hourly Demand Response (HDR) and dispatchable loads to continue to participate. In addition, the proposed rules appropriately retain features essential for the execution and settlement of the remaining commitments associated with the last Demand Response auction. With consideration given to the submissions by AMPCO and AEMA, I support implementing the proposed Market Rule amendments as drafted on the following basis: The IESO has demonstrated and reaffirmed that based on history, existing Demand Response Auction participants have not been utilized materially over and above out-of-market activations for testing. The IESO is in the process of addressing out-of-market activations through ongoing stakeholder engagement, targeting an implementation in advance of the first auction held under the proposed new rules. The assessment of the appropriateness of other forms of payments is a complex question that must consider a wide range of economic aspects across the breadth of applicable costs and supplier types. The IESO has committed to evaluate and report on an appropriate path forward in the context of the Ontario market in subsequent phases of auction development. While I support and encourage the IESO to ensure that the issue is addressed in a thorough and transparent fashion, this effort need not delay the implementation of the proposed set of Market Rules.

Wu, Julien Representing: Wholesalers	The proposed Market Rule amendments are necessary and important for planning and reliability, with the Transitional Capacity Auction coming into force very quickly. However, the deliberation has been reminiscent of the discussion initiated previously by Resolute Forest Products, where it felt as though nothing had been resolved in the end because both the substance and the process were so complex. In that instance, there was a dispute resolution going on in parallel with the Technical Panel discussion. Julien voted in favour of the draft amendment so that the concerned parties would not have its resolution process held up by the Panel, and could take the matter forward to the Board if they so choose as a next step.

TAB F

EXHIBIT "F"

referred to in the Affidavit of

DAVID SHORT

Sworn October 25, 2019

Commissioner for Taking Affidavits

UTILIZATION PAYMENTS FOR DR ACTIVATIONS

Demand Response Working Group

Gordon Drake

May 11, 2017

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Overview

- The 2017 work plan includes a discussion on whether to provide utilization payments for DR resources when they are activated/dispatched
- This issue has been discussed in previous design discussions and DR resources do not currently receive utilization payments
- The IESO will be engaging an independent consultant with expertise in DR and electricity markets to study the issue

Request for Stakeholder Input

- The IESO would like to ensure that the independent consultant considers a variety of viewpoints both for and against utilization payments for DR
  - Stakeholder input into these viewpoints will help inform a complete assessment of the issue
  - In order to gather these viewpoints, the IESO is requesting feedback from DRWG members on issues which may have arisen since the last time the topic was discussed

Request for Stakeholder Input (cont'd)

- Participant submissions will be used to inform the scope presented to the independent consultant in carrying out this study
- The consultant may request further stakeholder input through the course of undertaking the study
- The consultant may also come to a future DRWG meeting to solicit feedback or present findings
- Input should be sent to engagement@ieso.ca by **May 19th**

TAB G

EXHIBIT "G"

referred to in the Affidavit of

DAVID SHORT

Sworn October 25, 2019

Commissioner for Taking Affidavits

Utilization Payments – 2017 Work Plan Item

Demand Response Working Group

Gordon Drake

May 30, 2017

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Utilization Payments - Background

- *Utilization Payments has been a recurring topic of discussion by stakeholders in the DRWG and has been included in the 2017 Work Plan as a discussion item*
- *The IESO has committed to explore the merits of Utilization Payments by engaging an independent consultant. The consultant will be expected to put forth their findings in a discussion paper and present this at a DRWG later in the year*
- *The IESO has asked stakeholders for input into potential topics to be included in the scope of the discussion paper*

Stakeholder Views

At the May 11th webinar, the IESO asked stakeholders to share their views on their perspectives on utilization payments for DR

- Introducing Utilization payments adds extra incentive, particularly for residential DR participants and would increase the likelihood of activations
- Support for Utilization Payments and point to the fact that other Markets across North America have introduced this
- From a Market Renewal perspective the IESO should ensure that all resources are treated comparably in the development of the Incremental Capacity Auction, including compensation for the MW's they deliver
- Believe that dispatch of Hourly DR resources would increase with Utilization Payments as participants reduce their bid prices to account for the additional revenue incentive

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Discussion Paper Scope

- Economic efficiency arguments for and/or against providing utilization payments for DR
- Past practice in Ontario market, practices are adopted in other markets
- Whether changes in the market warrant a utilization payment for certain (or all) resources
- Impact a Utilization Payment would have on the wider market, and in particular any positive or negative influence on the outcome of the Incremental Capacity Auction
- Whether providing a utilization payment would increase the frequency of HDR dispatch and the resulting efficiency impacts

Next Steps

- The IESO will issue a request to an external consultant or firm to draft the discussion paper
- The consultant will prepare the discussion paper, which may involve working with participants through the DRWG and, potentially, directly
- In the interest of moving forward, participants are asked to identify any outstanding scope items by June 7, 2017 to engagement@ieso.ca

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TAB H

EXHIBIT "H"

referred to in the Affidavit of

DAVID SHORT

Sworn October 25, 2019

Commissioner for Taking Affidavits

DEMAND RESPONSE DISCUSSION PAPER

UTILIZATION PAYMENTS

NOVEMBER 16, 2017

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INTRODUCTION

- IESO has retained Navigant to review the arguments for and against utilization payments, as well as explore the impacts this might have to the wider market.
- The following slides provide a summary of that work and a jurisdictional scan.

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ARGUMENTS FOR AND AGAINST UTILIZATION PAYMENTS

PAYMENT STRUCTURES

There are two payment types for DR resources: availability (per MW) and utilization (per MWh) DR resources may receive either or a combination of both

Availability Payment

- Fixed daily, monthly, or annual payment made to DR resources in exchange for the guarantee that they will be ready to curtail their load when called upon
- Typically compensates DR provider for fixed costs associated with providing the service
- In most jurisdictions, including Ontario, availability payments are used for reliability/capacity DR

Utilization Payment

- Payment made to DR resources when they are called upon to modify their load.
- Typically based on the actual level of curtailment
- Generally intended to compensate DR resources for the variable (marginal) costs associated with providing the service
- In most regions, utilization payments are used for DR that provide economic/energy DR

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ARGUMENTS FOR AND AGAINST UTILIZATION PAYMENTS

There are common arguments for and against providing a resource with a utilization payment. The arguments can be categorized as follows:

ARGUMENTS AGAINST	ARGUMENTS FOR
Wholesale Price Efficiency	Reducing Consumer Costs
Disproportional Benefits	Disconnect between Wholesale and Retail Prices
Harm to Other Suppliers	Fairness
Harm to Economy	Other Costs Associated with Curtailment

Each argument has merit, although materiality can vary

What follows are general descriptions of each argument and the underlying rational, they are not intended to be a statement of position or fact

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ARGUMENTS AGAINST UTILIZATION PAYMENTS

Wholesale Price Efficiency

- *Real-time wholesale energy prices are an efficient price signal because they match supply and demand based on bids and offers on a minute-by-minute, hour-by-hour basis, and introducing an additional payment could create an inefficiency in the market because dispatchable loads would receive an out-of-market payment that could alter their bid/offer strategy.*

Considerations for Ontario: Argument only applied to loads that receive the wholesale energy price

Disproportional Benefits

- *Providing a utilization payment compensates a DR resource disproportionally relative to a supply resource, because the DR resource did not incur a cost associated with the production of electricity, as such a DR resource should be treated as if it had first purchased the power it wishes to resell to the market*

Considerations for Ontario: Argument is based on a premise that a megawatt of electricity curtailed (negawatt) is not equivalent to a megawatt of electricity
Argument assumes the cost of curtailment (or the value of lost load) for a DR resource is immaterial

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ARGUMENTS AGAINST UTILIZATION PAYMENTS

Harm to Other Suppliers

- *Utilization payments will result in downward pressure on wholesale energy prices because DR resources are able to bid into the energy market at prices lower than traditional supply and will be dispatched more frequently*

Considerations for Ontario: To have a material impact on energy prices, utilization payments would have to result in a considerable increase in activation

Under the current market structure in Ontario, most generators are under contract or receive regulated rates and hence have a high degree of revenue or price certainty

Harm to Economy

- *Providing utilization payments will incentivize loads to reduce production in order to provide demand reductions into the electricity market, reducing supply of other goods in the economy and increasing prices*

Considerations for Ontario: Argument only valid for supply constrained and non-trade exposed sectors of the economy where prices are set based on local supply and demand

Ontario has a diversified and open economy that responds effectively to changes in supply

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ARGUMENTS FOR UTILIZATION PAYMENTS

Reducing Consumer Costs

- *Utilization payments will increase the level of DR participation and activation, which is a less expensive form of capacity and energy than traditional supply resources, and hence will result in lower consumer costs*

Considerations for Ontario: To have a material impact on capacity or energy prices, utilization payments would have to result in a considerable increase in levels of participation and activation
Under the current market structure in Ontario, most generators are under contract or receive regulated rates and hence consumer costs are largely fixed

Disconnect Between Wholesale and Retail Prices

- *Retail prices don't reflect the real-time fluctuations in the cost of electricity and are inefficient and utilization payments are a way of improving the economic efficiency of the retail price by providing an additional financial incentive during high-price events*

Considerations for Ontario: Argument only valid for customers on retail rates and not exposed to real-time energy prices

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ARGUMENTS FOR UTILIZATION PAYMENTS

Fairness

- *Generation resources receive a utilization payment in the form of an energy payment when they produce electricity and DR resources should be treated fairly and receive a utilization payment when they curtail electricity*

Consideration for Ontario: Argument is based on the premise that a megawatt of electricity curtailed (negawatt) is equivalent to a megawatt of electricity

Other Costs Associated with Curtailment

- *There is a cost associated with curtailing demand (or producing a negawatt of electricity), which is equal to the* ***value of lost load****, which can be higher than the avoided cost of electricity, utilization payments compensate DR resources for these costs*

Considerations for Ontario: For large commercial and industrial customers, the value of lost load can be very high, which could result in limited activation of DR resources regardless of whether utilization payments are offered

WIDER MARKET IMPACTS

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WIDER MARKET IMPACTS

Introducing utilization payments for DR can have both direct and indirect impacts on the Ontario electricity system.

Direct Impacts (Impacts to Power Markets)

- DR resources change their bids into the energy market and are activated more often
  - This would occur is Value Of Loss Load for DR resource was below system cap
- DR participation increases in both the capacity (i.e. DR auction) and energy markets
  - This would occur is Value Of Loss Load for DR resource was below system cap

Indirect Impacts (Secondary Impacts on Power Markets and Outside Power Markets)

The following indirect impacts assume direct impacts occur

- Energy prices, particularly during price spikes, likely decrease
- Capacity prices change, difficult to estimate but likely decrease minimally
- DR resources likely receive higher revenues
- System costs change, difficult to estimate but likely decrease minimally
- Production levels of goods in the economy likely decrease minimally

The indirect impacts are uncertain, what are presented above are first order impacts which would follow if the direct impacts occur. Interactive effects may also occur.

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WIDER MARKET IMPACTS – DIRECT IMPACTS

DR resources change their bids into the energy market and are activated more often

- With utilization payments, DR resources would have an incentive to bid values lower than the ceiling price into the energy market as they would receive payment whenever they are activated.
- Each participating resource would have to determine the value of consuming electricity relative to their avoided cost plus the utilization payment and use that to define their bid into the market.
- Experience in other markets has shown that the impact is likely to be small for traditional DR providers but as technologies change, expanded capabilities and changing business models may result in larger impacts on bidding strategies.

DR participation increases in both the capacity and energy markets

- With the additional incentive of utilization payments, there may be increases in the amount of DR that enters the Ontario system.
- The magnitude of this impact depends on whether there is a material increase in revenue for traditional DR or if there are viable new business models that can rely on the changed incentives.

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WIDER MARKET IMPACTS – INDIRECT IMPACTS

Energy prices, particularly during price spikes, decrease

- If the utilization of DR resources increases, there will be downward pressure on energy prices.
- Impact depends on whether DR resources change their bids to be below the ceiling price or if there is significant new entry of DR resources due to the changed incentives.
- If neither of these conditions is true, then the impact on energy prices will be minimal.

Capacity Price Changes

- If DR participation in the market increases and it can meet capacity obligations, then there could be reduced need for other capacity resources. This would put downward pressure on capacity prices.
- However, reduced energy prices increase the net revenue requirement of traditional resources and they would likely increase their bids into the capacity market which could put upward pressure on capacity prices.
- The relative impacts of these two dynamics is difficult to estimate.

WIDER MARKET IMPACTS – INDIRECT IMPACTS

DR Resources Receive Higher Revenues

- With an additional source of revenue, DR resources would likely receive higher overall revenues.
- For current market participants, even if they do not change bidding strategies, they would add utilization payments when prices reach the ceiling and they are dispatched.
- The caveat to the higher revenues is whether there is a reduction in availability prices that offsets the utilization payments.

System Costs Change

- Each of the indirect dynamics discussed above change the overall system cost.
- Incremental activation payments to DR providers would increase costs. Decreases in capacity and energy prices would decrease costs. It is challenging to estimate the relative magnitude of the impacts.
- If utilization payments are, but the mix and level of DR participation and activation remains the same, then the overall ***impact of the change would be minimal***. However, if the change resulted in a large increase in participation and activation remains the same, then the overall impact of the change then the incentives ***could be a material reduction in system costs***.

WIDER MARKET IMPACTS – INDIRECT IMPACTS

Production Losses

- With the additional source of revenue some DR resources may be incented to bid into the energy market at lower prices leading to more frequent curtailment.
- This could lead to declines in the domestic production of other goods, which in turn could change the price of these goods in the economy.
- These impacts are expected to be minimal, as jurisdictions that added or increased utilization payments did not realize a significant increase in the activation levels of DR.

JURISDICTIONAL SCAN

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TYPES OF DEMAND RESPONSE

DR is a common resource in organized wholesale power markets. In jurisdictions reviewed, participation in reliability programs is higher than economic programs.

	Economic/Energy	**Reliability/Capacity**
Receives availability payment	No	Yes
Receives utilization payment	Yes	Maybe
Voluntary availability	Yes	No

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JURISDICTION SCAN OVERVIEW

Navigant reviewed markets that have a history of DR, ideally within a power market framework.

- In many jurisdictions, the same DR resource can participate in ***both an economic/energy and reliability/capacity*** programs at the same time, which allows them to collect both availability and utilization payments.
- DR can participate in ancillary service markets in many jurisdictions, however, the requirements for these markets are very specific and the use of utilization payments in these markets is widely accepted.
- Jurisdictions reviewed were selected to cover diverse geography, payment structures, and payment levels
    - PJM
    - Texas (ERCOT)
    - NY
    - California
    - Australia
    - Finland
    - France
    - South Korea

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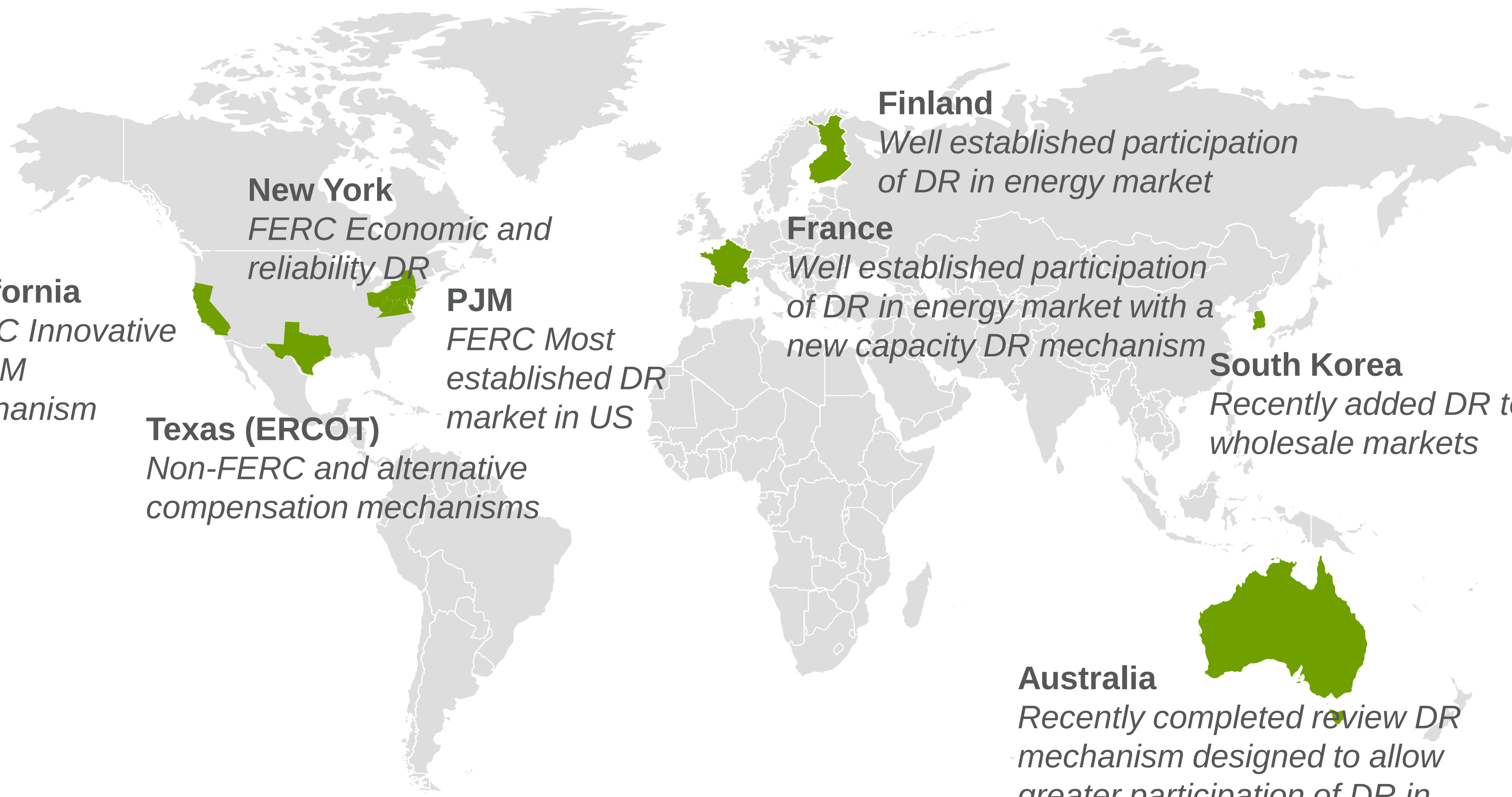
JURISDICTION SCAN OVERVIEW



California
FERC Innovative DRAM mechanism

New York
FERC Economic and reliability DR

PJM
FERC Most established DR market in US

Texas (ERCOT)
Non-FERC and alternative compensation mechanisms

Finland
Well established participation of DR in energy market

France
Well established participation of DR in energy market with a new capacity DR mechanism

South Korea
Recently added DR to wholesale markets

Australia
Recently completed review DR mechanism designed to allow greater participation of DR in markets

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JURISDICTION SCAN – RELIABILITY/CAPACITY DR

Navigant examined the features of reliability DR across all jurisdictions

- **Similarities:** provided an **availability payment** in exchange for the ability to use DR in a reliability event.
- **Differences: Also may receive utilization payments** when activated.

