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.

EVIDENCE OF THE INDEPDENENT ELECTRICITY SYSTEM OPERATOR

November 8, 2019

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PART I - INTRODUCTION

1. The Independent Electricity System Operator's ("**IESO**") Board of Directors ("**IESO Board**") approved MR-00439-R00 to R05 (the "**Amendment**") enabling the IESO's Transitional Capacity Auction (**"TCA"**) on August 28, 2019, with an effective date of October 15, 2019.

2. The Amendment is a first step in broadening and increasing competition in the IESO's capacity auction and addressing a forecast summer 2023 capacity gap of approximately 4,000 MW.

3. As further explained herein, the IESO opposes the Association of Major Power Consumers in Ontario (**"AMPCO"**) Application request that the Amendment be revoked, and the TCA be suspended, until such time as the IESO amends other market rules to provide for energy payments to demand response (**"DR"**) resources in the energy market. It is the IESO's considered opinion that:

(a) It is important for reliability purposes to launch the TCA in December 2019 and to progress the TCA in a phased manner which provides the IESO and TCA participants the opportunity to learn and, as necessary adapt, in advance of the forecast 2023 capacity gap. It is the IESO's view that it would be imprudent, risking future reliability, to delay the TCA and launch it closer to the eve of the 2023 capacity gap;

(b) The TCA will provide an opportunity for existing non-committed generators coming off contract, which may in the absence of the TCA choose to wind down their operations to the potential detriment of Ontario reliability and the interests of Ontario consumers; and

(c) The TCA will increase competition and benefit consumers by allowing for participation by new capacity resource types and increasing the supply of capacity into the auction.

4. The IESO disagrees that AMPCO's members or other DR resource participants will be materially harmed, let alone unjustly discriminated against, by proceeding with the TCA prior to resolving the issue of energy payments for DR resources. No DR

participants who participated in the Demand Response Auction ("**DRA**") have provided any evidence of potential harm. Further:

(a) AMPCO is requesting a fundamental change to Ontario's energy (not capacity) market design and market rules by proposing energy payments for loads and this issue is very complex, particularly in the context of Ontario's hybrid electricity market, and warrants necessary study and analysis. The IESO has prioritized the concerns of AMPCO members by undertaking a comprehensive stakeholder engagement and third party study on energy payments for DR resources, which will be completed in Q2 2020 following which the IESO will make a final determination and, as necessary, initiate market rule changes.

(b) There will be no harm, or negligible harm, to DR resources in the interim. DR participants in the DRA have rarely been economically activated in the energy market and the IESO does not anticipate any material increase in DR activations over the period governed by the December 2019 TCA. DR participants will also be compensated for out-of-market activations, which is their only material exposure to activation.

5. The IESO is pleased to submit to the Board its written evidence, which is presented below in question and answer format.[1]

PART II - LEGAL AUTHORITY

A. Who is the IESO?

6. The IESO is a public agency, that is continued under the *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A (the "***Electricity Act***") and its responsible for maintaining the reliability of the provincial transmission grid, administering Ontario's wholesale electricity market and planning the province's bulk power system.

[1] Much of the evidence contained herein overlaps with and relies on the Affidavit of David Short, sworn on October 25, 2019, which the IESO submitted to the Board in response to AMPCO's Motion to Stay the operation of the Amendment. For coherence, we have reproduced portions of the said affidavit herein.

7. The IESO's authority under Part II of the *Electricity Act* includes making market rules: (1) governing the IESO-controlled grid; (2) establishing and governing markets related to electricity and ancillary services; and (3) establishing and enforcing standards and criteria relating to the reliability of electricity service or the IESO-controlled grid.

B. What is the IESO's process to amend the market rules?

8. The IESO's Board has ultimate authority and responsibility to amend market rules.

9. The IESO has developed a stakeholder engagement processes to consult with individuals and organizations for the purpose of informing the IESO's decision-making, including proposed market rule amendments. The IESO's stakeholder engagement processes are designed to promote transparency, efficiency and consistency.[2]

10. All proposed market rule amendments are considered by the IESO's Technical Panel, whose members are appointed by the IESO Board of Directors. The IESO's Technical Panel is composed of stakeholders that represent a broad range of electricity resources and constituencies in the IESO-administered markets. The Technical Panel provides advice to the IESO Board on proposed market rule amendments.

11. Each member of the Technical Panel casts a vote as to whether they are in favour of, or opposed to, proposed rule amendments along with the reason for their position. This information is then communicated to the IESO Board for its consideration in determining whether to approve proposed market rule amendments.

12. After the IESO Board has adopted or rejected a proposed amendment, information on the Board's decision with reasons is posted to the IESO's public website along with the approved amendments as applicable.

13. The IESO is also required to provide a copy of any adopted amendment, along with prescribed information, to the Board before the IESO publishes the amendment and the Board may, not later than 15 days after the amendment is published, revoke the amendment.

[2] The IESO guides its engagement processes in accordance with its Engagement Principles to ensure that the engagement activities follow an efficient and effective process which is conducted with integrity. Attached at **Tab "1"** are the IESO's Engagement Principles, undated.

PART III - THE TRANSITIONAL CAPACITY AUCTION

A. What is the Transitional Capacity Auction?

14. The purpose of the Amendment is to implement the TCA in Ontario. The TCA is the first step in evolving the IESO's existing capacity auction – the demand response auction ("**DRA**") – into a more competitive capacity auction that includes additional resource types and enhanced auction features that will improve reliability. The DRA was limited to dispatchable load and hourly demand response ("**HDR**") resources. The Amendment enables non-contracted and non-regulated dispatchable Ontario generators to participate in a capacity auction alongside dispatchable loads and HDR resources.

15. The Amendment largely leaves the foundation of the DRA in place and begins the transition to a broader capacity auction by expanding eligibility to participate in the TCA to resource types other than DR resources.

B. What does capacity mean in the context of the IESO-administered market?

16. 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.

17. At a high level, capacity can be provided by supply resources through energy injections or from loads in the form of demand response.

C. What is the IESO's plan for the TCA?

18. The TCA is the first step in evolving the DRA into a more competitive capacity auction that includes additional resource types and enhancing auction features that will improve reliability. Whereas in the past, most capacity in Ontario has been procured through long-term contracts, the TCA will be a market-based mechanism for securing needed incremental capacity.

19. The TCA will run on December 4, 2019 for a one-year commitment period of May 1, 2020 to April 30, 2021. The commitment period will consist of two seasonal obligation periods.

20. The successful participants in the TCA auction 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.

21. Following the TCA, 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 to improve reliability and market efficiency. Each phase is expected to require further changes to the market rules.

22. The IESO plans to increase the forward period[3] 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).

PART IV - THE DEMAND RESPONSE AUCTION

A. What is demand response?

23. Demand response refers to the change in end-user electricity consumption patterns due to fluctuating market prices. DRA participants who are called upon by the IESO provide capacity by refraining from consuming energy from the IESO-administered grid rather than, as in the case of generators, supplying energy to the grid.

B. What is the DRA?

24. The IESO introduced the DRA in 2015 as a means of securing demand-side capacity for the IESO-administered grid. The DRA differs from former Ontario Power Authority (**"OPA"**) DR programs in that it is a market-based program administered under the market rules and DRA participants are integrated into the IESO-administered market, as opposed to the former OPA contract based DR programs.

[3] A forward period is the time between the execution of the auction and the first day of the commitment period.

25. DR participants in the DRA (**"DRA participants"**) participate in the energy markets either (1) dispatchable loads that responds to a five-minute schedule, or (2) as Hourly Demand Response (**"HDR"**) participants where participation limited to hourly blocks (up to 4 hours per day) with activation notice required at least two hours in advance of the need.

26. The DRA procures capacity for (1) a summer commitment period which occurs from May 1 to October 31 and (2) a winter commitment period which occurs from November 1 to April 30.

C. What are the mechanics of the DRA?

27. DRA participants are required to submit offers in the DRA for quantities between 1 MW and the DR capacity for which they were qualified in the DRA pre-auction process and are allowed to use offer laminations reflecting the prices of providing various levels of capacity. The prices offered must represent the minimum prices at which the participant is willing to provide each incremental quantity of capacity.

28. DRA participants must be willing to provide DR capacity – by reducing their consumption – starting on the first day of the commitment period, failing which they are subject to non-performance charges.

29. After DRA participants submit their offers, the offers are stacked against the demand curve to determine the clearing price for each zone and for each commitment period. The process of determining the auction clearing price is summarized in Market Manual 12.0.

30. After running the auction, the IESO communicates a Public Post-Auction Report to the public and a private Post-Auction Participant Report to market participants.

31. All successful DRA participants in a zone receive the same availability payment per MW day for their capacity obligation. This is referred to a "price as cleared"[4] where all successful participants are paid the same availability payment. As such, assuming resources offer into the auction at or near their costs, lower priced resources would

[4] *Price as cleared* is a standard auction and energy market mechanism where all successfully scheduled resources are essentially paid the highest price for that zone.

receive more profits as compared to resources that clear near the final auction price. Typically a number of auction participants are not price competitive, do not clear the auction and do not receive an obligation to supply capacity.

32. DRA participants who have incurred a DR capacity obligation through the DRA receive a monthly payment for every month of the commitment period for being available to supply capacity if called upon (referred to as an availability payment).

D. How are DRA resources activated or called upon?

33. All DRA resources are expected to be available to reduce their consumption during the summer commitment period from 12:00 to 21:00 EST, and during the winter commitment period from 16:00 to 21:00 EST.

34. Dispatchable load resources are activated (dispatched automatically by the IESO's Dispatch Scheduling Optimization software) on a 5-minute interval if the bid in the energy market is economic, either to meet Ontario's provincial need or a local energy need.

35. HDR resources have restrictions on their ability to be reduce consumption so they require a standby notice from the IESO at any time between 15:00 EST day-ahead up to 07:00 EST on the day of. HDR resources that are on standby can then receive an activation at least two hours in advance for one to four hour hourly blocks of reduced consumption – and only if they are economic compared to other resources for the hour(s) they are activated. HDR resources can only receive one activation per day.

E. What's the frequency for the activation of DR resources under the DRA?

36. DRA participants have been activated in the energy market in very limited circumstances since the DRA was launched in 2015. This is likely due to the relatively high prices at which DRA participants have bid into the energy market.

37. During this period, the Hourly Ontario Energy Price (**"HOEP"**) has averaged approximately $25/MW. During the same period, dispatchable load bid prices have averaged approximately $1500/MWh and HDR bid prices have averaged approximately $1700/MWh.