Key Points:

- Resources are **dispatched manually**, not by SCED
- When activated, reliability DR resources may also be **paid a utilization payment** (occurs in all jurisdictions reviewed excluding ERCOT).
- For NYISO and PJM, **participation in the reliability DR programs is significantly higher than participation in the economic DR programs**

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JURISDICTION SCAN – ECONOMIC DR

Navigant examined the features of economic DR across all jurisdictions

- **Similarities:** required to bid directly into market; dispatched using ISOs' security constrained dispatch algorithm.
- **Differences:** Do not receive availability payment, receive utilization payments

Key Points:

- ***Utilization payments*** provided in all jurisdictions
- Magnitude of the utilization payment has been debated (e.g. wholesale clearing price vs. wholesale clearing price less cost of generation)
  - Jurisdictions reviewed provide wholesale clearing price however FERC jurisdictions have argued that LMP-G is more appropriate
- Variation in participation and activation levels
  - ***Participation has been lower in economic*** than reliability DR programs in jurisdictions reviewed
- Some jurisdictions have a ***floor price for DR*** bidding into the wholesale energy market (FERC Order No. 745)

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JURISDICTION SCAN – DR PAYMENT MOTIVATIONS

All jurisdictions provide an availability payment for reliability/capacity DR. Where possible, Navigant also examined the reasoning for economic DR payment types.

FERC Jurisdictions

- In 2011, the FERC in the US ruled that DR resources bidding into the Day-Ahead and Real-Time energy markets should be paid the full locational marginal price (LMP) like other generation resources bidding into the markets.
- This set a requirement for California, NYISO and PJM to provide utilization payments equivalent to LMP.
- These payments are provided for energy only DR and also for reliability DR when it is activated.
- All three jurisdictions opposed FERC Order No. 745 and have suggested that LMP minus generation is a more appropriate payment level.

Non-FERC Jurisdictions

- In Australia and South Korea (where Navigant was able to complete interviews) payments are equivalent to the spot price. This incentive level was reported to have been selected based on fairness, since the DR resources are participating in the energy market like other supply resources
- In South Korea resource which also participate in a reliability/capacity DR program receive both availability payment (requiring them to be available) and utilization payments for energy DR participation
- ERCOT has a program similar to Ontario which provides an availability payment in exchange for the requirement to bid into the energy market. They have not had any participation in the program since 2014.

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JURISDICTION SCAN –DR PARTICIPATION SUMMARY

Seven of the eight jurisdictions reviewed have economic DR. Lower participation in economic DR may indicate that utilization payments are not high enough to incent resources to curtail.

Jurisdiction	Economic Participation	Reliability Participation
California	160 MW	200 MW under contract for 2018/19
NYISO	0 MW (No bidding activity since 2010)	1,192 MW 2016
Mid Atlantic US (PJM)	2,096 MW in 2017 (decreasing or stagnant)	9,123 MW 2016
France	1.522 GWh (2015) and 10.313 GWh (2016)	N/A
Finland	200-600 MW Day-Ahead; 0-200 MW Intraday	N/A
South Korea	Unknown	3,885 MW 2016
Texas (ERCOT)	N/A	Only 3 events since 2008
Australia	Unknown	N/A

TAB I

EXHIBIT "I"

referred to in the Affidavit of

DAVID SHORT

Sworn October 25, 2019

Commissioner for Taking Affidavits

Demand Response Discussion Paper

Utilization Payments

Prepared for:

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December 18, 2017

Disclaimer

This report was prepared by Navigant for the Independent Electric System Operator.

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1. INTRODUCTION

This paper was drafted to provide context and research on utilization payments and inform a dialogue on their possible merits to drive additional, economically efficient, curtailment of loads to meet a variety of electricity system needs. This discussion paper includes a review of practices in other jurisdictions, arguments for and against providing a utilization payment to demand response (DR) resources, a qualitative assessment of the potential impact of utilization payments on the dispatch frequency of DR resources in Ontario, and a qualitative assessment of the effect of any changes in payment structure on the wider market. ***This paper focuses solely on economic (i.e. energy) and reliability (i.e. capacity) DR that is linked to an organized wholesale power market and the question of economic efficiency relative to the status quo in Ontario.***

There is disagreement about the efficiency and fairness of allowing a single DR resource to capture both energy (utilization) and capacity (availability) payment streams.[1] At the broadest level, proponents of both payments for load resources argue that calling on a DR resource to curtail provides incremental value to the power system, and these load reductions should be compensated through utilization payments much like a generation resource participating in both capacity and energy markets. Opponents argue that the availability payment adequately compensates a DR resource for providing capacity and that utilization payments are a form of double payment as the DR provider receives a benefit in terms of its avoided cost of electricity when it is utilized. This paper will discuss these and other arguments for and against both availability and utilization payments.

DR has been part of the Ontario electricity system since the early 2000s. Dispatchable load resources were active in the IESO-administered market since the market open in 2002. In 2007, the IESO (former OPA) recognized that there was capacity value from demand-side resources and started the DR3 program. DR resources were procured through multi-year standard offer contracts in the DR3 program. The DR3 program included availability payments and utilization payments. In December 2015, the DR programs were integrated into the IESO-administered wholesale power market with the advent of the DR auction.

The DR auction procures DR resources as reliability/capacity resources. Participants offer into two seasonal DR auctions. Participants who clear the auction are required to be available to the IESO to meet peak demand. As part of this, they have a requirement to bid into the real-time energy market between a price floor of $100 and price ceiling of $1999.99 for each business day during the season. A DR resource is dispatched through the IESO's security constrained dispatch algorithm and is curtailed when economic in the seasonal activation window. Availability payments are made to DR resources that clear in the DR auction regardless of how often they are dispatched to curtail. DR resources participating in the DR auction do not receive an additional utilization payment when they are dispatched.

For some wholesale customers, the opportunity cost of curtailing load in any individual hour is higher than the IESO ceiling price. They participate in the market mainly to receive capacity payments. The main impact of this dynamic is that DR resources in Ontario tend to bid into the energy market at the ceiling price to minimize their utilization and are seldom called upon to curtail.

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[1] DR also participates in ancillary service markets in a number of jurisdictions, however, the use of utilization payments in these markets is widely accepted and outside the scope of this report.

It is important to note that Ontario is different from many U.S. jurisdictions in that many of the DR resources are wholesale market participants or large customers that are exposed to real-time electricity prices as opposed to retail prices. This means that Ontario DR customers avoid the entire real-time electricity price when curtailing and are exposed to high price spikes. When DR providers are only exposed to retail rates as they are in many U.S. jurisdictions, they are unlikely to have the same avoided cost benefit when curtailing during spikes in prices.

2. BACKGROUND AND DEFINITIONS

This section outlines four levels of considerations that should be reflected upon when discussing DR program or market design. The first is the type of DR resource sought. The second is the payment structure used to compensate the DR resource. The third is the mechanism to establish the payment level for each of the payment structures. The fourth is the evaluation or decision criteria used to assess the tradeoffs between different options.

2.1 Types of DR

DR resources are generally categorized into three different classes.

- ***Economic / Energy***: Economic DR is a commitment to reduce consumption when productive or convenient. Economic DR resources are typically dispatched based on an hourly bid price. These resources do not receive availability payments in the jurisdictions reviewed.

- ***Reliability / Capacity***: Reliability DR is a firm commitment to reduce consumption during times of scarcity or system contingencies. Reliability DR resources are typically dispatched manually. These resources receive an availability payment in exchange for being available to curtail. Ontario is unique, in the sense that reliability DR resources are dispatched through the IESO's dispatch algorithm.

- ***Ancillary services***: Ancillary services DR is the provision, by load, of specialty services that are essential to the secure operation of the system for example operating reserve and frequency regulation.

In many jurisdictions resources can participate in more than one of these DR program. For example, in PJM DR resources can participate in both the economic and reliability DR programs and in Ontario dispatchable loads which are a type of economic / energy can also participate in the 10-minute and 30-minute operating reserve markets.

2.2 Payment Structures

There are two basic payment structures for DR resources. DR resources may be provided with an availability payment, a utilization payment, or a combination of both.

- ***Availability payment***: A fixed daily, monthly, or annual payment made to DR resources in exchange for the guarantee that they will be ready to curtail their load when called upon. Typically, this payment compensates the service provider for the fixed costs associated with providing the service. In most jurisdictions, including Ontario, availability payments are used for reliability/capacity DR.

- ***Utilization payment***: A payment made to DR resources when they are called upon to modify their load. Payments are typically based on the actual level of curtailment. Utilization payments that are based on a market price are often referred to as energy payments.[2] Utilization payments

[2] Note that in U.S. jurisdictions, utilization payments are almost always tied to the energy market and it is broadly accepted to refer to them as energy payments. This framework is driven by FERC Order No. 745.

are generally intended to compensate DR resources for the variable (marginal) costs associated with providing the service. In most regions, utilization payments are used for DR that provide economic/energy DR.

2.3 Payment Levels

Payment levels for both availability and utilization payments can be set in several ways. Utilization payments are typically set administratively, through a pay-as-bid process, or tied to wholesale energy prices.

- ***Administrative Payments***: The level of payment is determined by the program or market administrator and incorporated into the contract with a DR resource or DR program rules. This type of utilization payment is usually not provided to DR resources participating in the power markets. For example, in the previous DR3 program in Ontario, resources were paid an administrative payment ($200/MWh) when they were activated.

- ***Pay-As-Bid:*** The level of payment is determined by each individual DR resource's bid or offer price. In some cases, DR resources include a pay-as-bid price in their bids which if activated they are paid. This is a model used in some jurisdictions where resources receive utilization payments for reliability DR activation. It can also be used as payment structure for resources who are activated through a DR program rather than through participation in power markets.

- ***Wholesale Energy Price:*** The level of payment is determined by the market clearing price in a wholesale energy market. In 2011, FERC Order No. 745 stipulated that DR resources participating in organized wholesale energy markets should receive a utilization payment equal to the Locational Marginal Price (LMP). The LMP reflects the value of energy at the specific location and time it is delivered. A more detailed description of the FERC Order and associated arguments has been included in Appendix B.

- ***Modified Wholesale Energy Price:*** An alternative to the market clearing price, resources may receive is an adjusted market clearing price, where the market clearing price is modified by some factor. An example of a modified wholesale energy price payment is LMP-G which is the market clearing price minus the retail price or in call terminology the spot price minus the strike price. FERC Commissioner Moeller in his dissenting opinion in Order No. 745 argued that paying LMP results in DR resources being overcompensated by the amount of the retail generation rate and paid more than a generator would in providing energy. He argued for a modified rate of ***LMP minus the retail generation rate***.[3]

2.4 Evaluation Considerations

Compensating DR resources that provide capacity through availability payments is broadly accepted. However, there is significant disagreement on whether DR resources should receive a utilization payment when they are curtailed. Historically, utilization payments have not had a large impact on DR participation

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3 http://www.bostonpacific.com/back-basics-demand-response-compensation/

levels (i.e. the amount of DR registered or contracted) or activation levels (i.e. how often it is curtailed). However, new technologies such as energy storage and the improving economics of distributed energy resources present an opportunity for additional DR participation and the payment structure for these types of DR resources needs to be considered more thoroughly.

There are many different criteria that can be used to evaluate trade-offs between payment structure and payment level decisions.

- **Economic Efficiency:** The efficiency of a power market is frequently evaluated using three concepts of efficiency.

  Productive efficiency (also called technical efficiency) occurs at a specific point in time if a given level of output is produced with the least amount of inputs. The Ontario electricity market achieves productive efficiency if the least cost resources are dispatched to meet demand.

  Allocative efficiency occurs at a specific point in time if resources are allocated in a way that maximizes the gains from trade or the net benefit attained through their use. This occurs when the social marginal benefit of the last unit produced equals its social marginal cost. In the wholesale market, the social marginal cost would include, for example, the marginal cost to produce the energy plus the marginal cost of emissions. In the Ontario market, allocative efficiency is largely about getting the price right for consumers so that they can make efficient consumption decisions.

  Dynamic efficiency is concerned more with the pace of investment and innovation in a market. It involves efficient technology choice and timely and efficient capacity investment decisions both on the supply side and the demand side of the industry. In the Ontario electricity market, this would include ensuring we have the efficient supply mix, both at the transmission and distribution level given our demand profile, and that consumers are making the right investments in the technologies needed to manage their consumption.[4]

- ***Consumer Benefits*:** Consumers are responsible for most if not all of the costs of the electricity system. Changes to power markets are sometimes evaluated based on the impact the changes will have on the cost to consumers.

  With utilization payments, DR resources would have an incentive to bid values lower than the ceiling price into the energy market as they would receive payment whenever they are activated. This may lead to reduced wholesale energy prices if DR resources are bidding lower than traditional generation. The merit of utilization payments may be evaluated based on their ability to reduce cost to consumers.

- ***Level of Participation or Activation:*** Another consideration that is relevant for DR is the level of participation or the level of activation. The level of participation refers to the amount of DR, typically measured in megawatts, that is registered or contracted. In certain circumstances, the level of participation can be used as a proxy for the level of competition. The level of activation

[4] Charles River Associates. *How to put Ontario's power market on a faster track to economic efficiency*. October 2016.

refers to the amount of DR that is activated, typically measured in megawatt-hours, over a defined period.

With utilization payments, more DR resources may participate in the market. If more resources are participating in the market the competition is likely to be greater which would like to lower costs. The merit of utilization payments may be evaluated based on their ability to increase the amount of DR participating in the market.

- ***Fairness:*** Another potential consideration is fairness or consistency. In the context of DR, fairness typically refers to how traditional generation resources are compensated relative to demand-side resources.

  DR resources are bidding into the market alongside generation. In the case that they are dispatched rather than generators one could argue that they should be compensated in the same way as the generators.

- ***Materiality:*** A final consideration is materiality. The materiality of the impact of changes to payment structures and payment levels can be a consideration.

  When examining the merit of introducing utilization payments any potential impacts should also be examined by evaluating how significant their impacts. For example, introducing utilization payments may increase participation in the market but this impact may not be significant enough to make any impact on consumer costs.

As a point of consideration, in FERC Order No. 745, the commission ultimately determined that fairness/consistency and materiality outweighed economic efficiency[5].

[5] See Appendix for more detail on FERC 745

3. ECONOMIC EFFICIENCY ARGUMENTS

This section presents the arguments for and against providing utilization payments to DR resources.

3.1 Against Activation Payments in Ontario

3.1.1 Wholesale Price Efficiency

The argument is as follows. Real-time wholesale energy prices are an efficient price signal because they match supply and demand based on bids and offers on a minute-by-minute, hour-by-hour basis.

When price responsive loads are exposed to real-time wholesale electricity prices they assess whether it is more cost effective for them to operate or curtail based on the real-time price signal. During high-price events a customer can choose to curtail and save the cost of electricity. This provides an economically efficient incentive to reduce consumption when prices are higher than a customer is willing to pay.

For example, large industrial customers such as pulp and paper pay for electricity based on the wholesale electricity price. These customers can determine on an on-going basis if it is more economically efficient for them to continue operating and producing pulp and paper given the required input costs of electricity than it would be to stop production leading to loss of production revenues but savings in electricity costs.

<u>Considerations for Ontario:</u> This argument only applies to loads that receive the wholesale energy price. Many large commercial and industrial customers in Ontario are already exposed to wholesale energy prices. These customers are already price responsive. They can determine based on real-time energy prices if it is more cost effective from them to operate or to curtail. These customers would not need an additional payment to be incented to curtail when they are needed by the system. There are some customers in Ontario who are not exposed to the wholesale electricity price. These customers are not exposed to price spikes that occur in the wholesale electricity prices. Since they aren't exposed to the price spikes they are not receiving the signal to curtail when needed by the system. The wholesale price efficiency argument is not relevant in those cases. In Ontario, 58% of the total load is exposed to the market price[6].

3.1.2 Disproportional Benefits

The argument is as follows. Providing a utilization payment compensates a DR resource disproportionally relative to a supply resource, because the DR resource did not incur a cost associated with the production of electricity. Under this argument, a DR resource should be treated as if it had first purchased the power it wishes to resell to the market.

This argument is based on a premise that a megawatt of electricity curtailed (negawatt) is not economically equivalent to producing a megawatt of electricity. This was the argument put forward by a group of economists in support of the Electric Power Supply Association's petition to US Court of Appeals

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[6] http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20170817-presentation.pdf?la=en

to overturn FERC Order No. 745.[7] This argument was supported by FERC Commissioner Philip D. Moeller, who argued that paying demand response resources full LMP overcompensates those resources because in addition to any incentive payments received, those resources also receive the benefit of not paying the cost of retail energy consumption that they otherwise would have incurred[8].

The underlying factor of this argument is the claim that DR is not a resource in the same way that generation is. A generating resource is providing a product and is paid for that. Opponents of DR utilization payments argue that since DR does not own the power they are not consuming, they should not be paid additionally for not consuming it. Despite this argument, FERC's final 745 ruling[9] was based on the premise that negawatts and megawatts are functionally and economically equivalent.

Considerations for Ontario: This argument is based on a premise that a megawatt of electricity curtailed (negawatt) is not equivalent to a megawatt of electricity. The argument assumes the cost of curtailment (or the value of lost load) for a DR resource is immaterial. Whether the disproportional benefits argument is considered valid in Ontario depends on whether this premise accepted.

3.1.3 Harm to Other Suppliers

The argument is as follows. Utilization payments can lead to greater levels of activation that put downward pressure on wholesale energy prices and negatively impact the profitability of other supply resources.

While initially a benefit to consumers, the argument is that this practice has the potential to harm suppliers in the long term to a point where existing or new generators, required to maintain system reliability, are not able to operate economically. This argument is based on the concept of dynamic efficiency.

The argument is that if more DR resources bid into the market at prices lower than traditional generation they will be dispatched rather than the generation. This is because the more demand response that sees and responds to higher market prices, the greater the competition, and the more downward pressure it places on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high. This may make it difficult for the generators to recover their costs and ultimately to continue operating. In practice, the impact of providing a utilization payment has not been significant enough to affect generators ability to recover their costs.

Some FERC 745 commenters assert that a power system can function solely and reliably on generating plants and without any reliance on demand response, while the system cannot rely exclusively on demand response because demand response by itself cannot keep the lights on[10].

Considerations for Ontario: To have a material impact on energy prices, utilization payments would have to result in a considerable increase in activation. Also, under the current market structure in Ontario, most generators are under contract or receive regulated rates and hence have a high degree of revenue or price certainty.

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[7] https://sites.hks.harvard.edu/fs/whogan/Economists%20amicus%20brief_061312.pdf

[8] https://www.cleanenergylawreport.com/energy-regulatory/federal-appeals-court-vacates-ferc-order-no-745-on-demand-response-compensation/

[9] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

[10] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

3.1.4 Harm to Economy

The argument is as follows. Providing utilization payments may incentivize companies to reduce production to provide demand reductions into the electricity market. Reducing production would in turn reduce the supply of goods in the economy that could increase the cost of these goods.

This argument comes back to the concept of allocative efficiency. It relies on the argument that the wholesale energy price signal is efficient and that introducing a utilization payment will result in inefficient outcomes.

For example, if a company which is producing widgets is incentivized through utilization payments to curtail their load and stop producing widgets fewer widgets will be available to buy. This reduced supply may increase the price of the widgets in the market. In practice, the impact of providing a utilization payment is not expected to be significant enough to cause a material impact on supply of goods (widgets) in the market.

Considerations for Ontario: This argument only valid for supply constrained and non-trade exposed sectors of the economy where prices are set based on local supply and demand. Ontario has a diversified and open economy that responds effectively to changes in supply.

For Activation Payments in Ontario

3.1.5 More DR Activation Reduces Consumer Costs

The argument is as follows. Utilization payments will increase levels of DR participation and activation in lieu of more expensive generation resources.

Utilization payments are a way to incentivize higher levels of DR participation and activation. These DR resources will provide less expensive capacity and energy that in turn will lead to lower consumer costs. This argument is based on the concept of productive efficiency.

For example, if a utilization payment incents DR resources to bid into the energy market at lower prices they will likely be activated more often. If the DR resources are bidding lower than the traditional generation resources the wholesale energy price will be lower. These reduced prices will be passed through to customers in the form of reduced consumer electricity costs.

Large commercial and industrial customers with a high value of lost load are not likely to change their bids into the energy market because of utilization payments however smaller commercial or residential customers who may have a lower value of lost load are likely to bid into the energy market below the ceiling price. While this will lower energy prices, the impact is not expected to be significant since these resources do not represent a significant amount of the supply required in Ontario.

Considerations for Ontario: To have a material impact on capacity or energy prices, utilization payments would have to result in a considerable increase in levels of participation and activation. Under the current market structure in Ontario, most generators are under contract or receive regulated rates and hence consumer costs are largely fixed. It is also possible that reduced electricity costs could lead to reduced manufacturing costs that may be passed along to consumers as reduced cost of goods.

3.1.6 Disconnect Between Wholesale and Retail Prices

The argument is as follows. There is a disconnect between retail energy prices and wholesale energy prices. Retail prices don't reflect the real-time fluctuations in the cost of electricity and hence are inefficient. DR resources that are exposed to retail prices behave inefficiently because they are not exposed to the true cost of electricity on a short-term basis. Utilization payments are a way of improving the economic efficiency of the retail price during high-price events.

Retail rates paid by some consumers are fixed in advance and do not fluctuate during peak periods. Even when the market price (and the cost) of generating an additional megawatt of electricity during a peak period is relatively high, retail customers (who typically have unlimited access to supply at a fixed rate) do not curtail demand in response to the price signal. For that reason, many economists agree that it may be useful to provide retail consumers with an incentive to avoid using electricity, i.e., to stimulate DR during peak periods.[11] The economically efficient goal should be for resources to reduce their consumption whenever the value of their consumption is lower than the cost of supplying it. It should be noted that many of the existing DR resources in Ontario are exposed to real-time wholesale prices. Emerging DR resources such as aggregated residential or commercial loads are exposed to retail prices as opposed to wholesale prices. As a result, these resources would benefit from a price signal that would incent them to curtail in response to wholesale prices.

<u>Considerations for Ontario:</u> This argument is only valid for customers on retail rates who are not exposed to real-time energy prices. As described previously, many providers of DR in Ontario are already exposed to wholesale rates.

3.1.7 Fairness/Consistency

The argument is as follows. Generation resources receive a utilization payment in the form of an energy payment when they produce electricity. DR resources should be treated fairly/consistently and receive a utilization payment when they curtail electricity.

The argument takes the position that a DR resource and a generation resource providing a megawatt of electricity for the same period are equivalent and should be compensated equivalently. The principle behind this argument is that both demand and supply are "electricity resources". DR has demonstrated that it can serve as a reliable and economic resource for wholesale markets and integrated resource plans. It has demonstrated its ability to mitigate market power that can arise in a generation-only market.

This argument was supported by FERC in the FERC 745 ruling[12]. The Commission argued that when a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and when dispatching and paying LMP to that demand response resource is shown to be cost-effective as determined by the net benefits, payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable. When these conditions are met, we find that payment of LMP to these resources will result in just and reasonable rates for ratepayers. FERC indicated that they believe paying demand response resources the LMP will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO.

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[11] https://sites.hks.harvard.edu/fs/whogan/Economists%20amicus%20brief_061312.pdf

[12] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

The Public Service Electric & Gas Company (PSE&G) argues that a MW of demand response does not make the same contribution towards system reliability as a MW of generation, because demand response committed as a capacity resource is only required to perform for a limited number of times over the peak period.

Considerations for Ontario: This argument is the counter-point to the disproportionate benefits argument. Whether the equivalence of the product provided by DR and generating resources is accepted is a main point of contention on utilization payments.

3.1.8 Other Costs Associated with Curtailment

The argument is as follows. For dispatchable loads, electricity is as much an input as an output. The cost of producing a megawatt of electricity for a load is equal to the value of lost load, which can be higher than the price cap imposed in most organized wholesale energy markets (in Ontario the price cap is CAD $2,000 per megawatt-hour).

Another way to think about this argument is that, for a load, the cost of producing electricity in the form of curtailment is equivalent to the lost revenue and additional costs incurred (i.e. lost profit) associated with a reduction in production. DR resources have both fixed costs such the initial investment in technology such as monitoring and controls software to manage and execute DR operational activities and variable costs, such as labor cost and loss of productivity during the DR activation period. This value may vary significantly by DR resource. In jurisdictions where utilization payments are provided, activation levels for DR in the energy market are still relatively low. This suggests that even when provided with a utilization payment, the lost profit or value of lost load may still be much higher.

Considerations for Ontario: For large commercial and industrial customers, the value of lost load (VOLL) can be very high, which could result in limited activation of DR resources regardless of whether utilization payments are offered. Residential customers generally have a lower VOLL ($0/MWh - $17,976/MWh) than commercial and industrial customers (whose VOLLs range from about $3,000/MWH to $53,907/MWh)[13]. Given the sensitivity of VOLL to a variety of specific factors such as customer's consumption profile, a region's macroeconomic and climatic attributes, as well as the types of outage these ranges these ranges may be different for Ontario.

3.2 Considerations for Ontario

The arguments for and against utilization payments are nuanced and prudent. Responsible stakeholders can arrive at different conclusions based on preferences for evaluation criteria.

A unique consideration for Ontario is that today, almost all generation resources are compensated under long-term contract or through regulation that guarantees a certain level of revenue. The economic efficiency arguments under this current market structure are different than they would be if considering the future state of the wholesale power market where generation resources are largely compensated through energy and capacity market revenues. Under the current conditions, more DR activation (as a

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[13] http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

result of bidding into the market at prices lower than traditional generators) would not actually lead to reduced costs to consumers since generators have their compensation guaranteed. In the future when if DR resources compete against generation assets in the capacity market, traditional generators may lose revenue because of being under bid by DR. This would result in reduced (though likely not significant) costs to consumers.

4. WIDER MARKET IMPACTS

Introducing utilization payments for DR can have both direct and indirect impacts on the Ontario electricity system. It is important to consider both types of impacts, particularly in the context of the proposed changes associated with Market Renewal.[14] This section describes the impact on a qualitative basis. Additional effort is required to estimate the quantum of the impacts.

The key question is whether the current Ontario framework of only offering availability payments is sufficient. Considering this:

- Would there be more or different types of DR offered into the market?
- What are the impacts on energy market prices and costs?
- How much and to what extent are other market participants and consumers impacted?

When considering the wider market impacts it is important to keep in mind that if utilization payments do not significantly change the activation levels of DR than the impact on the energy price will be negligible and the additional utilization payments will be minimal.

4.1 Direct Impacts

<u>DR resources change their bids into the energy market and are activated more often</u>
With utilization payments, DR resources would have an incentive to bid values lower than the ceiling price into the energy market as they would receive payment whenever they are activated. Each participating resource would have to determine the value of consuming electricity relative to their avoided cost plus the utilization payment and use that to define their bid into the market. The magnitude of this impact depends on the mix of participating DR resources. Experience in other markets has shown that the impact is likely to be small for traditional DR providers but as technologies change, expanded capabilities and changing business models may result in larger impacts on bidding strategies.

Consider DR aggregators who collect multiple residential or small commercial loads (typically air conditioning) to bid into the energy market. These DR resources have a low value of lost load. If a utilization payment were provided they are likely to bid into the energy market more frequently and at lower prices to get activated more often and get additional revenues.

<u>DR participation increases in both the capacity and energy markets</u>
With the additional incentive of utilization payments, there may be increases in the amount of DR that enters the Ontario system. The magnitude of this impact depends on whether there is a material increase in revenue for traditional DR or if there are viable new business models that can rely on the changed incentives.

Some resource types such as aggregated residential or small commercial loads may have a higher initial cost of DR (such as an incentive cost per customer) but a low value of lost load. If a utilization payment were provided the economics for this type of customer would be more attractive. That would lead to more DR resources offering into the capacity market and more DR resources bidding into the energy market at lower prices. Currently aggregated residential and small commercial load only represents a small amount of DR participation so this is not expected to have a large impact on participation or activations.

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[14] Market impacts have to be evaluated in the context of a specific payment structure so the impacts in this section assume that utilization payments are tied to LMP even though there are other utilization payment structures that could be considered.

However, additional technology improvements are leading to more load being available to aggregators for DR participation.

4.2 Indirect Impacts

Energy prices, particularly during price spikes, decrease

If the utilization of DR resources increases, there will be downward pressure on energy prices. The impact depends on whether DR resources change their bids to be below the ceiling price or if there is significant new entry of DR resources due to the changed incentives. If neither of these conditions is true, then the impact on energy prices will be minimal.

As noted above, the introduction of utilization payments may attract more DR resources with higher initial investment but lower value of loss load. This type of resource (e.g. residential AC) is more likely to bid into the energy market at lower prices which would lead to the DR resource being dispatched rather than a more expensive traditional generator. The overall impact would be decreased energy prices though again the impact is not expected to be significant since large C&I customers who represent a significant amount of DR resources typically have a high value of lost load and are not expected to change their bids into the energy market.

Capacity prices change

If DR participation in the market increases and it can meet capacity obligations, then there could be reduced need for other capacity resources. This would put downward pressure on capacity prices. However, reduced energy prices increase the net revenue requirement of traditional resources and they would likely increase their offers into the capacity market which could put upward pressure on capacity prices. The relative impacts of these two dynamics is difficult to estimate.

Considering again aggregated residential or small commercial loads; adding these additional offers into the capacity market will lead to greater competition. Competition generally leads to lower prices however it is possible that traditional generation participating in the capacity auction would need to increase their capacity offers if they anticipated being activated less often and receiving lower revenues through the energy market.

DR resources receive higher revenues

With an additional source of revenue, DR resources would likely receive higher overall revenues. For current market participants, even if they do not change offering/bidding strategies, they would add utilization payments when prices reach the ceiling and they are dispatched. The caveat to the higher revenues is whether there is a reduction in availability prices that offsets the utilization payments.

DR resource with a high value of lost load are unlikely to receive higher revenues. For these resources (typically large C&I customers) it would not be economically efficient for them to change their bids in the energy market even if a utilization payment were provided. For DR resources with lower value of lost load revenues are expected to increase. These resources would bid into the energy market more frequently leading to additional revenues collected through utilization payments.

Improved flexibility

With the additional incentive of utilization payments, there may be increases in the amount of DR that participates in the wholesale market in Ontario. This will lead to additional quick response resources being available to balance the electricity grid which will support system reliability and address resource adequacy.

Activating DR resources rather than traditional supply resources reduce the load on the electricity distribution system which can increase the life of the system equipment and may lead to deferral of capacity projects. They also represent an emissions free resource which leads to additional environmental benefits when these resources are activated rather than traditional supply generators.

<u>System costs change</u>

Each of the indirect dynamics discussed above change the overall system cost. Incremental activation payments to DR providers would increase costs. Decreases in capacity and energy prices would decrease costs. It is challenging to estimate the relative magnitude of the impacts.

If utilization payments are added to the system, but the mix and level of DR participation and activation remains the same, then the overall impact of the change would be minimal. However, if the change resulted in a large increase in participation and activation then the incentives could be a material reduction in system costs.

As described above, if additional residential and small commercial customers participate in the DR auction and then bid into the energy market more often at lower prices they will be activated more often and at a lower price than traditional generators. This will lead to lower overall system costs.

However, if all resources who participate in the DR auction continue to be large C&I customers with value of lost load higher than the energy ceiling price, DR resources will likely continue to bid into the energy market at the market ceiling price and will not be activated any more than they are now. Under this scenario, no changes in system costs would be expected.

<u>Production Losses</u>

With the additional source of revenue some DR resources may be incented to bid into the energy market at lower prices leading to more frequent curtailment. This could lead to declines in the domestic production of other goods, which in turn could change the price of these goods in the economy. These impacts are expected to be minimal, as jurisdictions that added or increased utilization payments did not realize a significant increase in the activation levels of DR.

As described above, if a company which is producing widgets is incentivized through utilization payments to curtail their load and stop producing widgets fewer widgets will be available to buy. This reduced supply may increase the price of the widgets in the market. In practice, the impact of providing a utilization payment is not expected to be significant enough to cause a material impact on supply of goods (widgets) in the market.

5. SUMMARY OF DR PARTICIPATION IN OTHER JURISDICTIONS

5.1 Jurisdictions with Relevant DR Programs

DR is a common resource in organized wholesale power markets. Navigant reviewed markets that have a history of DR, ideally within a power market framework. Navigant reviewed the products in each jurisdiction that are most applicable to Ontario. These include both economic/energy DR and reliability/capacity DR.

In many jurisdictions, the same DR resource can participate in both an economic/energy and reliability/capacity programs at the same time, which allows them to collect both availability and utilization payments. DR can participate in ancillary service markets in many jurisdictions, however, the requirements for these markets are very specific and the use of utilization payments in these markets is widely accepted. For this reason, ancillary services DR is not discussed within this section but is covered in Appendix A, where additional cross-jurisdictional details are provided.

The jurisdictions reviewed were selected to cover diverse geography, payment structures, and payment levels. Navigant reviewed publicly available documentation for all jurisdictions to understand the DR resource requirements and payment structures. Interviews were also conducted with contacts at the PJM, CAISO, ERCOT, AEMO (Australia) and with an expert on the DR auction in South Korea.

Most markets in the US are FERC jurisdictions and because of the recent FERC ruling have a requirement to provide utilization payments. As a result, Navigant and the IESO identified a need to examine jurisdictions outside of North America as well. Within the US, PJM was selected since it represented the most established market for DR participation in power markets. California was selected to cover innovative ways of incorporating DR into power markets through the DRAM mechanism. New York was selected as a less mature jurisdiction which also included the types of DR being examined (economic and reliability). ERCOT was selected as a non-FERC US jurisdiction which represents alternative compensation mechanisms to FERC jurisdictions. Outside of North America, Navigant and the IESO worked to identify regions with applicable DR programs (economic and reliability) that are relatively well established. This led to the identification of Finland (which is a relatively well establish region for DR participation in the power markets), France (which is also a well-established DR market and has recently introduced a capacity certificate program), Australia (which has recently gone through a review process for potential introduction of a DR mechanism that would allow aggregators to bid DR into power markets) and South Korea (which has very recently added DR participation to the power markets).

Seven of the eight jurisdictions examined have economic DR. Five of the eight jurisdictions have reliability DR.

5.2 Payment Structures and Levels

5.2.1 Economic DR

Navigant examined the features of economic DR across all jurisdictions. The economic DR products are like the IESO's existing DR market structure, in that they bid directly into the wholesale energy market and are dispatched using the ISOs' security constrained dispatch algorithm. They differ from the IESO's existing DR market structure in that they receive utilization payments for the provision of economic/energy DR. Economic DR resources do not receive capacity payments in exchange for bidding into the energy market.

The jurisdictions reviewed include FERC jurisdictions (California, NYISO and PJM) and non-FERC jurisdictions (France, Finland, Australia, South Korea). ERCOT does not have an exclusively economic/energy DR product. In 2011, the FERC in the US ruled that DR resources bidding into the Day-Ahead and Real-Time energy markets should be paid the full locational marginal price (LMP) like other generation resources bidding into the markets. This set a requirement for California, NYISO and PJM to provide utilization payments equivalent to LMP.

All three jurisdictions opposed FERC Order No. 745 and have suggested that LMP minus generation is a more appropriate payment level. Australia, France, Finland and South Korea are non-FERC jurisdictions. These jurisdictions provide a utilization payment equal to the wholesale energy price. For the two jurisdictions where Navigant completed interviews (Australia and South Korea) this incentive level was reported to have been selected based on consistency, since the DR resources are participating in the energy market like other supply resources.

Some key features of the payment structures and levels for energy/economic DR are noted below.

1. In all jurisdictions reviewed resources that provide economic/energy DR receive utilization payments.
2. In jurisdictions that also procure reliability/capacity DR, resources can participate in both (and receive availability payments for providing reliability DR and utilization payments for providing economic DR).
3. Participation and activation levels vary considerably by jurisdiction.
    - In NYISO no resources have bid into the energy market even though the program is available to do so. This may indicate that the cost to curtail is higher than the ceiling price.
4. Some jurisdictions have a floor price for DR bidding into the wholesale energy market. FERC Order No. 745 set a net benefit price requirement that represents the price at which the benefits incurred by a reduction in wholesale prices from the economic DR will exceed the cost to pay for the economic DR. The net benefit price is set as the minimum price at which DR can bid into the market.
5. The magnitude of the utilization payment has been debated across regions (e.g. wholesale market clearing price vs. wholesale market clearing price minus cost of generation).

Jurisdiction	Name of Service	Notification Time	Utilization Payment Levels	Participation
California	Proxy DR	Day Ahead (by 3pm) or Real Time	Wholesale market clearing price	160[15] MW
NYISO	Day-Ahead DR Program (DADRP)	Day-ahead and 2-hours prior	Wholesale market clearing price	0 MW (No bidding activity since 2010)
Mid Atlantic US (PJM)	Economic DR	30 minutes	Wholesale market clearing price	2,096 MW in 2017 (decreasing or stagnant)
France	NEBEF Energy Wholesale	Day ahead or Real Time	Wholesale market clearing price	600-1000 MW[16]

[15] https://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf
[16] http://www.smartenergydemand.eu/wp-content/uploads/2015/09/Mapping-Demand-Response-in-Europe-Today-2015.pdf

Jurisdiction	Name of Service	Notification Time	Utilization Payment Levels	Participation
Finland	Elspot & Elbas	Day ahead or Intraday	Wholesale market clearing price	200-600 MW Day-Ahead; 0-200 MW Intraday
South Korea	Load Curtailment	Day Ahead	System Marginal Price	Unknown
Australia	Economic DR	Day Ahead	Wholesale market clearing price	Unknown

5.2.2 Reliability DR

Five of the eight jurisdictions examined have reliability DR programs. These programs are like the IESO DR market structure from the perspective that they provide an availability payment in exchange for the ability to use DR in a reliability event. In some jurisdictions, reliability resources also receive utilization payments when activated. They are also able to participate in economic DR programs that can lead to higher levels of activiation for which they are further compensated with additional utilization payments. They differ from the IESO DR market structure in that these resources are not also required to bid into the energy market. They are dispatched administratively by the ISOs.