38. HDR resources have only been economically activated on one occasion since the introduction of the DRA in 2015. The Market Surveillance Panel of the Ontario Energy Board noted, in its Monitoring Report of the IESO-Administered Markets published in May 2017, that “the likelihood of an activation is remote”.[5] The Panel observed that between May and December 2016, 82% of HDR resources offered bid prices were $1999/MWh while the remaining 18% of HDR resources offered bid prices were $500/MWh. The Panel further concluded that any bid price over $220/MWh would not have been activated during the period.

39. Dispatchable loads have been economically dispatched less than 1% of the time over that same period.[6] These activations generally occur due to localized short-term price spikes resulting from contingencies such as unanticipated generation and transmission outages.

PART V - ENERGY PAYMENTS FOR DR RESOURCES

A. What are energy payments for DR resources?

40. Reference has been made in this proceeding to both “utilization payments” and “energy payments”. A utilization payment is a generic category which includes energy payments.

41. Energy payments for DR resources, which is what AMPCO is seeking in this Application, would be payments to loads that bid into the energy market and reduce energy consumption based on the applicable wholesale market clearing price.

B. How are DR resources treated in the IESO energy market?

42. The design of the IESO energy market was based on the recommendations of the Ontario Market Design Committee and on standard market design in other jurisdictions in North America.

43. Ontario’s energy market design, as codified in the market rules, provides that generators and loads may be either dispatchable or non dispatchable; and, that

[5] Attached at **Tab “2”** is the *Monitoring Report on the IESO-Administered Electricity Markets*, Market Surveillance Panel, dated May 2017.

[6] Attached at **Tab “3”** is the IESO Response to the Board Staff’s Interrogatory No. 8.

generators receive energy payments, but loads do not. Dispatchable loads bid prices in the energy market represent the point at which the load does not wish to consume electricity.

C. Did DR resources receive energy payments under the former OPA programs?

44. No, they did not. Starting in or about 2005 the former Ontario Power Authority (**"OPA"**) commenced a number of demand-side programs. The OPA held yearly procurement processes in which qualified participants bid for contracts to curtail their electricity consumption during periods of high system demand. These programs paid participants a monthly availability payment in return for the commitment to reduce load when called upon.

45. The final OPA DR program, called the Demand Response 3 (**"DR3"**) program, included utilization payments for activations. These payments, however, were not energy payments. They were contract payments set at a fixed rate of $200/MWh.

46. After the merger of the OPA and IESO on January 1, 2015, the IESO developed a transitional demand response program, governed by the market rules, called the Capacity Based Demand Response (**"CBDR"**) program. The CBDR program bridged the period from the DR3 contract expiration to the commencement of the DRA. For this period, the CBDR program continued some of the features of the DR3 program for the purpose of facilitating the transition to the DRA market-based structure under the market rules. For instance, the fixed rate $200/MWh utilization payment was included in the CBDR program until the expiration of DR3 contracts.

D. Do DRA participants receive energy payments?

47. No, they do not. As stated above, under Ontario's market design and the market rules, only generators are entitled to energy payments. DRA participants are solely entitled to monthly availability payments for the duration of their applicable commitment periods.

E. Will TCA DR participants receive energy payments?

48. No, the Amendment does not change the market rules governing payments in the IESO energy market. DR participants in the TCA will not receive an energy payment in the energy market because, as detailed above, loads are not entitled to receive energy payments under the market design and the market rules that have been in place since market opening.

F. Has the IESO previously studied the issue of energy payments for DR Resources?

49. Yes, the IESO previously commissioned a study of the merit of utilization payments for DR resources through its Demand Response Working Group ("**DRWG**").[7]

50. In the lead up to the launch of the DRA, some stakeholders had inquired about energy payments or utilization payments in the DRA, however, the immediate priority was to implement the DRA.

51. In early 2017, some DRWG members again raised this issue on the basis that "[o]ther jurisdictions (ISO-NE, NYISO, PJM) provide both energy and availability payments to DR [resources]" (p. 19). The IESO therefore agreed to further look into this matter (p. 22).[8]

52. In July 2017, the IESO, in consultation with the DRWG, engaged Navigant, an independent consultant with expertise in DR and electricity markets, to study and prepare a discussion paper on the merits of utilization payments.[9] Stakeholders were invited to provide submissions to inform the scope of Navigant's analysis, which included:

(a) Jurisdictional review - A summary of practices adopted in other markets;

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[7] The IESO established the DRWG in April 2014 to assist in the evolution of DR from a contracted resource into the energy market, as well as to inform the development of pilots and the DRA stakeholder engagement.

[8] Attached at **Tab "4"** is *DR Stakeholder Priorities for 2017*, Demand Response Working Group, dated January 31, 2017**.**

[9] Attached at **Tabs "5", "6", "7"** respectively are *Utilization Payments for DR Activations*, Demand Response Working Group, dated May 11, 2017; *Utilization Payments – 2017 Work Plan Item*, Demand Response Working Group, dated May 30, 2017; and *Utilization Payments – 2017 Work Plan Item*, "Scope of Discussion Paper", dated July 21, 2017.

(b) Economic efficiency - Arguments for/against providing utilization payments to DR resources in light of current and future system needs;

(c) DR Participation – The likely impacts of utilization payments to the dispatch frequency of HDR resources in Ontario;

(d) Wider market impacts - Spillover effects on the wider market.

G. What were the findings of the Navigant study?

53. On December 19, 2017 the IESO published a discussion paper by Navigant (the **"Navigant Paper"**)[10] which, among other things, presented arguments for and against utilization payments, as summarized in the table below:

Arguments against utilization payments	
Wholesale Price Efficiency	Real-time wholesale prices are an efficient price signal because they match supply and demand based on bids and offers on a minute-by-minute, and hour-by-hour basis, and introducing an additional payment could create an inefficacy in the market because dispatchable loads would receive an out-of-market payment that could alter their bid/offer strategy. In Ontario, this argument applies to loads that receive the wholesale energy price.
Disproportional Benefits	Providing a utilization payment compensates a DR resource disproportionately relative to a supply resource because the DR resource does not incur a cost associated with the production of electricity. Therefore, 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 the premise that the value of a megawatt of electricity curtailed (a "negawatt") is not equivalent to a megawatt of electricity, and assumes that the cost of curtailment for a DR resource is immaterial.
Harm to Other Suppliers	Utilization payments will result in downward pressure on wholesale prices because DR resources are able to bid into the energy market at prices lower than traditional supply and will be dispatched more frequently. However, in Ontario, to have a material impact on capacity or energy prices, utilization payments would have to result

[10] Attached at **Tabs "8", "9"** respectively are Navigant, *Demand Response Discussion Paper* (the "***Navigant Paper***"), dated December 18, 2017; and Navigant Demand Response Discussion Paper (Presentation to DRWG), dated November 16, 2017.

	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.
Harm to Economy	Utilization/energy payments will incentivize loads to reduce production to provide demand reductions into the electricity market, reducing the supply of other goods in the economy and increasing prices.
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
Disconnect Between Wholesale and Retail Prices	Retail prices do not 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. However, this argument is only valid for customers on retail rates and not exposed to real-time energy prices.
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. The argument is based on the FERC Order 745 which requires that the energy payments result in a *net benefit* to consumers. However, this argument is based on the assumption that, in Ontario, 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. However, 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.

54. In its conclusion, Navigant commented on the complexity of the matter and also expressed doubt on whether the benefits associated with energy payments to demand resources in other markets would apply 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 (section 3.2).

H. What was the feedback from DRWG members to the Navigant Paper?

55. The IESO encouraged DRWG members to review, ask questions and provide feedback about the Navigant Paper.[11]

56. In early 2018, the DRWG convened to continue discussion on Navigant Paper and the issue of utilization payments in the DRA.[12] The IESO responded to feedback from the DRWG members which generally fell into three categories: (1) impact on utilization; (2) fairness; and (3) market efficiency:

(a) The IESO addressed stakeholder comments that utilization payments would incentivize residential DRA participants to bid lower energy prices, which could increase utilization (p. 5). The IESO acknowledged that in

[11] Attached at **Tabs "10", "11", "12"** respectively are IESO, *Communication to DRWG Members,* dated December 19, 2017; *Utilization Payment Discussion Paper*, Demand Response Working Group (Presentation), dated January 30, 2018; and IESO, *Communication to DRWG Members*, dated February 12, 2018.

[12] Attached at **Tabs "13", "14"** respectively are *Utilization Payments Discussion*, Demand Response Working Group, dated March 1, 2018 (**"*DRWG Presentation of March 1, 2019*")**; Demand Response Working Group, *Meeting Notes – March 1, 2018*, dated April 5, 2018.

theory this could incentivize participants to lower energy bid prices, which could lead to increased utilization of DR resources. However, the IESO observed that stakeholder feedback indicated utilization payments might not lead to increased utilization.

(b) The IESO addressed stakeholder comments that under the former Capacity Based Demand Response ("**CBDR**") regime, CBDR resources were prepared to be activated at $200/MWh provided they received this payment demonstrating that revenue is a strong incentive for activation (p. 7). The IESO responded that 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. This phenomenon implied that that DR participants' value of energy consumption was much higher than this level.

(c) The IESO addressed stakeholder comments that if paying a DR resource for utilization reduces the cost of electricity, then DR payments are a positive system benefit (p. 8). The IESO acknowledged that if DR utilization payments could reduce total system costs then it would yield a positive system benefit. However, the IESO observed that on balance, it was not clear that there would be a positive system benefit. Even if providing a utilization payment might reduce the energy price of electricity for that event, other system costs such as uplift and capacity costs would increase.

(d) The IESO addressed stakeholder comments that DR utilization payments based only if "negawatts" and megawatts are functionally and economically equivalent (pp. 10- 14). The IESO provided some illustrative examples where resources could receive additional payments – creating an unequal treatment depending on the configuration of the capacity contribution.

I. Did the IESO reach any conclusions after the publication of the Navigant Paper?

57. No, the IESO did not come to any definitive conclusions on this issue. After further consultation with stakeholders, the IESO, however, did offer the following observations as part of March 1, 2018 presentation to DRWG members:

(a) It appears that the current practice for compensating DR utilization is equivalent treatment and a DR utilization payments would introduce non-equivalent treatment;

(b) There was no clear indication that utilization payments would increase activation for most load types;

(c) For resources exposed to market prices, further discussion did not appear to be merited; and

(d) For resources not exposed to market pricing, the IESO did not see merit in continuing discussion on utilization payments - however, the IESO expressed uncertainty regarding the impact of utilization payments on these type of participants and the IESO requested more input from stakeholders;

(e) Based on the quantity of stakeholder feedback received, the IESO did not see a strong interest from the DRWG on the topic of utilization payment. Only two members submitted feedback on and members declined to present their views for discussion at the DRWG.[13]

58. The issue of utilization payments for DR resources in the DRA ceased to be a priority item for the DRWG after the spring of 2018.

PART VI - THE NEED FOR THE TCA

A. Why did the IESO decide to evolve the DRA into the TCA?

59. As part of its Market Renewal initiative, the IESO had been planning an Incremental Capacity Auction (**"ICA"**) to address Ontario's future incremental capacity

[13] *DRWG Presentation of March 1, 2018*, pp. 16-18

needs. The ICA, which was to be a competitive auction open to participation by a broad range of supply and demand resources, was intended to replace the DRA. The IESO planned to launch the ICA in 2022.

60. On September 13, 2018 the IESO released an updated Electricity Planning Outlook that forecasted a capacity deficit in summer 2023 of 3844 MW (p. 51).[14] Shortly after this, the IESO came to the realization that it was not feasible to launch the ICA in time to address the projected 2023 capacity gap (the **"2023 capacity gap"**) and that alternative measures were required.

61. The IESO determined that the best solution for addressing the 2023 capacity gap was to evolve the DRA into the TCA, for reasons which included the following:

(a) the DRA was directionally aligned with the ICA in that there would be a demand curve based auction that would be executed at regular intervals for a future one-year long capacity need (with two 6-month seasonal periods);

(b) the DRA was a proven mechanism governed by an existing set of market rules;

(c) the DRA provided a platform that could be incrementally evolved into a broader-based and more competitive capacity auction, which would provide the IESO and market participants with opportunities to learn, adapt and make improvements; and

(d) a TCA was preferable to contractually procuring new capacity, which was a less flexible mechanism and risked higher costs for consumers.

62. The IESO also determined that the TCA would provide opportunities for existing off contract generators, which might otherwise decide to wind down their operations to the potential detriment of Ontario reliability and the interests of Ontario consumers. In particular, the IESO was concerned with the risk of permanently losing these existing generation facilities and not having them available when the 2023 capacity gap

[14] Attached at **Tab "15"** is a Technical *Planning Conference Presentation*, dated September 13, 2018, p. 51.

emerged, since these facilities may be able to more cost-effectively satisfy future capacity gaps compared to other alternatives, including the construction of new generation facilities. In addition, these existing resources offer an additional measure of certainty as compared to unknown future alternatives.

63. The TCA was also established to enable the future participation of capacity imports from other jurisdictions. Capacity imports are likely to play an important role in the future and the TCA would establish auctions as a credible and certain mechanism that would entice economic external resources to supply capacity to Ontario.

B. Can the IESO rely upon the DRA to fill the forecast 2023 capacity gap?

64. The IESO cannot rely upon the existing DRA to provide sufficient capacity to satisfy the 2023 capacity gap.

65. The DRA in December 2018 attracted a qualified capacity of over 1000 MW. This is insufficient to meet the 2023 capacity gap, which is now forecast at approximately 4000 MW.[15]

66. HDR resources have also had a history of poor performance during test activations. Between February 2018 and January 2019, HDR resources had a 58% failure rate for test activations which were four hours in duration.[16] 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.

67. HDR resources, which comprise the large majority of DRA participants, are also, unlike dispatchable generators or loads, not dispatchable on a five-minute basis. This presents operability and reliability challenges as compared to relying on capacity from supply or dispatchable load resources. Given the IESO's need to maintain a diverse supply mix of resources to meet system needs, both HDR and DL resources are part of the total solution in meeting Ontario's capacity needs – mixed with other resources that

[15] Attached at **Tabs "16" "17" "18"** respectively are the Stakeholder Advisory *Committee Presentation*, August 14, 2019, p.4 (**"*SAC Presentation*"**); and North American Electronic Reliability Corporation, *2018 Long-Term Reliability Assessment*, dated December 2018 (**"*NERC Report*"**); Northeast Power Coordinating Council, *2018 Ontario Comprehensive Review of Resource Adequacy* (Issue 3.0), dated December 4, 2018 ("***NPCC Report*"**).

[16] Attached at **Tab "19"** is the *Hourly Demand Response (HDR) Testing Update*, dated April 25, 2019.

can be scheduled on a 5-minute or hourly interval both inside and outside of Ontario. The IESO could not assure reliability if all the 2023 and beyond capacity came from only one resource type – diversity in fuel supply and operating characteristics are needed to maintain reliability.

C. Is the IESO still forecasting a capacity gap in summer 2023?

68. Yes, there continues to be a significant 2023 capacity gap that must be addressed by the IESO to ensure the reliability of Ontario's electricity system.

69. This gap has been recognized by the Northeast Power Coordinating Council (**"NPCC"**) and the North American Reliability Corporation ("**NERC"**),[17] with which the IESO is required to report annually on the state of reliability of Ontario's electricity system, including resource adequacy. The assessments are based on NERC and NPCC planning criteria to ensure a consistent approach to reporting and evaluation of the broader regional and continent-wide power system reliability.

70. There are inherent uncertainties with any planning projection. Ontario's extensive nuclear refurbishment and retirement schedule contributes to the capacity gaps in the near-term as the fleet is readied life-extending work or shutdown. As noted in the NERC Report, "there are uncertainties in the projections that could see the shortfall grow or shrink. As a result, the Independent Electricity Service Operator (IESO) will continue to update and refine its forecasts to gain more certainty about the size of the gap" (p. 15, *Figure 1.5*)".

71. In a presentation to the IESO's Stakeholder Advisory Committee dated August 14, 2019, the IESO provide an updated forecast of a capacity gap of approximately 4000 MW in summer 2023. [18] This is the IESO's most up-to-date forecast.

D. Why is it necessary for the IESO to proceed with a phased implementation of the TCA?

72. The introduction and implementation of the TCA, and subsequent capacity auction phases, is complex and challenging. The IESO has never before undertaken a capacity auction which includes supply resources. The IESO is accordingly initiating this

[17] See *NPCC Report; NERC Report.*
[18] *SAC Presentation*, p. 4.

process gradually and incrementally by, at the outset, only including off-contract dispatchable generation facilities. Thereafter, subsequent capacity auctions will include and add new resource types and broaden resource eligibility criteria. New resource types are anticipated to include storage, system-backed imports, resource-backed imports and self-scheduling generation facilities. Resource eligibility criteria may also be broadened to include, for example, surplus or uprated capacity (i.e. merchant capacity) at existing contracted facilities.

73. These changes will present new requirements and pose additional challenges. For instance, the addition of system-backed and resource-backed imports will necessitate negotiating operating agreements procedures with other independent system operators (**"ISOs"**) and addressing other jurisdictional issues. Likewise, rules governing the participation and compensation of imports must be tailored to reflect the unique operating features of different import types. These differences introduce complexity to the potential participation of imports in the capacity auction and energy market.

74. In addition to the introduction of new resource types and new eligibility criteria, each capacity auction phase, beginning with the TCA, will introduce modified design elements, including capacity qualification criteria, testing and audit requirements, connection assessment criteria, market power mitigation parameters, auction parameters, etc. For instance, introducing new qualifications of capacity will require the IESO to assess each resource's offering into the auction prior to the auction's execution. The intent is to better align the auction results with the IESO's system planning assumption; however, the new process may change a participant's offer strategy and ultimately the auction outcome.

75. In addition to known and foreseeable challenges, there are potential unforeseen consequences. The IESO knows from experience that major new market changes and programs invariably have unforeseen implications and consequences affecting market efficiency or reliability that will need to be addressed through market rule and market manual amendments, and possible tool changes.

76. 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 in a

single step, or closer to the eve of the 2023 capacity gap which the TCA is 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.

77. 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. The IESO, as the Province's reliability authority, is not willing to forgo the important opportunities, experience and learnings that these auctions, each with a year long commitment period, provides and which are critical to implementing a capacity auction mechanism to prudently and cost-effectively address Ontario's future capacity needs.

PART VII - THE IMPLEMENTATION OF THE TCA

A. When did the IESO announce its decision to proceed with the TCA?

78. On January 28, 2019, Peter Gregg, the president and CEO of the IESO, announced that the IESO's plan to expand the DRA to include generators in order to meet immediate resource adequacy needs in Ontario:

> This transition to a capacity auction will start to take shape later this year. As you know, in September we produced a new planning report which indicated a potential capacity gap emerging in 2023. This gap would emerge at a time when Pickering units are closing, as nuclear refurbishments are underway and as some of our generation contracts expire.
>
> While the forecasted gap is relatively small at the moment, our ability to continue to rely on existing resources such as conservation, could affect both the timing and the size of any potential gap.
>
> …[W]e expect to have a clearer picture of our more immediate capacity needs in the third quarter of this year.
>
> We will meet those capacity needs by leveraging the competitive mechanisms we have in place right now such as the annual demand response auction.
>
> […]
>
> In December, we will run an auction to meet capacity needs for 2020. Our goal is to have that auction and subsequent auctions build on the current demand response auction including allowing more resource types to compete. This would provide generators whose contracts are expiring over the next few years an opportunity to compete in our electricity market and help meet emerging capacity needs. It is a staged approach to a much more competitive marketplace … one that we at the IESO and others are striving for. It allows us to realize efficiency, competition and transparency … the key principles of our market renewal efforts – as quickly as possible.

> It's also a sensible approach, allowing both the IESO and market participants to continue to learn and improve our processes as capacity needs increase[19].

B. What stakeholder engagement did the IESO undertake on the TCA?

79. In February 2019, the DRWG convened to discuss the IESO's plan to evolve the DRA to meet Ontario's capacity needs after 2019. At this time, some DRWG members renewed their interest in DR resources receiving utilization or energy payments. The IESO agreed to further consider this issue.[20]

80. In late February 2019, the IESO initiated a stakeholder engagement to inform IESO decision-making in the design and the implementation of the TCA. The first TCA engagement session was held on March 7, 2019 and included representation from generators, consumers, DR resources and other interested stakeholders. At this meeting, the IESO introduced its "Stakeholder Engagement Plan", which set out the following objectives:

(a) understand the changes involved in the development of the TCA;

(b) understand how proposed changes to the DRA may affect stakeholders; and

(c) gather stakeholder feedback on any significant issues and potential solutions associated with the proposed design features[21] (pp. 16-19).

81. Most participants in the stakeholder engagement were generally supportive of the decision to transition the DRA to the TCA, however, some DR representatives, including AMPCO, objected to launching the TCA without first resolving the issue of energy payments for DR resources. AMPCO and other DR representatives said DR participants would be at a competitive disadvantage vis-à-vis generators in the TCA if they were not entitled to energy payments.

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[19] Attached at **Tab "20"** is *Remarks by Peter Gregg at Ontario Energy Network Luncheon*, dated January 28, 2019, pp. 8-9.