In addition to the five jurisdictions with reliability DR that is integrated into power markets, France has a capacity mechanism that acts as a decentralized market which does not interface with the energy market. Generators and suppliers trade capacity certificates. Capacity certificates come with a right to the corresponding energy. DR resources are eligible to participate in the capacity mechanism. By trading capacity certificates, DR resources would be able to collect a payment that would be analogous to an availability payment. No additional energy payments are received.

DR resources in PJM, NYISO, and South Korea are all able to participate in both economic/energy and reliability/capacity programs. They are provided an availability payment through the capacity/reliability program in exchange for being available to be dispatched during a reliability event. They are also paid a utilization payment when dispatched by clearing the energy market or when dispatched administratively by the ISO through reliability DR.

California recently introduced a Demand Response Auction Mechanism (DRAM), which is a pay-as-bid auction of monthly local, system, and flexible capacity for third party offerors. Bidding in the DRAM is done by the utilities rather than customers themselves. Each utility has a target of DR capacity that they are required to acquire.

Some key features of the payment structures and levels for reliability/capacity DR are noted below.

1. Resources that are participating in the reliability DR programs receive availability payments for being available in a reliability event.
2. Resources are dispatched administratively, they are not typically dispatched by the ISOs' security constrained economic dispatch algorithm.
3. When activated, reliability DR resources are paid a utilization payment in 4 of the 5 jurisdictions.
4. Resources can participate in both reliability/capacity and economic/energy DR programs. In theory, this enables higher levels of activation, as DR resources are dispatched when economic and for reliability reasons. Both reliability and economic dispatch are compensated by utilization payments.

5. For NYISO and PJM, participation in the reliability DR programs is significantly higher than participation in the economic DR programs.[17] This suggests that wholesale prices are not high enough for many customers to be incented to reduce demand and that the availability payment is a larger driver.

Jurisdiction	Name of Service	Notification Time	Payment Type & Level	Participation
California	DRAM	Day Ahead (by 3pm) or Real Time	Availability & Utilization (Wholesale price)	200 MW under contract for 2018/19[18]
NYISO	Installed Capacity – Special Case Resource (ICAP-SCR)	2 hour and Day Ahead	Availability & Utilization (Wholesale price)	1,192 MW 2016[19]
Mid Atlantic US (PJM)	Limited, Extended Summer, Annual, Base DR	30 min	Availability & Utilization (Wholesale price)	9,123 MW 2016[20]
Texas - ERCOT	ERS or Load Resources	10 min or 30 min	Availability Payment	896 MW (Oct 17-Jan 18)[21]
South Korea	Capacity DR	1 hour	Availability & Utilization (Wholesale price)	3,885 MW 2016[22]

5.3 Motives and Outcomes

DR is playing an expanding role in electricity systems in many jurisdictions. Participation levels vary across jurisdictions and have been impacted by the magnitude of the availability and utilization payments available. Anecdotally, jurisdictions with higher wholesale prices have experienced higher levels of DR activation.

In the jurisdictions reviewed by Navigant, only utilization payments are made to DR resources for economic/energy DR. Availability payments and utilization payments are made to reliability/capacity DR resources.

PJM, NYISO, and CAISO are all FERC jurisdictions and are required to follow FERC Order No. 745. Under this order, FERC requires ISOs to compensate DR when activated with utilization payments equal

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17 This may also be true for South Korea, however, the economic DR participation is not available publicly.

18 Program is still in pilot phase

19 http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/Demand_Response/Reports_to_FERC/2017/NYISO%202016%20Annual%20Report%20on%20Demand%20Response%20Programs_Final.pdf

20 https://pjm.com/~/media/markets-ops/dsr/2017-demand-response-activity-report.ashx

21 http://mis.ercot.com/misapp/GetReports.do?reportTypeId=11465&reportTitle=ERS%20Procurement%20Results&showHTMLView=&mimicKey

22 South Korea has recently moved from a contract model to market based participation. Not clear how much of the DR is actually being activated in the energy market.

to LMP. Proponents of this ruling argued that DR resources should be paid like other supply resources, since they are providing a similar product and the gains seen through bill reductions only cover a portion of the variable costs incurred by the DR resources when curtailed. Many of the ISOs in the US argued that paying the full LMP was overcompensating DR. The ISOs recommended compensating the DR provider as if it had first purchased the power it wishes to resell to the market.[23]

PJM indicated during an interview with Navigant that it does not support the full LMP utilization payment, because it is an implicit subsidy. They noted that the introduction of LMP utilization payments lead to higher activation levels, though not significantly, leading to an immaterial impact financially. Long term, PJM wants to revisit the payment structure. ERCOT, which does not have to follow FERC Order No. 745, elected to not provide utilization payments since DR resource customers are receiving the wholesale energy price signal.

Following the FERC ruling, jurisdictions experienced higher, though not significantly, DR activation levels. Following FERC Order No. 745, PJM reported:

- an increase in energy market participation;
- an increase in the amount of energy market activity in the day-ahead market; and
- better performance (actual delivered load reductions closer to amount dispatched in real-time market or cleared in day-ahead market).

PJM indicated the potential for a significant increase in economic DR activity, since most DR resources who are registered have not submitted offers into the real-time or day-ahead market and the majority of emergency DR resources do not participate as an economic DR resource. The average megawatts settled after FERC Order No. 745, relative to immediately before, grew (approximately 20 MW to over 60 MW). However, the utilization factor for DR in the energy market is still only a very small fraction (~3 percent) of the overall DR capability. Only a small percentage of the DR which is registered is activated through the energy/economic DR. This suggests that wholesale prices are not high enough for most customers to be incented to reduce demand.[24]

[23] http://www.caiso.com/Documents/FinalSupplementalOpiniononEconomicIssuesRaisedbyFERCOrder745.pdf

[24] http://pjm.com/-/media/markets-ops/dsr/20150701-order-745-impact-on-economic-dr.ashx?la=en

APPENDIX A. ADDITIONAL JURISDICTIONAL SCAN DETAILS

Navigant reviewed publicly available documentation for each of the jurisdictions selected to determine:

1. What types of DR (economic/energy, capacity/reliability, etc.) does each jurisdiction procure from loads.
2. The structure (market-based, program-driven, etc.) used to remunerate loads for providing these services. In particular, to determine whether DR resources are offered utilization payments in addition to (or instead of) availability payments.
3. Where utilization payments *are* offered, how those payments are made, e.g., a fixed payment per event, LMP-based, etc.

Navigant was also able to complete interviews with contacts from 5 jurisdictions (PJM, CAISO, ERCOT, Australia and South Korea) to discuss the motivations behind providing the incentive types they offer.

The table below provides a summary of the jurisdictional scan findings and is followed by a detailed description of each jurisdiction.

Table 1: DR Jurisdictional Scan Summary

Jurisdiction	Type of DR	Name of Service	Notification Time	Payment Type	Bid into wholesale markets?
California	Emergency	Optional Binding Mandatory Curtailment Program	15 min	Contract payment	No
	Economic	Proxy DR	Day Ahead (by 3pm) or Real Time	Utilization payment	Real Time and Day Ahead
	Capacity	System/Flexible/Local DR	Day ahead or Real Time	Capacity & Utilization payment	DRAM auction
New York (NY-ISO)	Emergency	Emergency DR Program (EDRP), Installed Capacity – Special Case Resource (ICAP-SCR)	2 hour and Day Ahead	Contract payment	No
	Economic	Day-Ahead DR Program (DADRP)	Day ahead or Real Time	Utilization payment	Day ahead or Real Time
	Ancillary	Demand Side Ancillary Services Program (DSASP)	Fully Automated, 4 s, 10 min	Spot price for service	Ancillary services market
Mid Atlantic US (PJM)	Emergency	Limited, Extended Summer, Annual, Base DR	30 min	Availability Payments & Energy Payments	Real time and Day Ahead
	Economic	Economic DR	Day ahead or Real Time	Utilization Payment	Real time energy markets

Jurisdiction	Type of DR	Name of Service	Notification Time	Payment Type	Bid into wholesale markets?
	Ancillary	Synchronized reserve, Frequency regulation	10 min or 30 min	Spot price for service	Ancillary services market
Texas (ERCOT)	Emergency	Emergency Response Service	10 min or 30 min	Availability Payments	No
	Capacity	Load Resource	5 min	Availability Payments	Real time energy markets
	Ancillary	Responsive Reserve	Fully automated, 4 s or 10 min depending on service	Spot price for service	Ancillary services market
France	Economic	NEBEF Energy Wholesale	Day ahead or Real Time	Utilization (spot price) payments	Day Ahead and Intraday
	Balancing, Ancillary Services and Reserves	Balancing, Ancillary Services and Reserves	<30 s, < 400 s, 13 min, 30 min depending on service	Availability & Utilization payments	Ancillary service markets
	Capacity	Capacity Mechanism	Day Ahead	Decentralized market which does not interfere with the energy market	No
Finland	Economic	Elspot & Elbas	Day ahead or Real Time	Utilization Payments	Day ahead or intraday
	Ancillary	FCR-N, FCR-D, FRR-A, Balancing Power market	Automatic, 5 s, 30 s, 2 min, 15 min based on service provided	Availability & Utilization Payments	Ancillary service markets
Australia	Ancillary	Ancillary services	6 s, 1 min, and 5 min depending on product	Spot price for service	Ancillary services market

Jurisdiction	Type of DR	Name of Service	Notification Time	Payment Type	Bid into wholesale markets?
South Korea	Economic	Load Curtailment	Day Ahead	Utilization Payment (System Marginal Price)	Real time and day ahead market
	Capacity	Capacity DR	1 hour	Availability & Utilization Payments	No

A.1 New York (NYISO)

DR programs in NYISO can be broadly classified into two categories, reliability DR and economic DR. Participants in NYISO can participate in one reliability and one economic DR program in parallel. Participation in both programs in parallel is most closely aligned to the IESO DR auction. When participating in both, participants receive an availability payment (through the reliability program) and bid into the wholesale energy market (through the economic program). Some key differences should be noted: (1) participants can be activated administratively (because of a reliability event) through the reliability program (2) participants receive a utilization payment when activated through either the reliability or economic programs.

Reliability Based Programs*:* During periods of increased demand, or when the grid is affected by unplanned events such as inclement weather, the NYISO's market pays participants in these programs for load reductions that lessen stress on the electric grid. Program rules unique to the ICAP-SCR program also enable participants to receive monthly payments (called "capacity payments") based on the obligated level of load reduction (i.e., the committed level of load reduction at the facility when the NYISO requests that participants reduce load). There are two reliability based program available:

- Installed Capacity – Special Case Resource (ICAP-SCR) program
- Emergency DR Program (EDRP) program

Economic Based programs*:* These programs provide participants the opportunity to offer load reduction into New York's electricity markets in response to high electricity prices. Day-Ahead DR Program (DADRP) participants submit to the NYISO an "energy offer" to reduce consumption at the price the participants determine. Similarly, Demand Side Ancillary Services Program (DSASP) participants submit "reserves" and/or "regulation" service offers to the NYISO. If the offer is accepted and scheduled by the NYISO, DSASP participants are eligible to receive market payments based upon actual performance.

Table 2: NYISO Capacity and Energy Market Summary

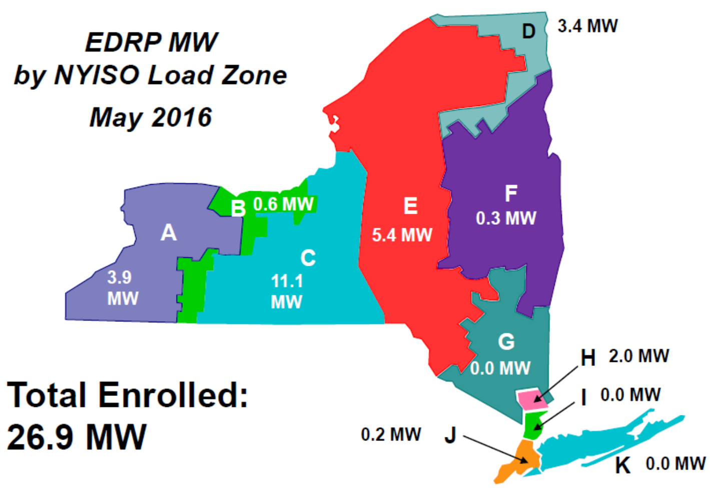
Category	Capacity Market	Energy Market
Program Period	Annual (can bid seasonally or monthly)	Annual (bid at will)
Event Windows	Anytime	Based on bidding and clearing
Dispatch Limits	4 hours	Based on bidding and clearing
Notification Time	Day-ahead and 2-hours prior	Day-Ahead or Real-Time, based on bidding and clearing
Curtailment Limits	None	Based on bidding and clearing
Tests	1 per season (Summer and Winter)	N/A
Enrollment Deadlines	Monthly	Daily bidding
Payments	Monthly	Monthly
Minimum Size	100 kW	1 MW

Category	Capacity Market	Energy Market
Metering Requirements	1 hour	1 hour
Baselines	Average Coincident Load (highest 20 hours of load in the system 40 peak hours)	Customer Baseline: High 5 of 10 days

Source: Navigant Research and NYISO website

The ***Installed Capacity (ICAP) Special Case Resources (SCR) program*** provides financial incentives for electricity consumers larger than 100 kW to reduce their electricity use or operate on-site generation during periods of electricity reserve shortage. NYISO provides 2-hour notice of curtailment events as well as day-ahead advisories. Participants receive two separate payment streams: a capacity payment based on their committed load reduction and energy payments for their actual load reductions during curtailment events. Participants face non-compliance penalties if they do not curtail their committed amount when called by NYISO. Individual customers must participate through an authorized Responsible Interface Party (RIP) who coordinates transactions with NYISO, and cannot commit the same resources in both the Emergency DR program and the SCR program.

Figure 1: Summer 2016 EDRP Enrollment



Source: NYISO's Semi-Annual Report to FERC (June 1, 2016)

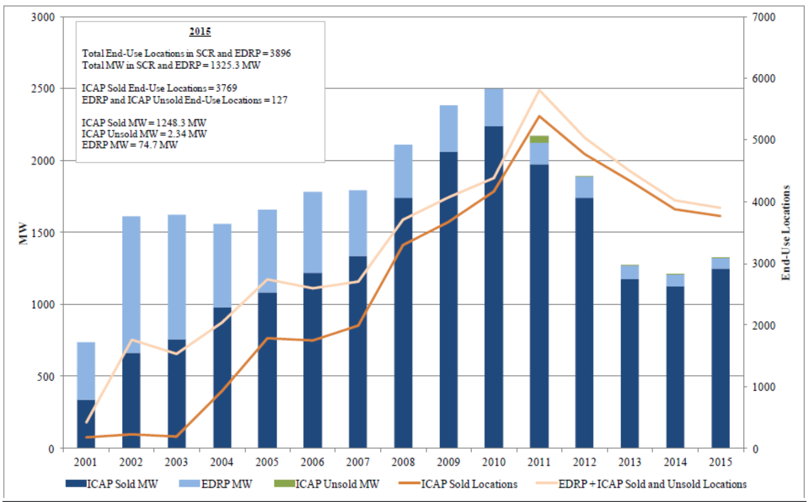
Payment: Monthly Capacity payments are based on sales made through ICAP auctions or bilateral contracts. The energy payments are based on performance in events & tests; Locational Based Marginal Pricing (LBMP) with daily guarantee of strike price recovery.

The ***Emergency DR Program (EDRP)*** provides financial incentives for electricity users to voluntarily reduce consumption and/or operate on-site generation during periods of electricity reserve shortage in New York. NYISO typically provides 2-hour notice of curtailment events as well as day-ahead advisories (although in some cases immediate deployment is requested). Participants receive the higher of \$500/MWh or the real-time zonal Locational Based Marginal Price (LBMP) for their curtailments.

Participation in any curtailment event is voluntary, and there are no penalties for non-performance. Individual customers can either participate directly in EDRP (if their load reduction is at least 100 kW) or through an authorized curtailment service provider (CSP), such as a utility, energy service company, or curtailment customer aggregator. Customers cannot participate in both the Emergency DR Program and the Installed Capacity Special Case Resources (SCR) program (see above). EDRP and SCR are dispatched separately by NYISO, with SCR resources dispatched first, and EDRP customers called only if additional resources are needed.

Payment: The energy payments are based on measured energy reduction during an event, with a minimum rate of $500/MWh or the actual LBMP, if higher.

Figure 2: Historical Program Growth SCR and EDRP



Source: NYISO's Semi-Annual Report to FERC (January 12, 2016)

Table 3: NYISO EDRP & SCR Events and Payments

Summer	#Resources and Registered MW	Events	Avg Hourly Response	Energy Payments	Avg. payment per MWh
2009	4,067 2,384 MW	No events	N/A	N/A	N/A
2010	4,386 2,498 MW	31 hours downstate 19 hours TDRP, plus 12 ICAP/SCR & EDRP	1.85 MW (TDRP) 178.1 MW (ICAP/SCR & EDRP Energy)	$1.09 million	$500
2011	5,807 2,173 MW	11 hours downstate 5 hours Upstate	7/21/11: 414 MW 7/22/11: 1065.2 MW	$3.8 million	$500

Summer	#Resources and Registered MW	Events	Avg Hourly Response	Energy Payments	Avg. payment per MWh
2012	5,032 1,888 MW	39 hours Downstate including 9 hours TDRP, 30 hours ICAP/SCR & EDRP, 20 hours Upstate ICAP/SCR & EDRP	3.6 MW (TDRP) 1196 MW (June 21 Statewide ICAP/SCR & EDRP)	$5.9 million	$514
2013	4,495 1,270 MW	27 hours Downstate 10 hours Upstate	915.2 MW (July 19 Statewide ICAP/SCR & EDRP)	$6.9 million	$524
2014	3,704 900 MW	6 hours Statewide	236.2 MW (Jan 7 ICAP/SCR & EDRP)	$346,356	$509
2015	3,896 1,325 MW	No events	N/A	N/A	N/A

Source: NYISO website

The ***Day Ahead DR Program (DADRP)*** provides electricity users with the opportunity to bid load reductions into New York's day-ahead wholesale electricity market, where their bids compete with generators' offers to meet the state's electricity demand. At their discretion, customers can submit load reduction bids on a day-ahead basis by indicating the load reduction amount, price (between $50 and $1,000 per MWh), and time period. If the customer's bid is accepted and the customer fully curtails, they receive payment for their accepted bid, based on the greater of the bid price or the day-ahead LBMP.

If the customer fails to fully curtail, they will pay the higher of the day-ahead price (LBMP) or the real-time price for the amount of incomplete scheduled load reduction. Individual customers can either participate directly in DADRP if their load reduction is at least 1 MW, or through an authorized curtailment service provider, such as a utility, energy service company, or a curtailment customer aggregator. Most of these providers require a customer to be able to reduce load by at least 100 kW in each hour. Unlike in the EDRP and SCR programs, standby generators are not eligible for participation. Day-ahead participants can also be registered in EDRP.