[20] Attached at **Tab "21"** is *Demand Response Working Group Meeting Notes for February 12, 2019*, dated February 12, 2019, p. 11.

[21] Attached at **Tab "22"** is *Meeting Ontario's Capacity Needs*, "Evolving the DR Auction to Transitional Capacity Auction", dated March 7, 2019.

82. The IESO advised participants in the stakeholder engagement that the IESO intended to proceed with the TCA in December 2019, which would serve as an important learning experience for the IESO and market participants in preparation for the 2023 capacity gap, including allowing for price discoverability. The IESO, however, advised stakeholders that the issue of energy payments would be further considered as part of DRWG, including prioritizing the issue as part of the 2019 DRWG Work Plan, and that the IESO would follow up on the Navigant Paper and consider a "made-in-Ontario rationale supported by a good business case" [22]

83. In May 2019, The IESO posted the draft TCA design documents and draft market rule amendments, which were thereafter discussed by stakeholders at a stakeholder engagement session on May 22, 2019.

C. How else did the IESO respond to AMPCO and other DR representatives concerns?

84. In response to AMPCO's and other DR representatives' concerned about energy payments, the IESO decided to commence a separate stakeholder engagement initiative entitled *Energy Payments for Economic Activation of Demand Response Resources* (**"*Energy Payments Stakeholder Engagement*"**). The IESO commissioned a third-party consultant, Brattle Group, to support the research and analysis and sought stakeholder feedback on the inputs and outputs of third party research and analysis to inform the IESO's decision on the energy payment issue. This engagement and the Brattle study will follow up on some of the important matters identified for further consideration in the Navigant Paper.

85. On October 10, 2019, IESO issued the proposed reference question for consideration in the Energy Payments Stakeholder Engagement – "Should demand response resources receive energy payments when they are activated in-market?" (p. 17) – followed by the proposed scope for the engagement and associated Brattle third party study:

(a) What is the relevant Ontario context and history?

[22] Attached at **Tab "23"** is *Demand Response Working Group – Meeting Notes, dated April 25, 2019*, pp. 4, 11.

(b) What are the economic first principles that drive the activation decision for demand response resources?

(c) How are in-market activations compensated in other jurisdictions and what are the key takeaways for Ontario?

(d) If compensation is provided, what could the compensation model look like in Ontario?

(e) 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?[23]

86. Stakeholders were invited to provide written feedback by October 25, 2019 on the proposed study scope which will inform the final study scope, which the IESO intends to publish in December 2019. AMPCO is participating in this engagement and provided input on the final study scope.

87. The IESO anticipates that the Brattle study will be completed by Q1 of 2020 and the IESO is targeting June 2020 for its rationale and final decision on energy payments for DR resources. The IESO will then commence the market rule amendment process for any changes that are needed to implement the decision.

88. The IESO does not have an estimated timeline as to when any necessary market rule amendments could be put in place to implement its final decision on the energy payments. The timeline would, among other things, depend on the findings of the study and the scope of implementation.

PART VIII - THE ADOPTION OF THE AMENDMENT

A. What was the recommendation of the Technical Panel on the Amendment?

89. On June 18, 2019, the proposed Amendments were submitted to the Technical Panel for review and comment. At the Technical Panel's meeting, on June 25, 2019, the Technical Panel voted to submit the proposed Amendments for stakeholder review and comment.

[23] Attached at **Tab "24"** is *Energy Payments for Economic Activations of DR Resources*, dated October 10, 2019, pp 23-24.

90. AMPCO, along with the Advanced Energy Management Alliance ("**AEMA**") submitted a joint legal brief[24] that referenced FERC Order 745 and argued that the failure to compensate DR resources with energy payments in a manner equivalent to compensation provided to generation resources for similar services is unjust and unreasonable, unjustly discriminatory, and anti-competitive. The brief further argued that there exists "no rationale for implementing the TCA prior to the resolution of the issue of just and reasonable compensation for DR resources...."

91. Following further stakeholder review and feedback, the proposed Amendments were submitted to the Technical Panel on August 6, 2019. On August 13, 2019, the Technical Panel voted 11-1 to recommend the proposed Amendments for consideration to the IESO Board.[25] Three of the four consumer representatives on the Technical Panel voted in favour of recommending the Amendment.

92. The Technical Panel recommended the Amendments for approval by the IESO Board for reasons, which included the following:

(a) more competition in the TCA, which will put downward pressure on auction clearing prices and will benefit consumers;

(b) supports the development of a reliable capacity market to address future resource adequacy needs;

(c) implementing the TCA in phases, and making changes and accommodations in the future is a helpful step to gaining experience and developing an efficient and competitive electricity market;

(d) TCA helps to ensure that the power system is adequately prepared to meet future needs by providing additional mechanisms to address capacity and energy requirements;

(e) due consideration will be given to DR resource's concerns about fair and reasonable compensation as part of the planned study;

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[24] Attached as **Tab "25"** is AEMA/AMPCO Joint Brief, "IESO Proposed Capacity Auctions and Demand Response Resource", dated July 2019.

[25] Attached as **Tab "26"** is the *Technical Panel Rationale*, dated August 13, 2019.

(f) providing energy payments to economic activations to DR resources is a wider market issue that will require more consultation has implications for the entire design of Ontario's electricity (energy and capacity) market; and it is It is not worth holding up TCA for this;

(g) the issue of energy payments for DR resources' is not-material because economic activations have historically been infrequent, and are projected to be infrequent in the future;

(h) TCA is a first step toward enabling competition to provide capacity;

(i) TCA is a prudent approach to maximizing future participation in advance of more significant capacity gap emerging; and

(j) TCA broadens participation while retaining features and functionality required for participation by HDR and dispatchable loads.

B. What were the IESO Board's reasons for adopting the Amendment?

93. As noted above, the Amendment was adopted by the IESO Board at its meeting of August 28, 2019.[26] The IESO Board provided reasons for its decision (the "**Reasons**").[27]

94. 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.

95. 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.

[26]Attached at **Tab "27"** is the Resolution of the IESO Board, dated August 28, 2019.

[27] Attached at **Tab "28"** are the Reasons of the IESO Board in Respect of an Amendment to the Market Rules, dated August 28, 2019 (the **"*Reasons*"**).

(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.

96. 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 FERC Order 745 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.

97. The IESO Board concluded that implementing the Amendment was 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." [28]

98. The IESO Board also noted that the Technical Panel recommended the Amendment in a vote of 11-1 and that in respect of a process issue related to the AEMA/AMPCO joint brief, "exercised its discretion on an informed and reasonable basis."[29]

PART IX - RESPONSE TO AMPCO'S EVIDENCE

A. What is the IESO's response to Mr. Anderson's statements about the IESO proposing that participants in the DRA include "work around" payments in their bids?

99. The IESO does not know what Mr. Anderson is referring to in this statement. It is up to a DRA participants to determine their auction bid prices, including what costs they factor into their bid prices.

B. Why does the IESO say the impact of the Amendment on DR Resources is not material?

100. As noted above, DRA participants have historically been rarely activated in the energy market because their price bids have been far excess of the HOEP.

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[28] *Reasons,* p. 4.
[29] *Ibid*, p. 5.

101. The IESO does not expect the likelihood of economic dispatch to materially increase in the commitment period under the December 2019 auction (May 1, 2020 to April 30, 2021). There has been no material change in the target capacity for the December 2019 commitment period (675 MW for summer and winter commitment periods) as compared to the December 2018 commitment period (611 MW for summer and 606 MW for winter).[30] The total target capacity is negligible in the context of total system need.

102. As a result, the IESO does not anticipate any activations of HDR resources during the December 2019 commitment period (HDR resources have constituted the significant majority of participants in the DRA). The IESO also anticipates infrequent activations of dispatchable loads during the December 2019 commitment period.

103. Given this low probability of DR resource activation, the inclusion of a work around payment should have no material impact on DR auction offers for the December 2019 commitment period.

104. In the IESO's view, there is no justifiable rationale for DR resources participating in the TCA to include any work around payments in their bids. The amount of any work around should reflect both the costs of being activated and the very low likelihood of activation. The IESO has not been presented with any economic analysis to the contrary, and, in fact, AMPCO's answers to Board staff's interrogatories confirm the IESO's views (see AMCPO's interrogatory response to Board Staff's interrogatory No. 1).

C. Would energy payments increase the likelihood of activations of DR resources under the TCA?

105. The IESO does not expect any energy payments to be material in the December 2019 commitment period. Therefore, the IESO does not expect that the availability of an energy payment would influence frequency of activations of DR resources. As Navigant states in section 3.1.5 of the Navigant Paper, "[l]arge commercial and industrial

[30] Attached as **Tab "29"** is *Demand Response Auction Pre-Auction Reports*, dated September 26, 2019.

customers with a high value of lost load are not likely to change their bids into the energy market because of utilization payments".[31]

D. Does the IESO have a view on the applicability of FERC "net benefit test" in Ontario?

106. No. This is a complex issue, which as noted by Navigant, has to consider the unique aspects of the Ontario market. The IESO has not yet made a final decision on the appropriateness and outcome of the net benefits test in Ontario, which is why the IESO is in the process of engaging with stakeholders and studying this issue as part of the Energy Payments Stakeholder Engagement.

107. That said, the only Ontario-specific analysis available is from Navigant who concluded that "more DR activations (as a result of bidding into the market at prices lower than traditional generators) would not actually lead to reduced cost to consumers since generators have their compensation guaranteed."[32] In other words, any reductions in the IESO market price may simply be offset by out of market Global Adjustment payments.

E. Will the IESO consider energy payments for DR resources?

108. Yes. While DR resources will not be entitled to receive energy payments if activated under the TCA during the December 2019 commitment period, the IESO has not made a final determination on the issue and will not do so until the conclusion of the Energy Payments Stakeholder Engagement. Following the conclusion of this engagement and issuance of the Brattle study, the IESO will make a final determination, including initiating any necessary market rule amendments to provide for energy payments to DR resources.

F. Why won't the IESO delay the TCA until it has resolved the issue of energy payments for DR resources?

109. In summary and as stated above:

[31] *Navigant Paper*, at 3.1.5

[32] *Navigant Paper*, at 3.2.

(a) It is the IESO's judgment as the province's reliability and planning authority that it is prudent to proceed now with the TCA in an incremental and phased manner and that there are real reliability and cost risks to delaying and not proceeding in this manner. These risks include losing the opportunities for the IESO and TCA participants to learn and adapt from a series of TCA auctions, as well as risking the loss of existing off contract generation facilities that may be important and cost-effective for the purpose of addressing the 2023 capacity gap in future capacity needs.

(b) AMPCO does not object to the TCA. It objects to commencing the TCA without changing the market rules to provide for energy payments to loads. This would be a major change to Ontario's electricity market design and it is the IESO's opinion that this sort of fundamental change should not be made without broad consultation and necessary study and analysis. FERC Order 745 is a relevant consideration but it is not binding in Ontario and, as the Navigant Paper makes clear, there are differences in Ontario's hybrid market and there are real doubts as to whether energy payments to DR resources would result in net benefits as conceived by FERC. This is why the IESO is undertaking the current stakeholder engagement on energy payments and third-party study, which the IESO is prioritizing and will result in an IESO final recommendation by the end of Q2 2020.

(c) AMPCO's members' interests are not determinative. The IESO, in accordance with its statutory mandate, must consider system reliability and the broader interests of other market participants and consumers. These considerations, as noted, weigh heavily in favour of proceeding with the TCA without delay. That being said, even if the IESO were to more narrowly focus on the interests of AMPCO members and other DR resources, there is no evidence that they will be materially harmed by proceeding with the TCA. The IESO has not seen any evidence from AMPCO that its members or other DR participants will be harmed. Moreover, AMPCO's assertions that DR participants will be competitively disadvantaged in the TCA auction is contradicted by the fact that DR resources have rarely been activated in the energy market and the IESO does not anticipate any material change in this respect over the December 2019 TCA commitment period.

* *

TAB 1

Menu

Sector Participants > Engagement Initiatives > Overview > Engagement Principles

Overview

Engagement principles guide the conduct of the IESO, market participants, stakeholders, communities, customers and the general public towards an efficient and effective process. Initiatives require different forums for engagement and all are posted the IESO website. The IESO uses the perspectives brought forward in these forums to inform its decision making.

IN THIS SECTION...

Upcoming Events

Electricity Summit

Engagement Principles

Public Information Sessions

Customer Readiness - IT System Changes

Engagement Principles

Engagement principles guide the conduct of both the IESO and the public to help ensure the engagement is conducted with integrity towards an efficient and effective process. The public, for these purposes, refers to market participants, stakeholders, communities, First Nations and Metis Peoples, customers and the general public.

The IESO uses the perspectives brought forward to inform its decision-making. Responsibility for decisions rests with the IESO. Regional planning engagements will also adhere to the recommendations set out in the 2013 Planning & Siting Report. The IESO will use these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

1. **Analyze Opportunities for Engagement**
   The IESO, often through discussions with the public, will identify opportunities, changes and issues and their potential impacts. The engagement process will accommodate a range of approaches to reflect the nature and importance of the initiative and the expected level of participation. The IESO will involve others early as opportunities are identified and will document a process to achieve the desired goal of the engagement.

2. **Ensure Inclusive and Adequate Representation**
   Efforts will be made to assess the interest level and impacts for each initiative or decision-making process and will encourage effective representation of the public in each engagement, especially those groups that have a tendency to remain silent or reluctant to engage. Where practical, a variety of engagement methods will be offered to provide flexibility to participate.

3. **Provide Effective Communication and Information**
   The IESO will facilitate a process that provides relevant, accurate and timely information needed for meaningful participation and that provides adequate time for review and consideration. The IESO will make best efforts to provide information as early as possible and will present it in a manner that can be readily understood. Two-way dialogue will be encouraged throughout an engagement.

4. **Promote Openness and Transparency**
   Openness and transparency will be assured throughout the process in a way that allows for inclusive participation of all affected. The IESO will plan each engagement initiative, set objectives and timelines, track and document the process and report on progress. On occasions when the IESO has a position on a particular initiative it will openly share those perspectives while remaining open to feedback. Through each initiative, the IESO will remain open to consider input that can influence recommendations and decisions. The IESO will ensure that it communicates how advice, input and feedback is being used.

5. **Provide Effective Facilitation**
   The IESO, as facilitator, will provide a forum that encourages a diversity of views to be presented and will respect and understand those views through meaningful, respectful dialogue that incorporates listening and honesty.

6. **Communicate Outcomes**
   The IESO will communicate decisions, the rationale for the decision and how input was taken into account in the decision. Input received will be communicated to decision makers prior to decisions being made. The IESO will also work with those impacted when implementing changes.

7. **Measure Satisfaction**
   The IESO will survey those who have been involved in engagements at least one time per year to test its adherence to these Principles and to determine satisfaction with the process.

TAB 2

Ontario Energy Board   Commission de l'énergie de l'Ontario

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2015 – April 2016

May 2017

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Role of the Market Surveillance Panel

The Market Surveillance Panel (Panel) is a panel of the Ontario Energy Board. Its role is to monitor, investigate and report on activities related to – and behaviour in – the wholesale electricity markets administered by the Independent Electricity System Operator (IESO).

The Panel monitors, evaluates and analyzes activities related to the IESO-administered markets and the conduct of market participants to identify:

- inappropriate or anomalous conduct in the markets, including gaming and the abuse of market power;
- activities of the IESO that may have an impact on market efficiencies or effective competition;
- actual or potential design or other flaws and inefficiencies in market rules and procedures; and
- actual or potential design or other flaws in the overall structure of the IESO-administered markets and assess consistency of that structure with the efficient and fair operation of a competitive market.

Market-related activities and market conduct may also be the subject of a more formal and targeted investigation by the Panel. To that end, the Panel has authority under the *Electricity Act, 1998* to compel testimony and the production of information.

The Panel reports on the results of its monitoring and investigations, making recommendations for remedial action as it considers appropriate.

Executive Summary

Market Overview and Developments

In Chapter 1 the Panel provides its general assessment of the state of the IESO-administered markets, including their efficiency and competitiveness. Given some of the limiting features of Ontario's hybrid market design, competitive market forces play a greatly diminished role relative to what was originally envisioned, as well as relative to other North American jurisdictions. There remain significant opportunities to unlock competition and drive more efficient production, delivery, consumption and investment decisions.

To that end, the Independent Electricity System Operator (IESO) launched the Market Renewal stakeholder engagement in March 2016. Engagement participants and the IESO are critically examining the foundations of Ontario's electricity market; in doing so, identifying current market design issues and considering fundamental changes.

The Panel strongly supports the IESO exploring market design alternatives and will continue to support the initiative through its participation in the Market Renewal stakeholder initiatives.

In addition to Market Renewal, the Panel provides brief updates on a number of IESO and broader industry initiatives, including: the expansion of the Industrial Conservation Initiative, Ontario's energy trade deal with Québec, the Province's Greenhouse Gas Cap and Trade program and the IESO's capacity export initiative.

In the Panel's November 2016 Monitoring Report it made two recommendations related to the Real-Time Generation Cost Guarantee (RT-GCG) program. In addition, the Panel made three submissions to the IESO's *RT-GCG Program Cost Recovery Framework* stakeholder engagement. In each case, the Panel stated its concern with the cost of the RT-GCG program, as well as its uncertain benefits. The Panel's own analysis demonstrated that the program was necessary less than 1% of the time it was used.

The IESO has yet to address these concerns in a meaningful way.

The Panel believes that a new approach is needed that balances the competing priorities of reliability and cost and ensures that decisions are supported by objective analysis that considers whether lower cost alternatives are feasible. To guard against a "reliability at all costs" approach, other jurisdictions have developed objective and open processes for assessing these competing priorities. A similar approach should be considered in Ontario.

Matters to Report in the Ontario Electricity Marketplace

Assessment of the IESO's Demand Response Auction

Since 2004, the Government of Ontario has been mandating the development of electricity conservation programs. The primary aim of these programs is to alleviate the need to build new generation facilities by reducing demand during peak periods. Demand Response (DR) programs, which incent consumers to reduce consumption during periods of high prices, high demand or tight supply, have been a large part of that conservation effort.

The IESO is responsible for achieving the conservation related policy goals set forth by the Ministry of Energy. Prior to 2015, bilateral contracting was the primary means of procuring the necessary DR resources to meet policy objectives; in 2015, the IESO developed the DR auction. The DR auction introduced a competitive, flexible and transparent process for procuring DR resources, where formerly there was none. DR resources procured in the 2016 and 2017 DR auctions will be paid up to a total of $73 million; these payments are recovered from Ontario consumers by uplift charges.

The resources procured through the DR auction are intended to help meet the Ministry of Energy's conservation policy goals. However, for the reasons explained in detail in Chapter 4 of this Report, it is unlikely that the current DR program will actually contribute to conservation or demand reduction. Briefly, this is because the rules associated with the DR auction establish thresholds for activation which have not been realized to date and are unlikely to be realized in the future.

Having said that, the Panel also questions the need for peak shaving DR capacity at this time as Ontario has sufficient resources to meet peak demand in the province for the foreseeable future.

Recommendation 4-2:

The IESO should reassess the value provided by the capacity procured through its Demand Response auction in light of Ontario's surplus capacity conditions, as well as the stated

preference of the government and the IESO (through its Market Renewal initiative) for technology-neutral procurement at least cost.

Improving the Allocation of Disbursements from the Transmission Rights Clearing Account

When an intertie becomes congested, the price used to settle intertie transactions can differ from the province-wide Market Clearing Price (MCP). This produces a situation in which either side of the same transaction is settled at different prices: the intertie transaction is settled at the intertie price, while the corresponding domestic transaction is settled at the MCP. The difference in the money collected from the buyer and paid to the seller is referred to as congestion rent. Congestion rent reflects the value of scarce transmission capacity. The more valuable access to a transmission path is to those who wish to utilize it, the higher the congestion rent collected.

Given intertie traders are willing to pay for scarce transmission capacity in the form of congestion rent, it follows that the owner of transmission capacity would benefit from making that transmission capacity available. In Ontario, the companies that own transmission capacity are rate regulated. Any congestion rent revenue these companies receive would go to offset their revenue requirements, thus reducing the regulated rates charged to their transmission customers. It follows that transmission customers benefit from congestion rent.

Congestion introduces financial risk to intertie traders. In order to provide the opportunity to hedge against that risk, the IESO operates a Transmission Rights (TR) market. TRs provide a financial hedge against price differences between the intertie price and the MCP. TR payments are designed as a full hedge against paying congestion rents; accordingly, TR payments and congestion rents collected should be approximately equal. By purchasing a TR, the owner has essentially purchased the right to the congestion rents on that intertie.

In return for relinquishing congestion rents, transmission customers receive the proceeds generated from the sale of TRs; these proceeds are known as “auction revenues”. Auction revenues accrue in the TR Clearing Account and are periodically disbursed to transmission customers to offset the transmission charges they pay. The manner in which these funds are disbursed has no impact on market efficiency or reliability, therefore the Panel looked to its other mandated principle, namely fairness, to assess the appropriateness of the existing methodology.