DADRP enrollment has been static for several years and enrolled resources have not submitted demand reduction offers for more than four years. DADRP enrollment remained unchanged since the January 2016 Report.

Payment: The incentive payment is the product of Day-Ahead LBMP (wholesale market clearing price) and the lesser of actual or Day-Ahead scheduled load reduction. The curtailment initiation can be paid on a daily basis, if applicable. Some program providers allow customers to bid both a price for each hour's load reduction bid and an additional amount, called the curtailment initiation cost (CIC). The CIC places a floor on the total payment received if the bid is accepted.

NYISO also offers a ***Demand-Side Ancillary Services Program (DSASP)***, through which loads can provide 10- and 30-minute non-spinning operating reserves. To participate, registered demand-side resources submit availability bids to the day-ahead market. If these bids are accepted, the demand-side customer is paid the market clearing price for that level of reserves (e.g., 10- or 30-minute). In return, the customer must comply with load reduction signals from NYISO. If the resource is asked to actually reduce demand in real time, it will also be paid the real-time market price for energy. If the customer changes its operating reserve offer in real time, the difference between this and the day-ahead reserve amount is financially settled at the real-time operating reserve price. A demand-side resource cannot offer the same capacity in the DADRP and DSASP on the same day.

For DSASP, participants have to get modeled in the NYISO system model and the undergo testing before being allowed to participate. Historical participation is low, around 150 MW.

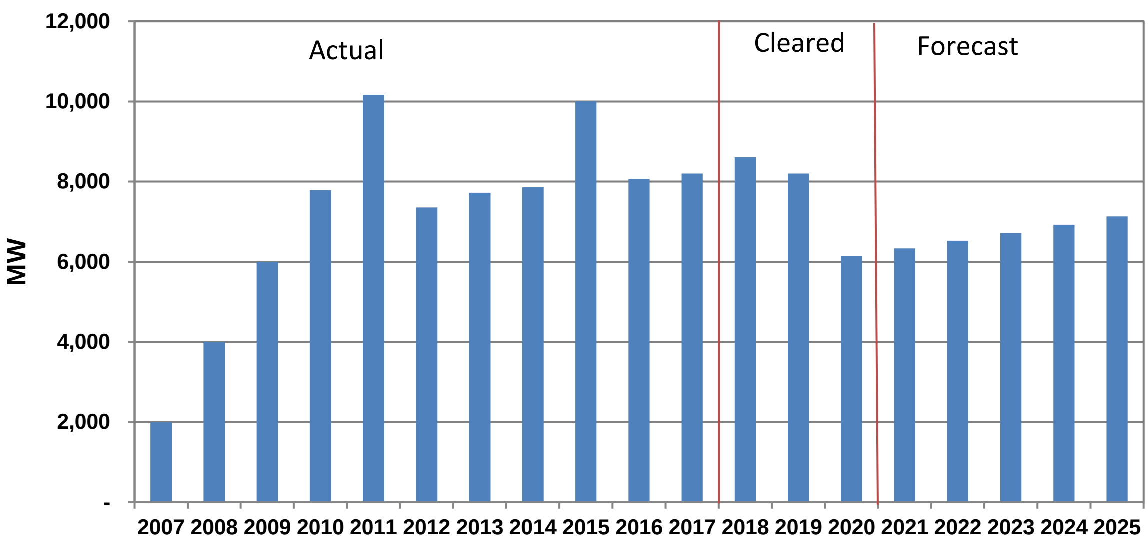
Payment: Resources are paid marginal clearing prices for Ancillary Service product scheduled. This price is based on auction clearing price which is dependent on location and the product.

A.2 PJM

PJM's DR opportunities enable retail electricity consumers to earn a revenue stream for reducing electricity consumption when either wholesale prices are high or the reliability of the electric grid is threatened. DR participation is broken in two broad classifications, economic and emergency. An electricity consumer may participate in either or both depending on the circumstances. In the PJM region, DR has accounted for as much ~10% of the total.

Similar to NY, resources in PJM territory can participate in both the economic and emergency programs in parallel. The emergency program provides an availability payment and if activated (either administratively through the emergency program or based on wholesale price in the economic program) they receive a utilization payment.

Figure 3: PJM Historical and Projected DR volume



Source: PJM data and Navigant estimates

Pre-Emergency and Emergency DR primarily represents a mandatory commitment (referred to as Load Management Resources AND Demand Resources (DR)) to reduce load or only consume electricity up to a certain level when PJM needs assistance to maintain reliability under supply shortage or expected emergency operations conditions. This is considered a mandatory commitment to which penalties are applied for noncompliance. The Curtailment service provider's (CSP) resources must be available to respond to PJM's request to reduce load where the availability depends on the product selected by the CSP as follows:

- ***Limited DR*** (only available through 17/18 Delivery Year) – resource is available for up to 10 weekdays from June through September, where each request may be up to six hours in duration.
- ***Extended Summer DR*** (only available through 17/18 Delivery Year) – resources are available for all days from May through October, where each request may be up to ten hours in duration
- ***Annual DR*** – resources is available for all days from June through May of following year, where each request may be up to 15 hours in duration
- ***Base DR*** (only available for 18/19 and 19/20 Delivery Years) – resource is available for all days from June through September, where each request may be up to ten hours in duration

Table 4: PJM Capacity Market DR

Category	Current	Capacity Performance
Program Period	Summer (June-September)	Annual
Event Windows	12-8 PM	May-Oct: 10 am-10 pm; Nov-Apr: 6 am-9 pm
Dispatch Limits	6 hours per event	None
Notification Time	30 minutes	30 minutes
Curtailment Limits	10 events	None
Tests	1 per year	1 per year
Enrollment Deadlines	May each year	May each year
Payments	Monthly	Monthly
Minimum Size	100 kW	100 kW
Metering Requirements	1-hour interval meter	1-hour interval meter
Baselines	Firm Service Level using Peak Load Contribution	Firm Service Level using Peak Load Contribution (Summer and Winter)

Source: PJM Website and Navigant Research

As of 2017, PJM will only procure Annual Capacity performance products. PJM considers these resources like a generator and fully expects them to perform at the time when the grid most needs it to avoid brownouts and/or rolling blackouts within the PJM service territory. The CSP is responsible for managing their portfolio of customers to meet their obligations and avoid creating an operational problem on the grid and/or receiving financial penalties.

The revenue stream derived from participation is largely driven by the "Capacity" market as defined under the Reliability Pricing Model (RPM). The revenue earned is a function of the relevant price and the load reduction commitment. The resource is paid to be "available" during expected emergency conditions on a monthly basis for a commitment that is made for one year, which starts on June 1 and ends on May 31 of the following year.

Emergency DR (Load Management) Event Penalties are assessed by curtailment service providers and distributed, as a bonus, to resources that perform above expectations, based on the ratio of the relevant resource's bonus performance level to the total bonus performance from all resources over the same Performance Assessment Hour.

Economic DR primarily represents a voluntary commitment to reduce load in the energy market when the wholesale price is higher than the published monthly PJM net benefits price. The net benefit price represents the price at which the benefits incurred by a reduction in wholesale prices from the economic DR will exceed the cost to pay for the economic DR. The economic DR will be used to displace a generation resource and PJM expect the resource to perform and will assess deviation charges if the amount of load reductions realized is significantly different than the amount of load reductions dispatched by PJM.

An economic DR resource may also provide **Ancillary Services** to the wholesale market with the appropriate infrastructure and qualification by PJM. There are three Ancillary Services markets in which economic DR resources may participate: Synchronized Reserves (the ability to reduce electricity consumption within 10 minutes of PJM dispatch), Day-Ahead Scheduling Reserves (the ability to reduce electricity consumption within 30 minutes of PJM dispatch) and Regulation (the ability to follow PJM's regulation and frequency response signal). Participation in the market is voluntary; however, if a resource clears, performance is mandatory. PJM fully expects the CSP to perform to maintain system reliability. Currently, there are several electricity customers that provide synchronized reserves into the wholesale market.

Table 5: PJM Energy Market DR

Category	Description
Program Period	Annual (bid at will)
Event Windows	Based on bidding and clearing
Dispatch Limits	Based on bidding and clearing
Notification Time	Day-Ahead or Real-Time, based on bidding and clearing
Curtailment Limits	Based on bidding and clearing
Tests	N/A
Enrollment Deadlines	Daily bidding
Payments	Monthly

Category	Description
Minimum Size	100 kW
Metering Requirements	1 hour
Baselines	Customer Baseline: High 4 of 5 days

Sources: Navigant Research

A.3 California (CAISO)

California is going through a period of transition in their DR market. Utilities run DR programs in California[25] through bilateral contracts with customers and DR aggregators and DR Auction Mechanism (DRAM). In the future, DR will be allowed to participate directly in CAISO markets. The DRAM in California or the Proxy DR is most closely aligned with the DR auction in Ontario since this program will involve bidding DR resources directly into the market. However, in the DRAM, the bidding will be done by the utilities rather than the customers themselves. Each utility has a target of DR capacity that they are required to acquire. Since CAISO is a FERC jurisdiction, customers are paid full LMP based on energy bid into the market.

As part of an effort to replace utility DR programs into demand- and supply-side resources and then integrate DR resources into the California Independent System Operator's (CAISO) markets by 2018, the California PUC established a ***DR Auction Mechanism (DRAM)*** pilot for third parties to provide DR outside of utility programs. During the pilot, the IOUs and third parties offer portions of their own DR portfolios into the CAISO market.

It is a pay-as-bid auction of monthly local, system, and flexible capacity for Offerors to bid directly in the California Independent Operator System ("CAISO") market. Offerors must bid directly into the CAISO energy market and any resulting revenues or liabilities allocated solely to the Offeror.

- ***System Capacity***: IOU-wide, can be bid into CAISO market. Must bid per CAISO must-offer obligation in day ahead and/or real-time market.

- ***Local Capacity***: Must be located in Local Capacity Areas (LCAs). For SCE, covers the LA Basin and Big Creek/Ventura Substations; for PGE, Local Capacity Product must be within one of PG&E's seven LCAs; SDG&E, entire service area. Same must-offer obligation (MOO) as System.

- ***Flexible Capacity***: Bids in to Day Ahead and Real Time Energy market, able to ramp and sustain energy output for a minimum of three hours, must be a PDR resource. Addresses variability and unpredictability created by intermittent resources. Must bid per CAISO must-offer obligation for flexible resources.

Offeror's DR resource shall be comprised of a Proxy Demand Resources ("PDR") or Reliability DR Resource ("RDRR") or multiple PDRs and RDRRS that aggregate customers.

Proxy DR (PDR) resources can be bid economically in the day-ahead and real-time markets as supply. The total amount of proxy DR that was awarded in the day-ahead market decreased by almost half in

[25] https://energy.gov/eere/femp/energy-incentive-programs-california

2016 from the previous year. Day-ahead market awards for proxy DR were most significant in June, July and September on several days with particularly high day-ahead forecasts and peak system loads.

The total amount of proxy DR capacity registered in 2016 decreased to about 160 MW from almost 200 MW during 2015. Only a fraction of this capacity was bid into the market. Between June and December, scheduling coordinators bid in a combined average of about 10 MWh of proxy DR capacity for about 4 hours during peak weekday periods.

The current Commission DR requirements to qualify for local and flexible Resource Agency mandate the DR resource to bid into the CAISO energy market under the CAISO Must-Offer Obligation (MOO) for DR as one or more PDR(s) or RDRR(s) as defined in the CAISO Tariff.

Many utility programs also provide DR opportunities:

The ***Automated DR (Auto-DR) program*** provides free technical assistance and incentives to customers of PG&E, SCE, and SDG&E for installing automated DR equipment.

Participation is open to customers enrolled in a qualifying DR or time-varying pricing programs (PG&E's Peak Day Pricing or SCE and SDG&E's Critical Peak Pricing program). Auto-DR uses communication and control technology to automatically implement the customer's chosen pre-programmed load reductions, providing a fast and reliable way to respond to peak events, while still leaving the customer in complete control.

Incentives range from $125 to $400/kW of reduction capability, depending on level of automation and utility. Eligible equipment includes energy management systems and software, wired and wireless controls for lighting, HVAC, thermostats, motors, pumps and other equipment capable of receiving curtailment signals. SCE also offers the Auto-DR Express program to smaller customers (up to 400 kW peak demand).

The Base Interruptible Program (BIP) offered by PG&E, SCE, and SDG&E pays participants to reduce electric load to (or below) a level pre-selected by the customer (called the firm service level or FSL) that is below its historic average maximum demand. Customers receive a monthly incentive payment or credit based on the size of the curtailable portion of their load, in return for committing to reduce to the FSL when called upon by the utility with thirty minutes' notice. The incentives typically range from $7 to $9 per committed kW per month, even if no events are called. There is a minimum curtailment commitment of 100 kW, or 15% of the monthly average peak demand (whichever is larger). PG&E and SDG&E also offer a longer, 3-hour, notice in exchange for a lower incentive option ($3/kW), and SCE offers a shorter, 15-minute notice option for a higher incentive. Requests for curtailments (which can last up to four hours) cannot exceed one per day, ten per month, or 120 hours per year (90 hours for the lower incentive options). Penalties apply for customers that fail to reduce load as requested—the amount depends on the utility and the incentive option.

All three utilities have contracted with numerous third-party aggregators who recruit customers to participate in BIP and manage their participation process. By serving as an intermediary, the aggregators can handle many of the details on customer's behalf and help them develop load reduction strategies. The aggregators may also offer innovative program features – for example, by assuming the risk of non-compliance penalties or by allowing customers to participate who might otherwise be too small to enroll directly in the utility's program. BIP participants are also be eligible for simultaneously participating in one of the other DR programs, (e.g., time-varying pricing or PG&E/SCE's Demand Bidding Program), which allows customers to take advantage of rate credits, reduced energy charges and incentives associated with both programs, with some restrictions.

Under the ***Capacity Bidding Program*** (CBP), PG&E, SCE, and SDG&E participants receive a monthly incentive for pledging to reduce their energy use to a pre-determined amount in the event a CBP event is called by the utility, which can occur weekdays from May through October, 11 a.m. to 7 p.m. The program offers either a day-ahead or day-of notification option. Customers receive the monthly payment (varies by utility, time of year and notification option) whether an event is called. Failure to reduce the pledged amount during an event will result in reduced incentives and possible penalties for not meeting at least 50% of the pledge. Customers typically enroll in CBP through a third-party aggregator, who manages their participation and relays their monthly reduction pledge, which can vary. Participants can opt for day-ahead notification, or receive higher incentive levels by choosing "day of" event notification. PG&E CBP participants may also be eligible to concurrently participate in additional PG&E DR programs.

Critical Peak Pricing (CPP) from SCE and SDG&E (also called the Summer Advantage Incentive) is a rate structure that offers lower electricity rates year-round in return for setting a higher rate on specific summer afternoons. The rate is three to five times higher than the regular rate on up to fifteen "critical peak" afternoons during the summer with customers notified of CPP days on a day-ahead basis. It is also the default rate for large commercial and industrial customers of SCE. For new program entrants, a bill protection option is available that prevents participants from paying more than they would have under their previous rate during the first year of CPP participation. Participants may also opt for technical assistance to help them better take advantage of the program. SDG&E customers participating in the Day-Ahead option of the Capacity Bidding Program are not eligible for CPP.

Peak Day Pricing (PDP), very similar to SCE's and SDG&E's Critical Peak Pricing (see above), is the default rate for PG&E's large commercial, industrial and agricultural customers. Small and medium business customers (demand 200 kW and less) will automatically transition to PDP beginning November, 2014. PDP is a "time varying" pricing plan with additional charges added during critical peak times (2-6 p.m. on 9 to 15 "Peak Event Days" per year, with some alternative durations available). Participants shield their exposure to high prices during PDP events by shedding load during the peak price hours. Customers on E-19 and E-20 rate schedules (demand of 500-999 kW and 1000+ kW respectively) have the option to mitigate bill fluctuation by allotting a portion of their load to a "capacity reservation."

The ***Demand Bidding Program (DBP)*** offered by PG&E and SCE provides incentive payments of up to $0.50/kWh for curtailment commitments. Participants place bids online the day before a peak event for the amount of power they are willing to reduce (minimum 10 kW each hour), in increments of two hours or more. DBP events usually take place from noon to 8:00 p.m. and can occur on any weekday excluding holidays. There is no penalty for failure to reduce electric load during an event.

PG&E and SCE offer the ***Optional Binding Mandatory Curtailment Program***, which provides customers with exemptions from rotating power outages if they can reduce their circuit load during Stage 3 emergencies. Participants must reduce their power consumption by 15% below their established baseline load for the duration of every rotating outage event. The penalty for failure to reduce as requested is $6.00 per kWh for energy use that exceeds an established baseline.

SCE's ***Summer Discount Plan and SDG&E's Summer Saver program*** offer summer air conditioner cycling programs to commercial customers These programs provide a credit on participants' summer season electric bills in return for allowing the utility to cycle air conditioners when needed during the months of May to September. Customers can choose among several options regarding the frequency and duration of curtailments, each with corresponding remuneration levels.

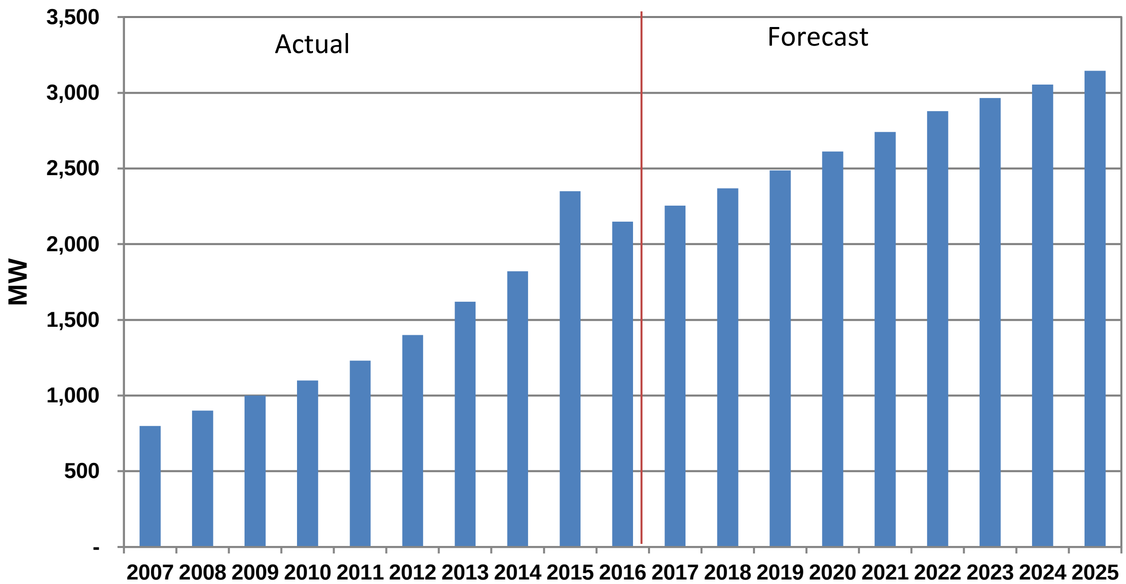
SCE offers the ***Scheduled Load Reduction Program (SLRP)*** to qualified bundled-service customers whose average monthly demand is 100 kW or more. The program provides a $0.10 per kWh on-bill credit for reducing load on prescheduled days and times on weekdays from June 1 through September 30.

PG&E and SCE offer financial incentives for implementing technologies that permanently shift electric load by storing thermal cooling capacity during off-peak hours (e.g., by chilling water or making ice) in order to meet cooling load during subsequent peak hours.

A.4 Texas (ERCOT)

Federal customers can receive payments for providing load curtailments through several programs offered by the Electric Reliability Council of Texas (ERCOT). DR participation in ERCOT territory can be split broadly into economic and emergency DR. Through the economic DR program, customers bid DR into the energy market and are paid a utilization payment. Since ERCOT is not a FERC jurisdiction they are not required to pay the full LMP. ERCOT provides payment of LMP-G for DR resources which are cleared in the energy market. These resources are not paid an availability payment for participation in the energy market but may also participate in one of the emergency DR programs through which they would receive availability payments.

Figure 4: ERCOT Historical and Projected DR volume



Source: ERCOT and Navigant. Combination of LR and ERS programs

Table 6: ERS & Energy Market DR summary ERCOT

Category	ERS	Energy Market DR
Program Period	Annual, broken into three 4-month offer periods	Annual (bid at will)
Event Windows	Broken into 6 weekly and daily bidding windows	Based on bidding and clearing
Dispatch Limits	None	Based on bidding and clearing

Notification Time	Can choose 10 or 30 minutes	Real-Time: Resources with bids at marginal LMP must be capable of moving load incrementally in either direction every five minutes, based on dispatch instructions
Curtailment Limits	12 hours per 4-month contract period	Based on bidding and clearing
Tests	1 per year	N/A
Enrollment Deadlines	30 days prior to start of contract period	Daily bidding
Payments	Monthly	Monthly
Minimum Size	100 kW	1 MW
Metering Requirements	15-minute interval meter	15-minute interval meter
Baselines	Choose between several options: Regression, High 8 of 10, Matching Day, Weather-Sensitive	Compare telemetered load to basepoint instructions

Sources: Navigant Research

Load Resource Participation[26] : Customers who can change their load in response to an instruction and can meet certain performance requirements may qualify to become Load Resources (LRs). Qualified LRs may participate in ERCOT's real-time energy market (Security-Constrained Economic Dispatch, or SCED) and/or may provide operating reserves in the ERCOT ancillary services (AS) markets. In the ERCOT markets, the value of a Load Resource's load reduction is equal to that of an increase in generation by a generating plant. Load Resources in SCED submit bids to buy power "up to" their specified level, and are instructed by ERCOT to reduce Load if wholesale market prices equal or exceed that level. Load Resources that are scheduled or selected in the ERCOT Day-Ahead AS Markets are eligible to receive a capacity payment regardless of whether they are curtailed.

Voluntary Load Response: A customer may decide independently to reduce consumption from its scheduled or anticipated level in response to price signals or high demand on the ERCOT system. This is known as Voluntary Load Response[27].
Depending on how the retail contract with their Load Serving Entity (LSE) is structured, these customers may have the opportunity to benefit financially during periods when wholesale market prices are high.

[26] http://www.ercot.com/services/programs/load/laar
[27] http://www.ercot.com/services/programs/load/vlrp

Emergency Response Service (ERS): As with the Load Resource program, customers bid to provide load reductions. However, this program is aimed solely at alleviating emergency (as opposed to high price) conditions on the ERCOT grid. ERCOT procures ERS three times annually for four-month Standard Contract Terms (SCT). In each SCT, ERCOT procures ERS per two different response times—thirty minutes and ten minutes[28].

For all programs, the customer participates through its Retail Electricity Provider (REP), and transactions with ERCOT are conducted by the qualified scheduling entity (QSE) for the customer's REP. The specific terms for customer participation, including compensation, are based on the contractual arrangement between the customer and their REP.

Table 7: DR Participation in ERCOT ERS

Year	MW
2017	890
2018	935
2019	982
2020	1,031
2021	1,082

Sources: ERCOT website; DR forecasts are Navigant estimates

A.5 France

France has a mature market which allows DR to participate in all markets (day-ahead, intraday, balancing, ancillary services, reserves and capacity). This has been achieved by allowing aggregators to operate independently of suppliers. Prequalification of all products participating in the markets is completed by the TSO to validate the capacity. These prequalification test are designed by the RTE and are different for each product depending on the service required. The NEBEF Mechanism is most closely aligned to the IESO DR auction since it involves bidding DR into the wholesale market. Participation in the NEBEF mechanism provides only utilization payments (no availability payments). DR resources are paid the spot price when they are activated. Participation was high in 2016 due to high wholesale prices.

NEBEF Mechanism (Day-Ahead and Intraday markets)*:* The NEBEF mechanism allows DR to bid directly into the wholesale market as energy. This mechanism has been in place since 2013 for the day-ahead and January 2017 for the Intraday markets. The volume of DR activated through the Day-Ahead market was low to begin (310 MWh in 2014), partially due to a mild winter. Since then the participation has been 1.522 GWh (2015) and 10.313 GWh (2016)[29]. Offers through the NEBEF mechanism were intensive at the end of 2016 due to high wholesale prices. To participate in the NEBEF mechanism, the DR provider is required to sign a contract with the TSO. The minimum size of DR bids must be 0.1 MW. Activation of DR through the wholesale market is managed by the TSO based on the system requirements. The DR is bid directly into the EPEX Spot market and DR are paid the spot price when they are activated.

[28] http://www.ercot.com/services/programs/load/eils

[29] http://www.smartenergydemand.eu/wp-content/uploads/2017/04/SEDC-Explicit-Demand-Response-in-Europe-Mapping-the-Markets-2017.pdf

Balancing, Ancillary Services and Reserves: Two ancillary service markets (The Frequency Containment Reserve (FCR) and the Automatic Frequency Restoration Reserves (aFRR)) are open to DR participation. Historically, bids into the ancillary service markets and balancing programs needed to include only DR or only generation. Beginning in January 2017, aggregated DR and generation was allowed to bid experimentally into the FCR. Contracts for FCR and aFRR total 600-700 MW capacity each. Both the FCR and aFRR have minimum bid sizes of 1 MW, are activated automatically, receive very short notification times (<400 s) and can be triggered an unlimited number of times. FCR and aFRR are paid availability payments based on their contracts and when activated are paid the spot price in the market. In cases where the DR is not available, penalties are based on the spot price rather than the availability payments.

Two Balancing Mechanism markets manual Frequency Restoration Reserve (mFRR) and Replacement Reserves (RR) are open to DR participation in France. A maximum of 1000 MW is contracted for mFRR and a maximum of 500 MW is contracted for RR. The participation in 2016 was 480 MW. The mFRR and RR have minimum bid sizes of 10 MW, are activated manually, receive short notification times (<30 min) and can be triggered an unlimited number of times. The TSO activates bids based on the most economic offer. DR therefore competes against generation. The mFRR and RR are paid both an availability payment and when activated an energy payment based on their bid. In cases where the DR is not available, penalties are based on the spot price rather than the availability payments.

Capacity Mechanism*:* The capacity mechanism was launched in January of 2017 in response to growing concerns about security of supply[30]. The capacity mechanism is a decentralized market which does not interfere with the energy market. Capacity certificates are traded apart from the energy market and owning a capacity certificate does not give any rights to the corresponding energy. All capacity owners in France have an obligation to commit on their availability during peak periods 3 years in advance. All suppliers must own capacity certificates which correspond to the consumption of their customers during the peak periods. In its first year, the capacity market included 1700 MW of certified exchangeable capacities and 800 MW of capacity obligation reduction from retailers. The capacity will reflect only the availability of DR in the market. Its effective activation will be counted through the balancing mechanism or wholesale market[29].

A.6 Finland

In Finland, DR can participate in all markets (day-ahead, intraday, balancing, ancillary services, reserves and capacity) however Finland is able to source a significant amount of their capacity needs from neighboring countries which may be limiting actual DR participation in the markets. Participation in the Economic DR is most closely aligned to the IESO DR auction. DR resources are paid only a utilization payment (spot price) for participating. No availability payments are provided.

Economic DR (Day-Ahead and Intraday Markets)*:* Operating on the Elspot (day-ahead) and Elbas (intraday) markets requires an agreement with Nord Pool, as well as an agreement with an open electricity provider, which also covers balance responsibility. Historic participation in the day-ahead market has been between 200-600 MW and participation in the intraday market has been between 0-200 MW. The day-ahead and intraday markets both require a minimum demand resource size of 0.1 MW to participate. DR participating in the wholesale markets is paid the spot price for energy. In the wholesale

[30] http://www.ceem-dauphine.org/assets/dropbox/DGEC-_Etienne_Hubert.pdf

markets, penalties are based on the imbalance settlement price which corresponds to the Nordic balancing market price.

Ancillary and Balancing Services*:* Finland allows participation of DR in all ancillary services through Fingrid. A summary of the services, contract types, minimum size requirements, activation time and payments is provided below[31].

Summer	#Resources and Registered MW	Events	Avg. Hourly Response	Energy Payments	Avg. payment per MWh	Payment Type
Frequency controlled normal operation reserve (FCR-N)	Yearly and hourly markets	0.1 MW	1 MW	Automatic - 3 minutes	Constantly	Yearly market + Price of electricity
Frequency controlled disturbance reserve (FCR-D)	Yearly and hourly markets	1 MW	240 MW	Automatic 5 s / 50% 30 s / 100%, when f under 49,9 Hz OR 30 s, when f under 49,7 Hz and 5 s, when f under 49,5 Hz	Several times per day	Yearly Market
Frequency controlled disturbance reserve (on-off-model) (FCR-D)	Long-term contract	10 MW	240 MW	Automatic Instantly, when f under 49,5 Hz	About once a year	Availability + Activation Fee
Automatic Frequency Restoration Reserves (FRR-A)	Hourly market	5 MW	0 MW	Automatic Must begin within 30 s of the signal's reception, must be fully activated in 2 minutes	Several times a day	Hourly market + energy price
Balancing power market	Hourly market	10 MW	100-300 MW	15 minutes	According to the bids, several times per day	Market price

[31] http://www.fingrid.fi/en/electricity-market/Demand-Side_Management/Market_places/Pages/default.aspx

Summer	#Resources and Registered MW	Events	Avg. Hourly Response	Energy Payments	Avg. payment per MWh	Payment Type
Fast disturbance reserve	Long-term contract	10 MW		15 minutes	About once a year	Availability + Activation Fee

A.7 Australia

Australia has enabled DR participation in the wholesale market however third parties (aggregators) are not allowed to bid in. When participating in the wholesale market, resources are paid a utilization payment only (electricity spot price). Participation directly in the wholesale market has not been very high however retailers who cover the majority of the electricity consumption use DR as a tool to manage their costs.

The energy market has already developed innovative solutions to facilitate consumers' DR, reflecting the absence of any barriers to demand side participation. Retailers have at least 235 MW of DR capacity under contract, and demand side management providers are managing at least 310 MW of DR capacity. Other estimates suggest 2000 MW of DR capacity that is available to respond to wholesale market prices.[32]

DR Mechanism (DRM)*:* Australia investigated implementing a DRM which would unbundle the provision of energy from the provision of ancillary services. The proposal was to allow DR to be settled through the wholesale market by third parties however the mechanism was determined to be unnecessary in the market today. The review determined that the benefits of the regulatory mechanism can be achieved under existing conditions. Market and technology developments mean that large customers, retailers, DSM providers and businesses can already negotiate commercial arrangements with one another leading to a competitive DR market.

Ancillary Services*:* As of July 2017, DR will have access to ancillary services markets. Currently the following Ancillary service products are available: Regulating, Fast, Slow, Delayed[33]. *Payment:* Ancillary services are procured daily at the spot price on the Ancillary services market.

The Ancillary Services Unbundling changes will enable third parties to register and sell Frequency Control Ancillary Service (FCAS) using aggregated loads independently of the retailer. This means that at the commencement of the DRM, the DRAs will be able to offer DR as FCAS if it satisfies the NEM's technical requirements. The existing technical and procedure requirements will apply to the DRAs.
Any load offered by a DRA as ancillary service cannot simultaneously be offered as DRM load for a DR interval and the DRM process has no involvement in the settlement of that DRA or load in providing FCAS.

When required, Australia goes through a tender process to acquire DR as a capacity resource. Resources provide bids which include three payments, an availability fee, a pre-activation fee and an energy payment. If selected the resources are paid the availability fee and then if activated are paid the pre-activation and energy payment.

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32 http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism/Draft/AEMC-Documents/Draft-Determination.aspx

33 http://www.brattle.com/system/publications/pdfs/000/005/220/original/AEMC_Report.pdf?1448478639

A.8 South Korea

In April 2014, legislation was passed in South Korea allowing DR to participate in its wholesale capacity market. DR resources which previously were under contract bid into the DR auction when it opened in 2014. These resources receive availability payments. They then bid into the energy market and receive the system marginal price for energy when activated.

South Korea has a system peak of about 80GW, more than 80% of which is from commercial and industrial energy users. With electricity consumption growing at a rapid rate and a reliance on fuel imports to meet nearly 100% of its needs, South Korea is actively promoting DR to help ensure reliability, encourage competition, and develop an ecosystem of IT-based energy businesses. The enablement of DR is one of the requirements of South Korea's 'Creative Economy' initiative, which in the energy sector is broadly revolved around measures to deal with domestic energy demands and to respond to global climate change[34].

Table 8: DR Summary South Korea

Category	Capacity DR	Energy DR
Program Period	Bidding (Twice / year)	Day Ahead bidding
Notification Time	1 hour ahead	Day Ahead
Payment	Capacity* + Variable cost of Marginal Gen	SMP** (System Marginal Price)

**Capacity payment in first 6 months of 2017: 19,894.7 won/kw*
***Average SMP in first 6 months of 2017: 84.36 won/kwh*
Source: Interview with Korea Electrotechnology research institute

The DR (DR) market was introduced in the Korean electricity market in November 2014. In the past, demand management was implemented through the program by Korea Electric Power Corporation (KEPCO) in Korea. However, after the DR market was opened, a third party called "the load aggregator" was allowed to participate in the Korean electricity market. Load aggregators have recruited the resources of KEPCO's customers who have participated in demand management.
DR resources (DRR) have been traded in the Korean wholesale electricity market since November 2014. Customers can join the DR market only through a load aggregator. There are 17 load aggregators registered in the electricity market as of June 2017. In the DRR market, peak curtailment DRRs (or capacity DRRs) and price responsive DRRs are traded separately.

In the case of ***capacity DRRs (peak curtailment)***, Korea Power Exchange (KPX) (Independent System Operator in Korea Electricity Market) instructs a load curtailment an hour ahead, and these resources assume a role to substitute for high-cost generators. The customers participating in the load curtailment are compensated with incentives such as ***payments for availability and performance***[35].

The payment for availability is calculated in the same method as the capacity price of generators and the payment for performance is determined based on the resources' actual curtailment and the highest variable generation cost at that time.

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[34] https://www.engerati.com/article/demand-response-comes-south-korea

[35] DR Resource Allocation Method Using Mean-Variance Portfolio Theory for Load Aggregators in the Korean DR Market; Jaeyong Chae and Sung-Kwan Joo; June 2017

In the case of ***Energy DRR (price responsive)***, the resources bid on the day-ahead electricity market and curtail the load if the demand reduction price is lower than the bid prices of generators, and are compensated with incentives based on the system marginal price (SMP).

At this point DR does not seem to participate in the Ancillary services market in South Korea[36].
The Korea Power Exchange (KPX), the transmission grid operator for South Korea, implemented its Smart DR program several years ago. This program was an all-automated DR approach for commercial and industrial (C&I) customers. KPX also pursued 500 MW of wholesale market DR participation with its Smart DR initiative. It achieved this through capacity auctions and other market-based mechanisms similar to the constructs in the U.S. RTO markets (e.g., PJM and ISO-NE). These programs were funded by the government, separate from the competitive electricity market.

The DR program starts with seasonal procurements of DR resources. DR may bid into the day-ahead energy market within the committed load reduction, and then it is obliged to reduce up to the committed load reduction when KPX orders a load reduction in real-time. The KPX DR program is intended to encourage DR aggregators to participate in the market, and utilities such as the Korea Electric Power Corporation are not allowed to participate.

[36] http://www.globalsmartgridfederation.org/wp-content/uploads/2016/12/flexibilitylow.pdf

APPENDIX B. FERC 745 RULING

The details of the FERC 745 ruling are included in this appendix. Under the law, FERC has jurisdiction over wholesale electricity markets, which reach across state lines, but states have legal authority over their individual retail markets. The Electric Power Supply Association (EPSA), the national trade association for competitive power suppliers, argued that Order 745 crossed over too much into these retail markets, constituting an overreach of federal authority[37]. The Supreme Court disagreed with EPSA. In a 6-2 decision with Justice Samuel Alito recusing himself, the nation's highest judicial body ruled that FERC acted within its powers enumerated under the Federal Power Act (FPA) in issuing the order, which aims to ensure that DR providers are compensated at the same rates as generation owners. Many of the ISOs and econometricians oppose the ruling.

B.1 Federal Regulatory Energy Commission ("The Commission") Final Rule

In their original ruling[38], FERC argued that providing LMP as compensation to demand response resources helps to ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates.

The Commission argued that when a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and when dispatching and paying LMP to that demand response resource is shown to be cost-effective as determined by the net benefits, payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable. When these conditions are met, we find that payment of LMP to these resources will result in just and reasonable rates for ratepayers.

FERC indicated that they believe paying demand response resources the LMP will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO.

The Commission emphasized that these findings reflect a recognition that it is appropriate to require compensation at the LMP for the service provided by demand response resources participating in the organized wholesale energy markets only when two conditions are met:

- The first condition is that the demand response resource has the capability to provide the service, i.e., the demand response resource must be able to displace a generation resource in a manner that serves the RTO or ISO in balancing supply and demand.
- The second condition is that the payment of LMP for the provision of the service by the demand response resource must be cost-effective, as determined by the net benefits test described herein.

Rather than requiring compensation at LMP in all hours, the Commission requires the use of the net benefits test described herein to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching those resources. When the above-noted conditions of capability and of cost-effectiveness are met, it follows that demand response resources that clear in the day-ahead and real-time energy markets should receive the LMP for services provided, as do generation resources. LMP represents the marginal value of an increase in supply or a

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[37] https://www.utilitydive.com/news/updated-supreme-court-upholds-ferc-order-745-affirming-federal-role-in-de/412668/

[38] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

reduction in consumption at each node within an ISO or RTO, i.e., LMP reflects the marginal value of the last unit of resources necessary to balance supply and demand.

Barriers to demand response participation at the wholesale level identified by commenters include the lack of a direct connection between wholesale and retail prices, lack of dynamic retail prices (retail prices that vary with changes in marginal wholesale costs), the lack of real-time information sharing, and the lack of market incentives to invest in enabling technologies that would allow electric customers and aggregators of retail customers to see and respond to changes in marginal costs of providing electric service as those costs change. The Commission concludes that paying LMP can address the identified barriers to potential demand response providers.