Considering that disbursements are intended to offset transmission charges, they are effectively a rebate on costs paid. The Panel believes that a fair allocation would have each customer receive a rebate proportionate to its share of costs paid. Unfortunately the current allocation methodology has not resulted in what the Panel considers to be a fair allocation of disbursements. Ontario transmission customers have paid in excess of 98% of all transmission charges, but received only 86% of disbursements; exporters received 14% of disbursements despite paying less than 2% of total transmission charges.

This misalignment stems from the fact that disbursements are allocated based on each customer's share of demand over the previous months, not its share of transmission service charges paid. The transmission charge associated with a megawatt-hour of Ontario based demand is significantly higher than the transmission charge associated with a megawatt-hour of export demand. As a result, exporters benefit disproportionately when disbursements are based on demand.

To date, the IESO has disbursed $58 million from the TR Clearing Account to exporters, $51 million of which the Panel believes ought to have been paid to Ontario transmission customers. Given the ongoing and material nature of this issue, future transfers will be significant if the current disbursement allocation methodology is left unremedied.

Recommendation 4-1

A. ***The IESO should revise the manner in which it allocates disbursements from the Transmission Rights Clearing Account such that disbursements are proportionate to transmission service charges paid over the relevant accrual period.***
B. ***The IESO should not disburse any further funds from the Transmission Rights Clearing Account until such time that Recommendation 4-1(A) has been addressed.***

Market Outcomes and Anomalous Events

The Panel's review and analysis of market outcomes covers the period from November 2015 to April 2016 (the Current Reporting Period). The Panel's analysis revealed the following items of interest.

Dispatchable Loads and Unavailable Operating Reserves

Operating Reserve (OR) is standby capacity intended to respond and recover from a contingency on the grid, such as a forced generator or transmission outage. A dispatchable load (DL) may provide OR standby capacity; when it is activated to help recover from a contingency, the DL provides relief by reducing its consumption. To be able to provide the required relief (and fulfill its OR activation), a DL must be consuming at least the activation amount prior to being activated.

In Chapter 3, the Panel examines an hour in which two DLs got paid for OR they were technically incapable of providing. These resources were compensated $25,760 for 29 MWh of standby capacity, despite not consuming sufficient electricity to provide that OR if called upon. This outcome is inappropriate: not only were the DLs potentially compromising the reliability of the grid by operating in a manner which rendered them unable to meet their OR obligation, but they were compensated for such behaviour.

This unavailable OR issue is much larger than the aforementioned example: from January 2010 to April 2016, the Panel estimates that DLs received approximately $12.5 million in OR payments for reserves that they were incapable of providing. DLs scheduled for ten-minute OR were capable of providing the entirety of their OR schedule in only 9.6% of all intervals during the Current Reporting Period.

Recommendation 3-1

The IESO should take steps to ensure that dispatchable loads are only compensated for the amount of operating reserve they were capable of providing in real-time. More fundamentally, the IESO should explore options for ensuring unavailable OR is not scheduled in the first instance.

Ramp-Down CMSC Payments and Market Rule Implementation Constraints

A generator signals its intent to come offline at the end of its run by raising its energy offer price above the local nodal price, thus becoming uneconomic in the constrained sequence. Due to the three-times ramp rate assumption used in the unconstrained sequence, a generator's unconstrained schedule ramps down faster than its constrained schedule. As a result, there is a divergence between the two schedules during the ramp-down period, resulting in constrained-on

Congestion Management Settlement Credit (CMSC) payments. In Chapter 3, the Panel examines one such payment to a gas-fired generator, totalling $160,000 over the course of one hour.

In past reports, the Panel has highlighted the inappropriate nature of CMSC payments caused by ramping, and recommended that the IESO eliminate them; CMSC is not intended to provide a revenue stream for generators that take a voluntary action.

In response to the Panel's concerns, the IESO recommended and its Board of Directors approved a Market Rule amendment to mitigate the cost of CMSC payments caused by ramping. This amendment was approved in June 2015 contingent on implementation of necessary IT system changes. Due to the complexity of these changes, they were not implemented until December 2016. The Panel estimates that CMSC payments caused by ramping would have been reduced by $1.9 million had the rule changes been effective immediately upon approval. In the future, the Panel suggests that the IESO consider providing for retrospective application of such changes to the date they are approved.

Export Failures and Congestion Rent Shortfalls

When an intertie is congested and a transaction fails following the final pre-dispatch run, the congestion rent collected may not be sufficient to cover the TR payments made, resulting in congestion rent shortfall.[1] Congestion rent shortfall results in a transfer of funds from Ontario consumers to TR owners, who are often intertie traders themselves.

When an intertie trader fails a transaction for reasons within its control (such as failing to acquire the proper transmission), it may be levied an intertie failure charge. The current intertie failure charge fails to account for the congestion rent shortfall created by the failure, leaving Ontario consumers to pay for the shortfall. This outcome is clearly inappropriate.

In Chapter 3, the Panel examines a day in which an intertie trader failed 7,456 MWh worth of exports, all for reasons within its control. For these failures, the intertie trader was charged a $466 intertie failure charge, despite causing over $12,000 in congestion rent shortfalls. This same

[1] For a quick overview of congestion rent and TRs, see the *Improving the Allocation of Disbursements from the Transmission Rights Clearing Account* section of the Executive Summary.

intertie trader profited from these intentional failures due to the TRs it owned, netting over $14,000 in TR payments.

The congestion rent shortfall issue is much larger than the aforementioned example: from January 2010 to April 2016, the Panel estimates that intertie failures within the control of market participants have resulted in congestion rent shortfalls of approximately $11 million.

Recommendation 3-2:

The IESO should revise the methodology used to set the intertie failure charge to include the congestion rents that an intertie trader avoids when it fails a scheduled transaction for reasons within its control.

Demand and Supply Conditions

Due to the mild winter weather, demand was down for all months of the Current Reporting Period relative to the same months from the previous year.

On the supply side, approximately 550 MW of nameplate generating capacity was added to the IESO-controlled grid during the Current Reporting Period. The new generating stations were all from renewable fuel sources, including 400 MW of wind capacity and 100 MW of solar capacity. Over the same period, 130 MW of distribution connected generating capacity was added, the majority of which was solar generation.

Market Prices and Effective Electricity Prices

The average Hourly Ontario Energy Price was less than $10/MWh during the Current Reporting Period, the lowest average of any six month period since market opening. Approximately one third of all hours during the Current Reporting Period experienced a price of $0/MWh or less.

Despite the low market prices, the average effective electricity price remained stable at $60.07/MWh for Direct Class A consumers, and increased $7.48/MWh to $112.25/MWh for Class B and Embedded Class A consumers. The higher average effective electricity prices for Class B and Embedded Class A consumers reflects an increase in Global Adjustment (GA) payments made to contracted and regulated resources. In January 2016 monthly total system costs, which reflects the effective electricity prices paid by all classes of consumers combined, reached an all-time high of just over $1.2 billion.

Chapter 1: Market Overview and Developments

1 *General Assessment*

Once annually, the Panel is required to provide a general assessment of the state of the IESO-administered markets, including their efficiency and competitiveness.

Since market opening in 2002, and particularly since the advent of the hybrid market in 2005, the Panel has assessed the state of the markets with regard to several design features and policy decisions that affect market participant behaviour and market outcomes. As noted frequently in past Panel reports, these features include:

- Ontario's two-schedule pricing and dispatch system: under this system, the prices faced by wholesale market participants can diverge (sometimes significantly) from the incremental cost of supplying another megawatt of energy at a particular location.
- Investment decisions are not driven by market dynamics: virtually all generation in Ontario is subject to long-term contracts with government agencies, or rate regulation by the Ontario Energy Board. Additionally, incentives under the contracts and regulation can result in offer prices that deviate from the generators' short-run marginal cost.
- The 3-times ramp rate multiplier: the use of the multiplier in the unconstrained sequence artificially depresses the market clearing price and distorts production and consumption decisions.

At market opening, some of the aforementioned features and impacts were expected to be temporary, while others were never envisioned at all; all have persisted over a number of years. The Panel has a long history of reporting on the systemic issues associated with these features, including: extended periods of deeply negative prices, inefficient trade on the interties and inappropriate wealth transfers.

Though the Panel has been critical of these features, it recognized them as ingrained parts of the current market design. In that context, the Panel's past assessments of the competitiveness and efficiency of the IESO-administered markets have been made with regard to the inherent limitations created by those features. In other words, the Panel made its assessments "within the Ontario context". On that limited basis, the Panel has said that the IESO-administered markets operated in a reasonably satisfactory manner.

Stepping out of the Ontario context, it is clear that competitive market forces play a greatly diminished role relative to what was originally envisioned, as well as relative to other North American jurisdictions. There remain significant avenues to unlock competition and drive more efficient production, consumption and investment decisions.

The IESO acknowledges the deficiencies in the current system and recognizes the benefits that market reform could bring to the sector. To that end, the IESO launched the Market Renewal stakeholder engagement in March 2016. Engagement participants and the IESO are critically examining the foundations of Ontario's electricity market; in doing so, identifying current market design issues and considering fundamental changes.

The IESO's Market Renewal initiative represents a significant opportunity to address many of the issues identified by the Panel over the years. Broad market reform has the potential to foster competition in existing markets, while introducing new competitive markets and mechanisms; all with the goal of improving efficiency. Market reform may include: the replacement of the two-schedule system with locational marginal pricing, a financially binding day-ahead market, unit commitment using multi-hour optimization, more frequent intertie scheduling and competitive procurement through technology neutral capacity auctions.

The Panel strongly supports the IESO exploring these market design alternatives and will continue to support the initiative through its participation in the Market Renewal stakeholder engagement process.

While important change is on the horizon, both the Panel and IESO recognize the long timelines associated with implementing Market Renewal. Between now and the completion of the initiative, the Panel will continue to identify deficiencies in the current market design and market rules that impact the efficient and fair operation of competitive markets. In cases where the impacts are too costly to go unaddressed until Market Renewal, or where Market Renewal will not address the issue, the Panel will continue to recommend expeditious changes, as it has done in this report.

2 *Future Development of the Market*

The IESO is currently undertaking a number of significant initiatives; they are discussed in the sections that follow.

Market Renewal

As discussed in the *General Assessment* section above, the IESO launched its Market Renewal stakeholder engagement initiative in March 2016. This initiative allows the IESO and stakeholders to address known challenges with the existing market design, and create a foundation for a more dynamic energy market to meet future needs.