Removing barriers to demand response will lead to increased levels of investment in and thereby participation of demand response resources (and help limit potential generator market power), moving prices closer to the levels that would result if all demand could respond to the marginal cost of energy. To that end, the Commission emphasizes that removing barriers to demand response participation is not the same as giving preferential treatment to demand response providers; rather, it facilitates greater competition, with the markets themselves determining the appropriate mix of resources, which may include both generation and demand response, needed by the RTO and ISO to balance supply and demand based on relative bids in the energy markets.

The Commission disagrees with commenters who contend that demand response resources should be paid LMP-G in all hours. First, as discussed above, demand response resources participating in the organized wholesale energy markets can be cost effective, as determined by the net benefits test described herein, for balancing supply and demand and, in those circumstances, it follows that the demand response resource should also receive compensation at LMP. Second, such comments largely rely on arguments about economic efficiency, analogizing to incentives for individual generators to bid their marginal cost. These arguments fail to acknowledge the market imperfections caused by the existing barriers to demand response, also discussed above. In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets “expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability.”

In the absence of market power concerns, the Commission does not inquire into the costs or benefits of production for the individual resources participating as supply resources in the organized wholesale electricity markets and will not here, as requested by some commenters, single out demand response resources for adjustments to compensation. The Commission has long held that payment of LMP to supply resources clearing in the day-ahead and real-time energy markets encourages “more efficient supply and demand decisions in both the short run and long run,” notwithstanding the particular costs of production of individual resources.

Some arguments advocating paying LMP-G rather than LMP assume that demand response resources need to purchase the energy in day-ahead markets or by other means and then “resell” the energy to the market in the form of demand response. However, The Commission does not view demand response as a resale of energy back into the energy market. Instead, as the Commission also explained in EnergyConnect and in Order No. 719-A, the Commission asserts jurisdiction with respect to demand response in organized wholesale energy markets because of the effect of demand response and related RTO and ISO market rules on Commission-jurisdictional rates.

B.2 LMP-G Arguments

Many econometricians have argued that Demand Response resources should be compensated LMP-G rather than LMP[39].

They argue that “the customer has an option to purchase electricity to satisfy demand with the strike price in the option set at the retail price: if you exercise the option and consume you pay the retail price, but if you don’t exercise the option, and don’t consume, you don’t pay the retail price. As always with other options, the market value of the option is the difference between the market price of the product and the strike price of the option. Think of the analogy to stock options. If the stock market price is $50 and you have an option to buy the stock at $30, then the value of the option is $20. In the parlance of the Order 745 discussion, the strike price is treated as “G” and the market value of the demand response is “LMP-G.”

They have also indicated that paying LMP may introduce a double payment problem. They indicate that “there are many examples of perverse incentives created by the demand response compensation at LMP. For instance, distributed generation built just before the customer meter would be worth much less than the same plant built just after the customer meter. Even setting aside the (related) perverse incentives of retail net-metering, you should build you next generator on the customer side of the meter; you could use the generator output without changing your actual consumption; you would not be seen as buying from the grid so you would save the LMP; and you would be credited for a “negawatt” and be paid the LMP again!”

They also indicate that “the money to pay for demand response has to come from somewhere, and it comes precisely from the wholesale generators as a group (this is the point of the net benefits test). Demand response will reduce short-term energy market prices, allowing the mandate to collect the extra demand response costs from the remaining loads without increasing the apparent average short term price to those loads. Hence, we see the rule operating as a regulation to further induce supply-side price suppression.”

B.3 Additional Resources

The following articles provide a number of views related to the FERC 745 ruling.

https://www.greentechmedia.com/articles/read/supreme-court-rules-in-favor-of-demand-response#gs.6AN95=g
https://www.utilitydive.com/news/updated-supreme-court-upholds-ferc-order-745-affirming-federal-role-in-de/412668/
http://www.scotusblog.com/2016/01/opinion-analysis-court-blesses-lower-wholesale-power-rates/
https://www.forbes.com/sites/peterdetwiler/2016/01/25/scotus-finds-strongly-in-favor-of-demand-response/#63cc9516408d
https://sites.hks.harvard.edu/fs/whogan/Hogan_DR_pricing_021516.pdf

[39] https://sites.hks.harvard.edu/fs/whogan/Hogan_DR_pricing_021516.pdf

TAB J

EXHIBIT "J"

referred to in the Affidavit of

DAVID SHORT

Sworn October 25, 2019

Commissioner for Taking Affidavits

UTILIZATION PAYMENTS DISCUSSION

Demand Response Working Group

March 1, 2018

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Purpose

- Continue discussion of the merits of DR utilization payments by reviewing stakeholder feedback received

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Recap

- The discussion on utilization payments for DR was a priority item put forth by stakeholders in the 2017 DRWG work plan
- The IESO commissioned a discussion paper to provide research on utilization payments to facilitate an informed discussion
  - At the Nov 16 DRWG meeting, Navigant presented the topics from the Utilization Payment discussion paper and facilitated a discussion on utilization payments
  - At the Jan 30 DRWG, IESO reviewed and discussed findings from the Navigant Utilization Payment discussion paper with stakeholders

Feedback

- The IESO is looking for compelling rationales from the DRWG on the merits of DR utilization payments
- Feedback was requested to hear DRWG member perspectives and observations
- Feedback received generally falls into three categories:

Impact on Utilization

Fairness

Market Efficiency

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Utilization Frequency

Stakeholder Comment

Utilization payments would incentivize residential DRMPs to bid lower energy prices, which could increase utilization.

- *In theory, providing a payment for DR utilization would incent participants to lower energy bid prices, which could lead to increased utilization of DR resources*
  - *Stakeholder feedback indicates that utilization payments may not lead to increased utilization*
- *Would a utilization payment reduce DR energy bid prices to materially impact utilization frequency?*
  - *The IESO has provided historical pricing statistics in a presentation at the Sep 12, 2017 DRWG meeting*

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Utilization for RPP Customers

Stakeholder Comment

Residential customers on a regulated price plan (RPP) are not exposed to wholesale pricing. Exposure to high market pricing through utilization payments for residential customers has a high likelihood of improving performance of the resource and increasing activations.

- *Some participants may not be exposed to wholesale electricity pricing and as a result may not receive the benefit from DR activations*
- *The IESO is requesting more detail from stakeholders on the materiality of the matter including MWs impacted and quantifying likely bid price behaviour change from a utilization payment*

Utilization Payments in Past DR Programs

Stakeholder Comment

CBDR resources were prepared to activate at $200/MWh provided they received this payment demonstrating that revenue is a strong incentive for activation.

- *The historical contracting programs required DR energy bids to be priced at $200/MWh. Once the $200 price requirement was removed for HDR resources, the IESO observed that the majority of DR bids were priced by participants much higher than $200/MWh*
  - *Implies DR participant's value of energy consumption is much higher than this level*

Utilization Payment Lowering Costs

Stakeholder Comment

If paying a DR resource for utilization reduces the cost of electricity, then DR payments are positive system benefit.

- *The IESO agrees that if a DR utilization payments could reduce total system costs then it does yield a positive system benefit*
  - *However, providing a utilization payment may reduce the cost of the energy price of electricity for that event but other system costs such as uplift and capacity costs would increase*
- *Introduces a market inefficiency issue because one resource type receives an unfair advantage*
- *On balance, it is not clear that there would be a positive system benefit*

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Utilization Costs

Stakeholder Comment:

There are costs to activate DR including opportunity costs and process costs. Utilization payments help offset those costs.

- *DR participants may incur costs to be utilized for DR. However, energy resources have the capability to reflect these costs in their energy bid price. While this may result in infrequent economic utilization, it is reflective of the energy market competitiveness of the resource.*

Negawatts and Megawatts

Stakeholder Comment

IESO should support DR utilization payments based on the premise that "negawatts" and megawatts are functionally and economically equivalent

- *The IESO agrees that resources should be treated equally for the type of service provided*
- *The IESO has explored the impact of "negawatts" and megawatts through examples in the following slides.*

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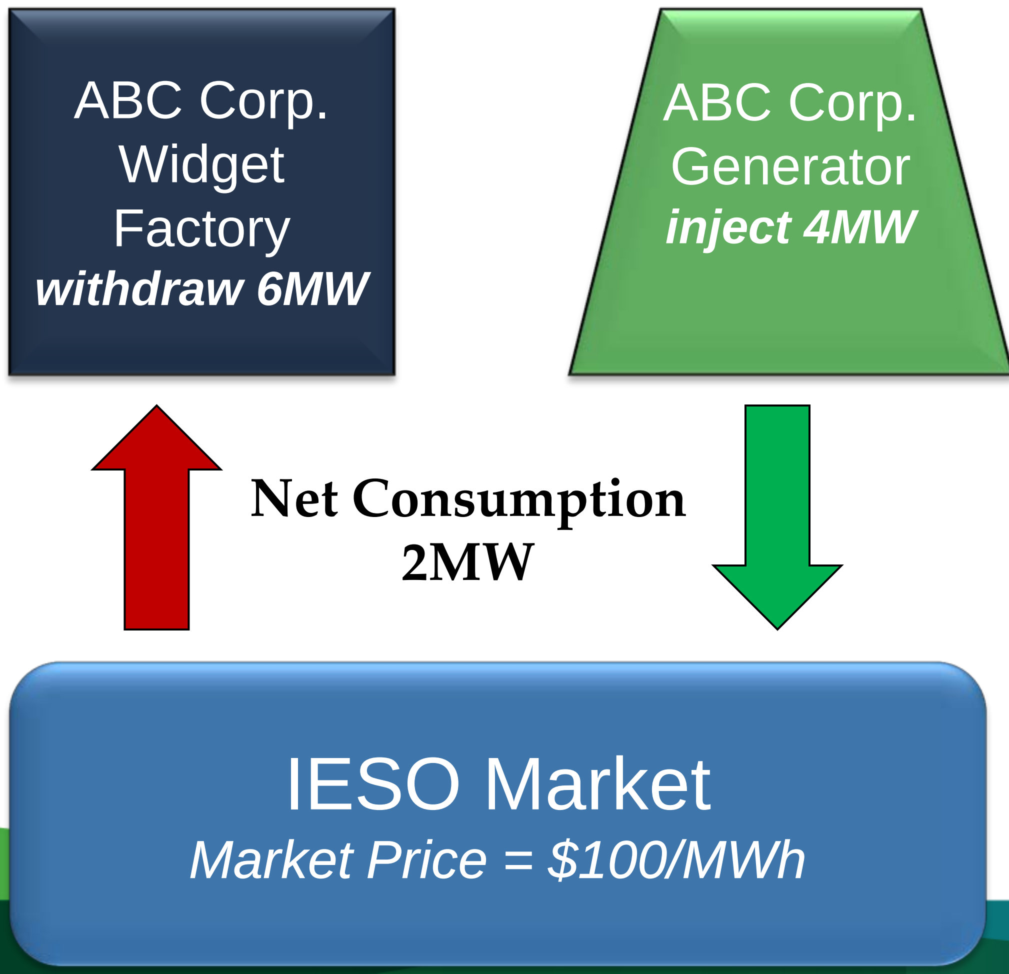
Negawatts and Megawatts

IESO Example 1

- Assume ABC Corporation owns a widget factory and a generator each individually participating in the IESO market

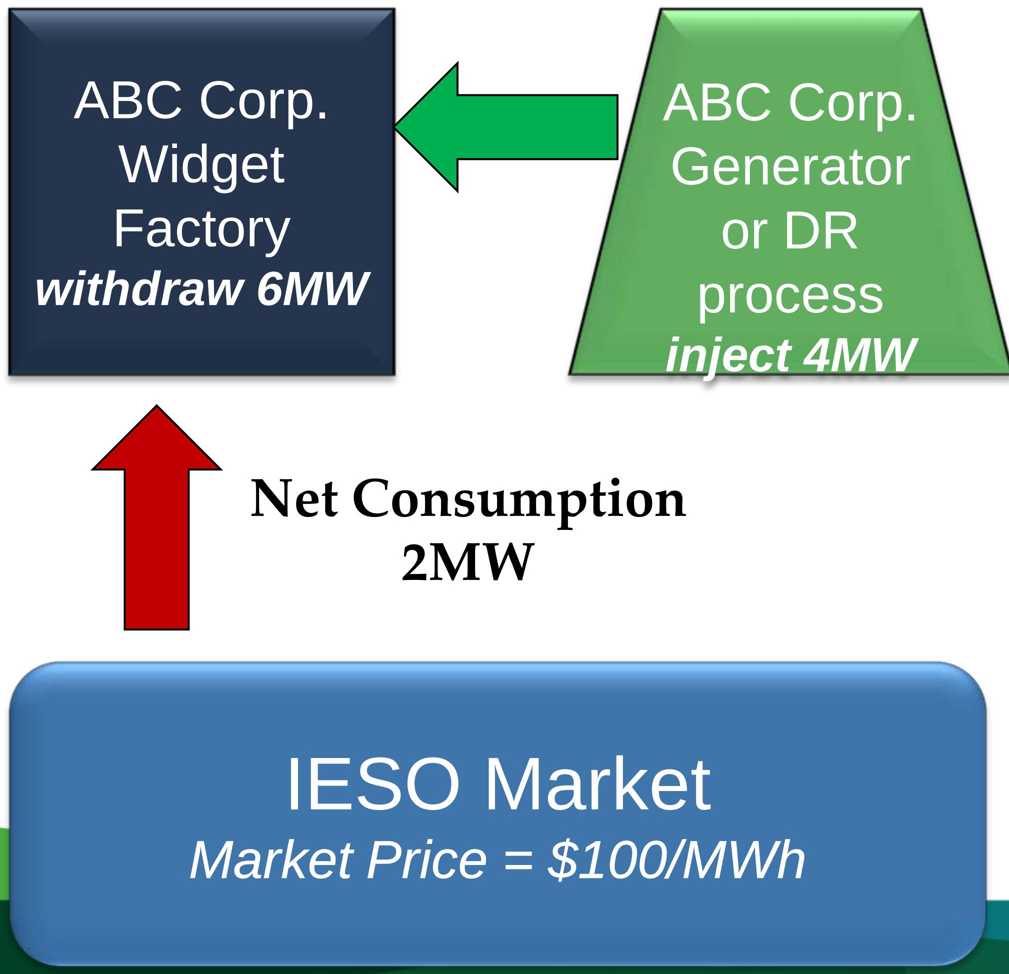


ABC Corp. Energy Bill	
Net Consumption MW	2MW (6MW-4MW)
Energy Price	× $100
Net Settlement	**$200**

Negawatts and Megawatts

IESO Example 2

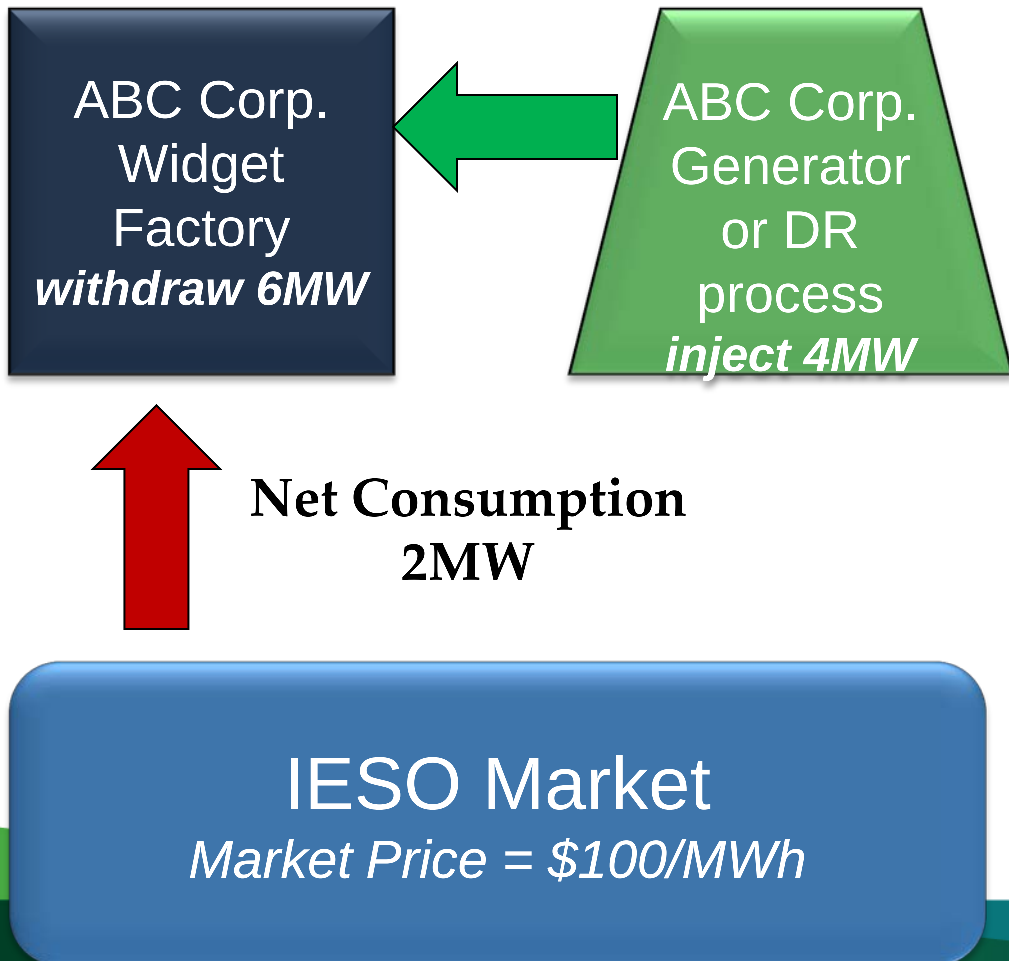
- Now assume ABC Corp. widget factory participates in DR by installing a behind-the-meter generator or interrupts production with the same 4MW
- Both examples yield the same settlement result



ABC Corp. Energy Bill	
Net Consumption MW	2MW (6MW-4MW)
Energy Price	× $100
Net Settlement	**$200**

Negawatts and Megawatts

IESO Example 2



- Now assume ABC Corp. widget factory participates in DR by installing a behind-the-meter generator or interrupts production with the same 4MW
- **If a DR utilization payment is made, ABC Corp. receives an extra payment**

ABC Corp. Energy Bill		
Net Consumption MW	2MW (6MW-4MW)	
Energy Price	× $100	
Net Settlement	**$200**	**+ Utilization Payment**

Negawatts and Megawatts

- The previous examples illustrate that the current practice of **not** providing a utilization payment is equal treatment for resources providing "negawatts" and megawatts
  - Is there anything the IESO has missed or not considered?
- Example 1 and Example 2 should yield the same settlement impact because its impact to the IESO market is the same. However, if a DR utilization payment is made in Example 2, the ABC Corp receives an additional payment, which is unequal treatment