The initiative will consider fundamental design changes in three categories: energy production and scheduling, capacity and operability. Specifically, the IESO has proposed the following projects in the Market Renewal work plan:

- Two schedule replacement - moving to a pricing approach reflective of actual costs
- Day-ahead market - introducing a day-ahead market to provide greater certainty to market participants and the IESO
- Real-time unit commitment - improving real-time unit commitment to optimize supply and demand over multiple hours with known costs
- Interties - enhancing intertie scheduling to improve efficiency and flexibility
- Demand response auction – establishing a workable and useful demand response auction
- Capacity trade - develop a system to enable the sale of capacity to other jurisdictions
- Capacity auction - develop an auction for incremental capacity needs.

In pursuit of these proposed changes, the IESO has retained the Brattle Group to complete a benefits case for Market Renewal. In the interim, the IESO presented the preliminary findings of its benefits case at its December 19, 2016 stakeholder engagement meeting. The preliminary findings suggest that the efficiency benefits of Market Renewal would be significant: approximately $3.7 billion from 2021 through 2030; with consumers benefitting $3.1 billion. These benefits far exceed expected implementation costs of $155 million. The final report summarizing the findings of the benefits case is expected to be published by the end of Q1 2017.

Expansion of the Industrial Conservation Initiative

On January 1, 2017 the Ontario Government expanded the Industrial Conservation Initiative (ICI) to allow customers with peak demand exceeding 1 MW to opt into the program. When introduced in 2010, only customers with peak demand greater than 5 MW were eligible to participate; the eligibility criteria was first reduced to 3 MW in 2015.

ICI customers' share of Global Adjustment charges varies based on their consumption during the five coincident peak demand hours during a year. The expansion of the ICI program will most likely mean higher Global Adjustment charges for lower volume customers, as more ICI customers shift consumption to avoid Global Adjustment charges.

Energy Trade Agreement with Québec

The provincial governments of Ontario and Québec recently signed a seven year energy trade agreement running from 2017 through 2023.[2] The general structure of the agreement includes the following elements:

- Québec will provide Ontario with 2 TWh of electricity each year,
- Ontario will reserve 500 MW of generating capacity to meet Québec's winter peak demand, and
- Ontario may provide electricity to Québec during times of surplus, part of which gets returned to Ontario during non-surplus hours.

The Panel will monitor for the impacts of the agreement on trade flows and efficiency in Ontario's wholesale electricity market.

Greenhouse Gas Cap and Trade Program

Effective January 1, 2017, greenhouse gas emitters from the energy sector are subject to the Government of Ontario's new cap and trade program. Participants in the program must have enough emission allowances to cover their emissions by the end of each compliance period. Emission allowances can be purchased at one of the quarterly auctions, or on the secondary market.[3]

Among Ontario's greenhouse gas emitters is its fleet of natural gas-fired generators. Unlike most emitters under the program, natural gas-fired generators supplied by an Ontario Energy Board (OEB) regulated gas distributor will not be obligated to acquire emissions allowances directly. Instead, the natural gas distributor will be responsible for acquiring the necessary emission allowances and complying with the program. The cost of purchasing the allowances will be

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[2] For more information see the Government of Ontario's backgrounder, available at: https://news.ontario.ca/opo/en/2016/10/agreement-between-the-government-of-ontario-and-the-gouvernement-du-quebec-concerning-electricity html

[3] For an overview of Ontario's greenhouse gas cap and trade program, see the Government of Ontario's webpage, available at: https://www.ontario.ca/page/cap-and-trade-ontario. Ontario Regulation 144/16, which passed the cap and trade program into law, is available at: https://www.ontario.ca/laws/regulation/r16144?_ga=1.105770058.816112800.1484255410

passed along to the emitters themselves, the natural gas-fired generators, in the form of a volumetric charge on natural gas purchased.[4]

The Panel expects this new volumetric charge to be included in the incremental energy offers of natural gas-fired generators. It follows that, when one of these generators is the marginal unit setting the Market Clearing Price (which was the case 19% of the time in 2016), the price will be higher. An increase in the MCP will have numerous impacts throughout the market, most notably on intertie flows and the proportion of the all-in cost of electricity recovered through the market versus the Global Adjustment.[5]

Imports from jurisdictions that typically have greenhouse gas emitting technologies on the margin are now subject to the cap and trade program. Importers will need to purchase emission allowances based on the quantity of imports and the Default Emission Factor (DEF) that applies to the source jurisdiction. Jurisdictions with heavily emitting supply mixes face higher DEFs and therefore must purchase more allowances for the same import quantity. To that end, imports from PJM, NYISO, ISO-NE and MISO will be subject to positive DEFs, while imports from Manitoba and Québec, which are primarily backed by hydroelectric generation, will not.[6] This has the effect of decreasing the competitiveness of imports from high emitting jurisdictions, while increasing the competitiveness of imports from cleaner ones.

The Panel will continue to monitor for the impacts of the cap and trade program on Ontario's wholesale electricity market.

Capacity Exports

In February 2015 the IESO launched its *Capacity Exports* stakeholder engagement to investigate the potential for allowing Ontario generators to export their capacity to other jurisdictions.[7]

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[4] See the OEB's *Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities* report, page 30, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2015-0363/Report_Cap_and_Trade_Framework_20160926.pdf

[5] Generally, the MCP and the Global Adjustment are inversely related, meaning when one increases the other tends to decrease, and vice versa.

[6] The DEFs are posted on the Government of Ontario's webpage, available at: http://www.energy.gov.on.ca/en/ontarios-electricity-system/climate-change/

[7] For more information see the IESO's *Capacity Exports* stakeholder engagement webpage, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/engagements/capacity-exports

By facilitating the export of generating capacity that is not needed for reliability in Ontario, the IESO is providing an opportunity for participants to monetize capacity that would otherwise go idle or decommission. This additional revenue stream for generators could also benefit Ontario consumers: if the exporting generator has an Ontario supply contract or is subject to rate regulation, some of the additional capacity revenues would go to offset payments under those frameworks.

As part of the engagement process, market participants were asked to contact the IESO to discuss specific export opportunities of interest. While there was general interest in capacity export opportunities to New York and Québec, only one stakeholder expressed a strong interest in pursuing a specific near term project, and demonstrated readiness. The IESO successfully implemented the necessary procedures and agreements, allowing the aforementioned market participant to offer its capacity into the New York 2016-2017 winter capacity auction.

In the longer term, the IESO intends to incorporate the capacity export initiative in to Market Renewal. In doing so, the IESO is looking to evolve capacity export opportunities by adding additional export markets, automating the participation process and integrating capacity exports into the planned incremental capacity auction in Ontario.

3 *IESO Responses to Most Recent Panel Recommendations*

Recommendation	IESO Response
Recommendation 2-1 *Given the number of recent changes in the operating reserve market, the Panel recommends that the IESO review whether the real-time operating reserve prices transparently reflect the value of operating reserve as more Control Action Operating Reserve capacity is scheduled, and whether changes to Control Action Operating Reserve offer quantities and prices could enhance the efficiency of the operating reserve market.*	The IESO will undertake the recommended review in the new year to assess the issues with the current CAOR structure and identify potential options. I anticipate that IESO staff will complete the review and report back to the MSP by late Q1 2017.

Recommendation	IESO Response
Recommendation 3-1 *The Panel recommends that the IESO eliminate from the Real-time Generation Cost Guarantee program the guarantee associated with:* *a) incremental operating costs for start-up and ramp to minimum loading point; and* *b) incremental maintenance costs for start-up and ramp to minimum loading point.* **Recommendation 3-2** *The Panel recommends that the IESO modify the Real-time Generation Cost Guarantee program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any net energy and operating reserve revenues earned, as well as all Congestion Management Settlement Credit payments received, on:* *a) output above a generation facility's minimum loading point during its minimum generation block run time (MGBRT), and* *b) output generated after the end of the facility's MGBRT.*	Background Mandatory North American reliability standards require that the IESO's daily Operating Plan demonstrate that adequate resources will be available to meet the expected load plus operating reserve. The RT-GCG program is a key element of the mechanisms that the IESO relies on in developing its daily Operating Plan and preparing for reliable real-time operations. In particular, the RT-GCG program helps meet daily reliability requirements by incenting participants to start their facilities, be available and offer real-time supply to the market. The incentive is available for generation facilities that meet eligibility criteria to ensure recovery of certain incremental start-up costs, subject to defined revenue offsets. As noted, the primary goal of the IESO's RT-GCG program is to ensure that generators are available when needed. The IESO is concerned that the Panel's recommendations, which would significantly reduce the incentive structure under the program, could have negative impacts on the program's overall reliability goals, in that the output from some gas-fired units might not be offered into the market in real time, which would, in turn, impact market dynamics and reliability, potentially impairing the IESO's ability to address changing conditions over the day. The Panel's recommendation to eliminate guarantees under the RT-GCG program for incremental operating and maintenance costs is based in part on earlier versions of the program where eligible payments were limited to fuel-only costs. However, at the time those earlier versions relied heavily on flexible generation to provide the vast majority of the starts under the program (about 80% of starts - of which over half were coal). By 2009, coal fired generation was being replaced by natural gas-fired generation facilities, which have very different operating characteristics and risk profiles. This change in the underlying characteristics of the supply mix was amongst the factors that prompted the IESO to make changes to the RT-GCG program, to include the guarantee of certain start-up operating and maintenance (O&M) costs, impose more stringent program eligibility criteria, and place limitations on eligible fuel costs - all aimed at improving the overall efficiency of the commitments. Proposed Improvements to the Commitment Process Given our concerns regarding the potential impact of the MSP recommendations, the IESO is proposing interim adjustments to the processes around unit commitments pending the market renewal initiative outlined below. These proposed changes would ensure that resources scheduled to provide Operating Reserve (OR) in the day-ahead timeframe continue to offer this OR in real-time. Currently some resources that are anticipated to provide OR based on day-ahead optimization withdraw their offers for OR closer to real-time. This

	results in the IESO having to commit additional units in real time, many under the RT-GCG, to meet OR requirements. Introducing a mechanism to maintain scheduled OR offers from Day-Ahead into real-time should result in resources with limited real-time OR capability reducing the quantity they offer into the DACP, giving more confidence that the remaining quantities will in fact be available in real-time. This should result in the necessary units needed for OR to be committed more efficiently through the DACP, instead of through the RT-GCG Program. At the same time, the changes proposed in the current RT-GCG Cost Recovery Framework stakeholder engagement initiative will limit the initial O&M payments referenced in the Panel report by introducing pre-approved cost values that will ensure greater clarity and transparency in the recovery of eligible costs, and reduce the need for time consuming after-the-fact audits and recovery of ineligible costs. To date, these recoveries have amounted to about 25% of the initial amounts claimed under the program. The IESO expects that the proposed interim improvements to the commitment process can be implemented in 2017, recognizing that they will need to be formally reviewed under the IESO's stakeholder engagement processes. <u>Market Renewal</u> The MSP work, both on GCG and other issues, has driven increased focus on the need for market renewal. Simply put, the market design developed in the early 2000's needs to be modernized to support the very different technologies, services and participants in our fast-changing sector. Accordingly, in considering the balance between investing key resources in our current market (for example in working through major changes to programs such as GCG) or in renewing our market design to meet pressing current and future needs, our market renewal program is being given priority. The Market Renewal Program will introduce fundamental changes to the energy market, including a re-design of its real-time unit commitment process to achieve reliability objectives in a more efficient manner. Consistent with the feedback that the IESO received from the Panel, all the energy initiatives (Single Schedule, Day-Ahead Market and enhanced real-time unit commitment process) will be undertaken as a single cohesive project rather than as sequenced projects, as originally proposed. That approach will ensure earlier implementation of all components. Market renewal will be a significant project for the sector and we are looking forward to working with the MSP as it proceeds.