IESO OBSERVATIONS

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Observations

- Some indication that utilization payment for load **not** exposed to market price identifies a potential area for further discussion
  - The IESO is interested in receiving more detailed information from stakeholders on materiality and likely behaviour change
- No clear indication that utilization payments would increase activation for most load types
  - Stakeholders have indicated VOLL is very high and sometimes in excess of MMCP
- Based on the "Negawatt and Megawatt" example, it appears that current practice for compensating DR utilization is equivalent treatment and a DR utilization payment would introduce non-equivalent treatment

Next Steps

- The IESO does see merit in continuing discussion on utilization payments for participants **not** exposed to market pricing but it is unclear to the IESO on the impact of utilization payments on these types of participants
  - The IESO is requesting more detail from stakeholders on the materiality of the matter including MWs impacted and quantifying likely bid price behaviour change from a utilization payment
- For resources exposed to market pricing, does not appear to have merit to continue discussions for now
- Based on the quantity of stakeholder feedback received, the IESO does not see strong interest from the DRWG on this topic
  - Only two members submitted feedback on this issue and members declined to present their views for discussion at the DRWG
  - Unclear if this continues to be a priority item to the working group

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Next Steps

- Feedback can be sent to engagement@ieso.ca by Mar 16, 2018.
- The IESO is also willing to meeting with stakeholders individually if they would like to share information not suited for the wider DRWG audience

TAB K

EXHIBIT "K"

referred to in the Affidavit of

DAVID SHORT

Sworn October 25, 2019

Commissioner for Taking Affidavits

Energy Payments for Economic Activation of DR Resources

October 10, 2019

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History and Context

- Energy payments for the utilization of demand response (DR) resources has been an ongoing topic of discussion at the Demand Response Working Group (DRWG)
- In 2017, the IESO commissioned Navigant to prepare a discussion paper in order to facilitate an informed discussion on the topic. The Navigant paper concluded, in part, that the "arguments for and against utilization [energy] payments are nuanced and prudent. Responsible stakeholders can arrive at different conclusions based on preferences for evaluation criteria" and that "Additional effort is required to estimate the quantum of the impacts"
- The IESO discussed the findings of the Navigant report with stakeholders at the DRWG in 2018 (refer to pre-reading materials)
- Stakeholder interest in energy payments was renewed in early 2019 as a result of the proposed market rule amendments to enable the then "transitional capacity auction", now "capacity auction"
- Given that this is a complex issue and would be a substantive change to Ontario's energy market, the IESO determined that a broader stakeholder engagement was needed to advise on the issue

Today's Overview

1. Introductions
2. Engagement plan overview
3. Develop a common understanding of the energy payment issue
   - Q and A on pre-reading materials
   - Review of problem statement
4. Review draft research and analysis scope
5. Break-out discussion on draft research and analysis scope
6. Summary

Engagement Objectives for Today's Meeting

- Develop a common understanding of the energy payment issue amongst all stakeholders
- Review the high-level proposed approach and schedule for undertaking this work with stakeholders
- Facilitate a break-out discussion to ensure the scope of the research to be conducted considers different stakeholder perspectives

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2. STAKEHOLDER ENGAGEMENT PLAN: OVERVIEW AND APPROACH

Stakeholder Engagement Plan

- To be conducted in accordance with the IESO's approved engagement principles
- Draft engagement plan posted for comment on August 22
- Engagement Objective
  - Provide a forum for stakeholders to advise on the research and analysis required to help inform the IESO's decision on whether demand response (DR) resources will be compensated with energy payments for in-market activations.

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Stakeholder Engagement Plan continued

- Feedback from stakeholders is needed on:
  - Inputs and outputs of third-party research and analysis to inform IESO's decision on the energy payment issue
  - Other information that should be considered
  - The IESO's draft decision and rationale on whether DR resources will be compensated with energy payments for in-market activations

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Engagement Schedule

August 22, 2019	Engagement launched and Draft Engagement Plan posted for comment
October 10, 2019 *(Today)*	Review engagement plan and objectives Review and gather feedback on draft scope of research and analysis
November 2019	Final study scope and study plan
Q1 2020	Draft research findings and/or analysis for stakeholder review
Q1 2020	Final research findings and analysis
May 2020	Draft IESO decision and rationale for stakeholder review
June 2020	Final IESO decision and rationale

- IESO will be gathering stakeholder feedback throughout the engagement
- Any additional feedback on the draft engagement plan can be submitted to engagement@ieso.ca

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3. DISCUSSION OF THE ENERGY PAYMENT ISSUE AND PROBLEM STATEMENT

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Purpose

- Develop a common understanding of the energy payment issue amongst all stakeholders
- To seek feedback and input on the problem statement that will be answered at the end of this engagement

Overview of the Issue

- Demand Response can be provided in Ontario by dispatchable loads and Hourly Demand Response (HDR) resources
- When a dispatchable load or HDR resource is activated to reduce consumption based on "in-market" signals in the energy market, i.e., when the applicable market price is greater than the resource's energy bid, the DR resource does not currently receive an energy payment for reducing its consumption.
  - Demand Response Market Participants (DRMPs) that have a capacity obligation, awarded through the auction process, must register as either a dispatchable load or HDR resource. The DRMP fulfills its capacity obligation by making such capacity available in the energy market by submitting bids. The energy bid for DRMPs is required to be greater than $100 and less than $2000
  - Dispatchable loads can participate in the energy market with or without a DR capacity obligation
  - A description of how dispatchable loads and HDR resources are activated is described in the slides that follow

Activation of Dispatchable Loads

- Dispatchable loads are activated in the energy market on a 5-minute basis
- In-market activation occurs when the shadow price, a 5-minute price determined by the constrained real-time run of the dispatch algorithm - is greater than the dispatchable load's energy bid price
- Under the current design, the settlement process reconciles any difference between the energy bid and the market clearing price

Activation of HDRs

- HDRs are activated in the energy market on an hourly basis, for a time block up to 4 hours
- In-market activation occurs when the pre-dispatch shadow price at the node – determined through the constrained run of the dispatch algorithm - 3 hours prior to the activation, is greater than the HDR's energy bid price
- HDRs are provided with notice of the activation 2.5 hours before the start of the first dispatch hour to which it relates

Out-of-Market Activations

- HDR resources can also be activated out-of-the market for a capacity test or emergency control action
  - In these cases, the HDR resources can be activated when they are not "in-market", i.e., even if the pre-dispatch shadow price 3 hours prior to the activation is lower than the resource's energy bid price
- Compensation for out-of-market activation of HDR resources was recently discussed through the DRWG and is out of scope for this engagement

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Establishing a Common Understanding of the Energy Payment Issue

- The following pre-reading materials were circulated in advance to build stakeholder understanding of the issue:
  - Navigant Demand Response Discussion Paper (December 2017)
  - DRWG presentations where the Discussion Paper findings were discussed (January and March 2018)
  - FERC Order 745 as supplementary background
- Do you have any questions, based on the pre-reading materials and concepts described in the earlier slides, to better understand the:
  - Characterization of the energy payment issue; and,
  - Factors considered in the previous work?
- Are there any other materials that should be considered within this stakeholder forum?

Stakeholder Submissions

- Stakeholders are invited to provide their own submissions that help develop an understanding of the energy payments issue for consideration in this engagement
  - Please identify interest in doing so by emailing engagement@ieso.ca by October 25, 2019
  - Submissions are requested by November 13, 2019 so that these materials can be posted and reviewed in advance of the next engagement meeting (November 27, 2019) **dates to be confirmed*
  - Stakeholders will be invited to answer questions on their submissions at the next engagement meeting

The Proposed Problem Statement

Should demand response resources receive energy payments when they are activated in-market?

Definitions

- Where:
  - Demand Response refers to a resource that that is registered with the IESO as either a dispatchable load or HDR
  - Energy Payment refers to a payment for reducing energy consumption that is based on the amount of energy reduced and the applicable market price
  - In-Market Activation refers to the resource being scheduled to reduce consumption when the applicable market price is greater than the resource's energy bid

Feedback on the Problem Statement

- Does the draft problem statement reflect the question that needs to be answered at the end of this engagement? If not, please provide and describe an alternate statement for consideration
- Stakeholders are invited to provide written feedback by October 25, 2019 by e-mailing engagement@ieso.ca

4. DRAFT SCOPE OF RESEARCH AND ANALYSIS

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Purpose

- To review the draft scope of research and analysis, which will be used to inform the IESO's answer to the problem statement (discussed as a previous agenda item) and seek stakeholder feedback

Proposed Decision Framework

Problem Statement: *Should DR resources receive energy payments for in-market activations?*

Criteria: *Is there an overall net-benefit to consumers over the long-term?*

Research and Analysis: *will form the basis to which the criteria will be applied (will be supported by the Brattle Group)*

Draft Scope of Research and Analysis

The research and analysis will answer the following questions for both current market and the market design after the Market Renewal Program is implemented (where applicable):

1. **What is the relevant Ontario context and history?**
   - History of DR programs and structures, current levels of DR participation and status quo outlook for future participation
2. **What are the economic first principles that drive the activation decision for demand response resources?**
   - Including: marginal cost of dispatch, wholesale market prices, impact of “retail” rates, impact of activation payments which may or may not apply
3. **How are in-market activations compensated in other jurisdictions and what are the key takeaways for Ontario?**

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Draft Scope of Research and Analysis continued

4. **If compensation is provided, what could the compensation model look like in Ontario?**
    - The purpose of this question is to provide the lens through which the benefits, risks and implications can be assessed; it should not be viewed as an indication of the answer / outcome to the problem statement
5. **What are the benefits, risks, and implications of a) the status quo, and b) providing DR with energy payments in the near and longer terms?**
    - Considers impacts on: market and economic efficiency, competition and level of DR participation, cost-recovery, consistency and fairness vis-à-vis other market participants and other indirect impacts

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Stakeholder Feedback on the Criteria and Scope of Research and Analysis

- Feedback on the scope of research and analysis will be collected through the upcoming break-out discussions
- Stakeholders are also invited to provide written feedback, on the following questions, by October 25, 2019 by e-mailing engagement@ieso.ca
  - Is the decision criteria appropriate?
  - What else should be considered in scope of the research and analysis and why?
  - Are there any questions in the scope of the research and analysis that should be refined or removed? If so, why?

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5. BREAK-OUT DISCUSSIONS

Break-Out Discussions

- The purpose of the break-out discussions is to build awareness of the various perspectives and considerations related to this issue
- The discussion will help identify additions / refinements to the scope of the research and analysis that will be carried out to inform the IESO's decision
- The focus question for the discussion is:

What are the potential pros and cons of providing DR resources with energy payments for in-market activations?

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Break-Out Discussion Logistics

- Break into small groups
- Discuss focus question as a small group (35 mins)
  - Please write key discussion points on flip-chart paper with markers provided
- Report-back key discussion to all (5 mins per group)
  - Elect one presenter to provide the highlights
- IESO will collect, record, and post flip-chart notes on engagement webpage
- Webinar participants are invited to participate in a virtual break-out discussion

Break-Out Discussion Focus Question

What are the potential pros and cons of providing DR resources with energy payments for in-market activations?

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6. SUMMARY AND NEXT STEPS

Summary of Stakeholder Feedback

Feedback Topic	Details
Understanding the energy payments issue	• Stakeholders to signal their intent to provide submissions that help develop an understanding of the energy payments issue
Draft Problem Statement	• Does the draft problem statement reflect the question that needs to be answered at the end of this engagement? If not, please provide and describe an alternate statement for consideration
Decision Criteria and Scope of Research and Analysis	• Is the decision criteria appropriate? • What else should be considered in scope of the research and analysis and why? • Are there any questions in the scope of the research and analysis that should be refined or removed? If so, why?

- All feedback is requested by October 25, 2019
- Please use the feedback form provided on the engagement webpage

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Next Steps

- Next engagement meeting tentatively planned for November 27, 2019
- Scope of this meeting will include:
  - Discussion of consideration of feedback received following today's meeting
  - Discussion of stakeholder submissions
  - Final scope of research and analysis to be carried out

TAB L

EXHIBIT "L"

referred to in the Affidavit of

DAVID SHORT

Sworn October 25, 2019

Commissioner for Taking Affidavits

Hourly Demand Response (HDR) Testing Update

Demand Response Working Group

April 25, 2019

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Purpose

- Background
- Performance
- HDR Testing Criteria
- HDR Test Activation Protocol – Update

HDR Testing Background

- As per *Market Rules Chapter 7, 19.4.11* and *19.5.7*, IESO may direct HDR resources to perform activation up to a maximum of two test activations per commitment period
- Testing allows IESO to verify that a capacity obligation is deliverable by the HDR resource
- IESO test activations last for 4 hours per test and all HDR resources are tested in each commitment period
- HDR resources receive non-performance charges for failing a test activation primarily through two settlement charges (Capacity & Dispatch Charge)
- IESO may choose to not test a HDR resource twice within a commitment period based on its successful historical performance in test and in market activations

HDR Testing Background

- HDR receive non-performance charges for failing a test activation primarily through two settlement charges:
  - **Capacity Charge (failure to provide capacity)**
    - Availability Payment for the month is clawed back
    - Capped at one charge per month
  - **Dispatch Charge (failure to follow dispatch)**
    - Availability Payment for the MW the DR resource failed to curtail multiplied by the hourly demand response auction clearing price
    - This charge is multiplied by a non-performance factor (1x, 1.5x, or 2x) depending on whether activation is during a peak period
- Test failure can be referred to IESO's Market Compliance and Assessment Division (MACD) as a potential market rule non-compliance
- As per *Market Rules Chapter 7, 19.4.8* and *19.5.4*, IESO may disqualify participation from future DR auctions when a resource consistently fails to provide performance as per the requirements

HDR Testing Criteria

- HDR test performance is evaluated based on a resource's ability to:
  - Deliver capacity, measured as the average load reduction over a 4-hour test period, within a 20% deadband, and
  - Follow dispatch, measured as HDR resource's output against its dispatch signals in each interval, within a 15% deadband
- Testing in the ICA will require participants to demonstrate 100% of their capacity obligation
- HDR testing criteria will evolve in TCA as they review qualification and performance measures
- This could include a move to a measure of 100% of a facility's capacity obligation, without deadbands. This will be further explored in TCA Phase 2

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HDR Testing Performance

- IESO tests all Physical and Virtual HDR resources in each commitment period
- HDR can request to be tested at another time if they are unable to proceed with the test activation
  - Must file non-performance event; and
  - Bids should reflect inability to provide load reduction
- From Feb 2018 – Jan. 2019, only ~42% of HDR resources cleared testing
  - ~58% failure rate
  - ~39% failed in all hours (4 hour test)

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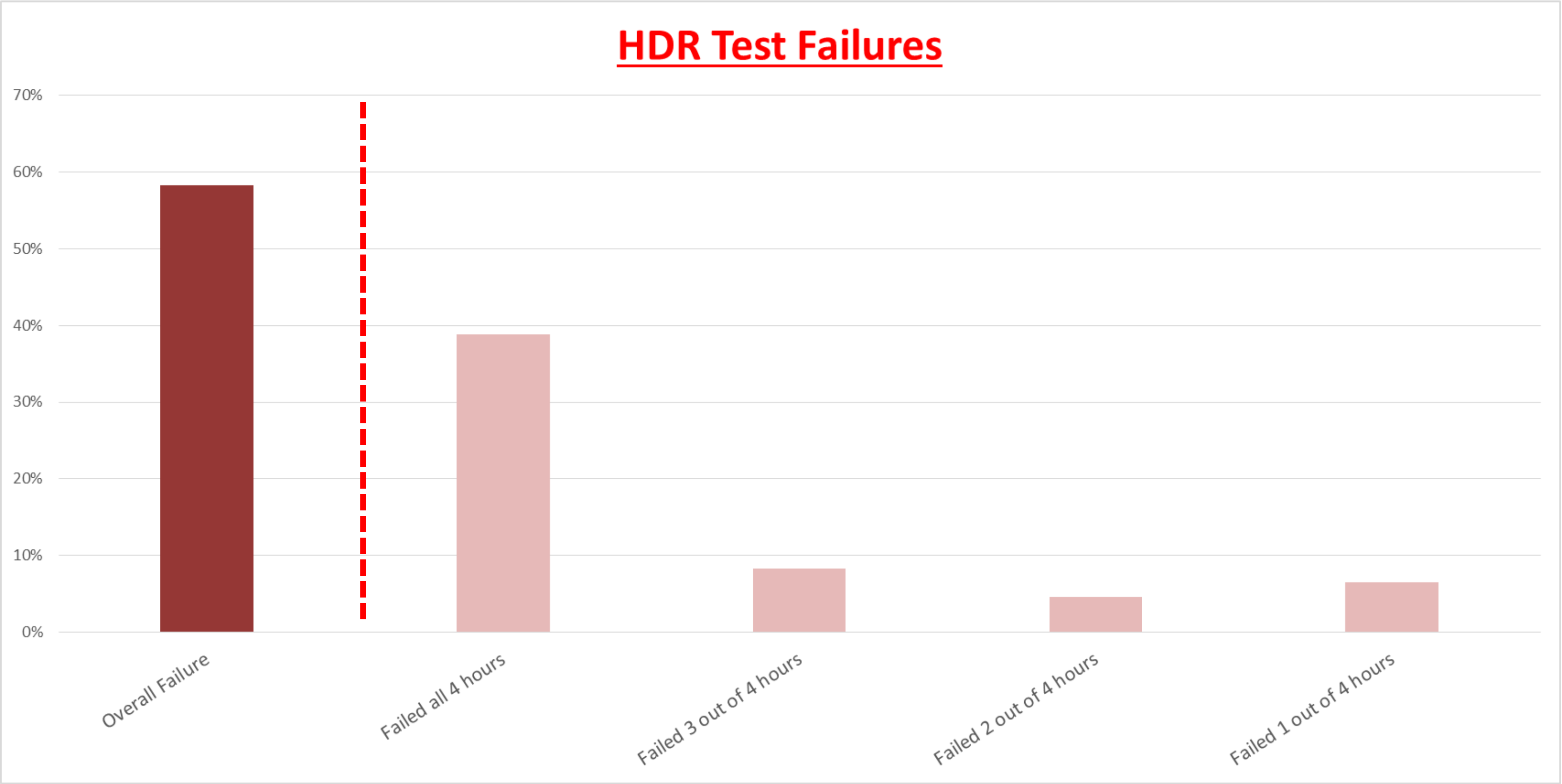
HDR Testing Performance



	Overall Failure	Failed all 4 hours	Failed 3 out of 4 hours	Failed 2 out of 4 hours	Failed 1 out of 4 hours
Percentage	58%	39%	8%	5%	6%

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HDR Test Activation Protocol

- As presented during the last DRWG, the IESO will be updating the testing protocol
  - Day ahead notification via phone call will be removed
  - Standby notification will be issued day ahead
  - IESO will also issue a Advisory Notice in advance of the standby notification (to confirm test activation)
- Changes will take effect at the start of the upcoming summer commitment period (May 1, 2019)

ONTARIO ENERGY BOARD

EB-2019-0242

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

APPLICATION TO REVIEW AMENDMENTS TO THE MARKET RULES MADE BY THE INDEPENDENT ELECTRICITY SYSTEM OPERATOR

AFFIDAVIT OF DAVID SHORT
(Sworn October 25, 2019)

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