4 *Panel Commentary on IESO Response*

The IESO's response to the Panel's concerns about the cost and uncertain benefits of the RT-GCG program largely ignores the substance of those concerns. This is consistent with the IESO's reaction to the Panel's previous recommendations and its submissions to the IESO's recent stakeholder engagement on this subject. The IESO has largely adopted a "reliability at any cost" approach notwithstanding that the Panel's own analysis demonstrated that the program was actually needed in less than 1% of the time it was used.

The Panel continues to believe that an objective and rigorous cost/benefit analysis that considers the feasibility of less costly alternatives is required.

Other jurisdictions have developed processes for assessing the competing priorities of reliability and cost.[8] The Panel believes a similar approach should be considered in Ontario.

The IESO has proposed interim adjustments to the scheduling of operating reserve that could, if adopted, reduce the number of RT-GCG commitments. This would be a positive step. However, it does not account for the fact that RT-GCG commitments are largely driven by export demand, not operating reserve requirements.

Recommendation from the Panel's February 2015 Investigation Report

In late August 2010, the IESO passed an Urgent Market Rule Amendment to suspend all Congestion Management Settlement Credit (CMSC) payments to constrained-off dispatchable loads. These CMSC payments were suspended because significant amounts had been paid to two dispatchable loads; payments the IESO believed to be inconsistent with the intent of the CMSC regime. Following stakeholder consultation, the suspension of these payments was lifted, replaced by targeted Market Rules that withheld CMSC when specific behaviours were observed.

[8] A recent example involves the National Electricity Market in Australia where, following a period of unprecedented power disruptions in the state of South Australia, including a state-wide blackout, the South Australian government proposed market rule changes to enhance reliability. The Australian Energy Market Commission, the agency responsible for making rule changes, recognized that the proposed reliability enhancements will support security of supply for consumers but that they must also be delivered at the lowest possible cost. Even with the sector in a state of heightened concern over reliable supply, the passing of the proposed reliability enhancements remain subject to a robust cost benefit process. See: http://www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen#

In the course of its investigation into the possible gaming behaviour of the two aforementioned dispatchable loads, the Panel observed that despite the new Market Rules, significant CMSC continued to be paid.[9] The Panel recommended that the IESO review the CMSC payments being made to dispatchable loads, and if necessary, make further amendments to eliminate unwarranted CMSC payments.

The IESO conducted the recommended review and found what the Panel considers to be a material amount of unwarranted CMSC still being paid. While the IESO believes it has the appropriate authority under the Market Rules to address these CMSC payments,[10] its settlement processes do not prevent or recover these payments. The Panel encourages the IESO to implement the necessary changes to prevent or recover these unwarranted payments.

[9] For more information see the Panel's *Report on an Investigation into Possible Gaming Behaviour Related to Congestion Management Settlement Credit Payments by Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc.*, available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Investigation_Report_CMSC_Abitibi_Bowater_2015.pdf

[10] See the IESO's response to the recommendation contained in the Panel's investigation report, available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/IESO_Reply_to_OEB_MSP_20150918.pdf

Chapter 2: Market Outcomes

This chapter reports on outcomes in the IESO-administered markets for the period between November 1, 2015 and April 30, 2016 ("Current Reporting Period"), with comparisons to the period between May 1, 2015 and October 31, 2015 ("Previous Reporting Period"), as well as other periods where relevant.

1 *Pricing*

This section summarizes pricing in the IESO-administered markets, including the Hourly Ontario Energy Price (HOEP), the effective price (including the Global Adjustment (GA) and uplift charges), operating reserve (OR) prices, and Transmission Rights (TR) auction prices.

Table 2-1: Average Effective Electricity Price by Consumer Class May 2015 – October 2015 & November 2015 – April 2016 ($/MWh)

Description:

Table 2-1 summarizes the average effective electricity price[11] in dollars per megawatt hour by consumer class for the Current Reporting Period and the Previous Reporting Period. The effective electricity price is the sum of the average load-weighted HOEP, the GA, and uplift charges. Results are reported for three consumer groups: "Direct Class A consumers" (Class A consumers that are directly connected to the IESO-controlled grid); "Class B & Embedded Class A consumers" (Embedded Class A consumers being Class A consumers that are connected at the distribution level);[12] and "All Consumers", which represents what the effective electricity price would have been for all consumers but for the change in the methodology for allocating the GA that took effect in January 2011. Information pertaining to Embedded Class A consumers is aggregated with information pertaining to Class B consumers because information regarding hourly consumption by Embedded Class A consumers is not readily available. Accordingly, effective price information pertaining to Class A consumers relates only to Direct Class A consumers.

[11] This price reflects the commodity cost of electricity and does not include delivery, regulatory, and debt retirement charges.
[12] Although the Panel does not have visibility over the data, it is reasonable to assume that Embedded Class A consumers likely pay an effective electricity price similar to Direct Class A consumers. Therefore, aggregating Class B consumers and Embedded Class A consumers within a single price category likely understates the effective electricity price for Class B consumers and likely overstates the effective electricity price for Embedded Class A consumers.

Customer Class	Weighted HOEP	Average Global Adjustment	Average Uplift	Effective Price
Direct Class A - Current	10.12	48.38	1.57	60.07
Direct Class A - Previous	21.07	36.53	2.40	60.00
Class B & Embedded Class A - Current	11.15	99.47	1.63	112.25
Class B & Embedded Class A - Previous	22.76	79.53	2.48	104.77
All Consumers - Current	11.03	93.28	1.62	105.93
All Consumers - Previous	22.56	74.38	2.47	99.41

*All references to "Current" in tables and figures in this report mean the Current Reporting Period. Similarly, all references to "Previous" mean the Previous Reporting Period.

Relevance:

In Ontario, different consumer classes pay different effective electricity prices. Consumers are divided into two groups: Class A—consumers with an average peak demand above 3 MW; [13,14] and Class B—all other consumers (including, for example, all small commercial and residential consumers).[15]

Many Class B consumers—those that use less than 250,000 kWh of electricity per year are and some others—are eligible for the Regulated Price Plan ("RPP") prices set by the Ontario Energy Board ("OEB"). They pay the RPP price unless they choose to enter into a contract with an electricity retailer (in which case they pay the contract price) or they choose to opt out of the RPP. The commodity price payable by Class B consumers that are not eligible for the RPP or that opt out of the RPP depends on their meter. If they have an interval meter, they pay the HOEP. If they do not have an interval meter, they pay a weighted average HOEP based on the net system load profile in their distributor's service area. For consumers that are not on the RPP or that have signed up with a retailer the GA appears as a separate line item on their electricity bill. Since RPP prices include a forecast of the GA, the GA is not a separate item on RPP consumer bills.

[13] Effective July 1, 2015, the government of Ontario expanded the definition of Class A from consumers with a peak demand of 5 MW or greater to include a subset of consumers with a peak demand greater than 3 MW but less than or equal to 5 MW. See IESO's Industrial Conservation Initiative Backgrounder, available at: http://iesoqa-public.sharepoint.com/Documents/Expansion%20of%20the%20ICI%20Backgrounder%20-%20June%202014%20(2).pdf .
[14] As the expansion of the Class A definition occurred mid-reporting period, a weighted average of the calculation was used for the Current Reporting Period results.
[15] See Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998,* available at: http://www.ontario.ca/laws/regulation/040429.

For reference purposes, the table displays the average effective electricity price for "all consumers," which is calculated using the previous GA allocation methodology under which all consumers were allocated the GA based on their pro rata share of total consumption during the period. As of January 2011, the GA payable by Class A consumers is determined based on their peak demand factor, which is the ratio of the consumer's electricity consumption during the five peak hours[16] in a year relative to total consumption by all consumers in each of those hours. The GA continues to be charged to Class B consumers based on their total consumption during the period.[17]

In the Panel's April 2015 Monitoring Report,[18] the need to obtain generation and consumption data at an hourly level of granularity was discussed, specifically pertaining to embedded generation, behind-the-meter generation and embedded Class A consumers. While there is data on installed capacity of IESO-contracted embedded generation, the Panel noted that assessing the impacts of certain market changes is difficult, if not impossible, without generation and consumption data at the hourly level for these subsets of the Ontario electricity sector.

In a broader context, assessing the province's overall demand for electricity becomes increasingly difficult as a larger portion of that demand is no longer measured at the level of the high-voltage power system.

In particular, the Panel is interested in ascertaining the impacts of the GA allocation methodology on Class A consumption patterns for consumers that qualify for the Industrial Conservation Initiative ("ICI"). In order to more accurately calculate the effective commodity price for each consumer class in Ontario and quantify the impact of the ICI, access to hourly meter data for embedded Class A consumers and behind-the-meter generation is required. The Panel understands that the IESO is currently investigating means of collecting such information.

Commentary and Market Considerations:

[16] The five peak demand hours must occur on different days.
[17] For more information on the GA allocation methodology and its effect on each consumer class see the Panel's June 2013 Monitoring Report, pages 69-92, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf
[18] For more information on this topic see the Panel's April 2015 Monitoring Report, pages 105-109, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf

The average effective electricity price increased for both Direct Class A consumers and Class B & Embedded Class A consumers during the Current Reporting Period relative to the Previous Reporting Period. The GA was the primary driver behind increases in the effective electricity price, having increased for all consumers. The GA is primarily composed of payments to contracted and regulated generating resources that are intended to make up for shortfalls between market revenues and the contracted or regulated rates of those resources. As a consequence, the HOEP and the GA often exhibit an inverse relationship. This explains in part why the HOEP during the Current Reporting Period is less than half of what it was during the Previous Reporting Period.[19]

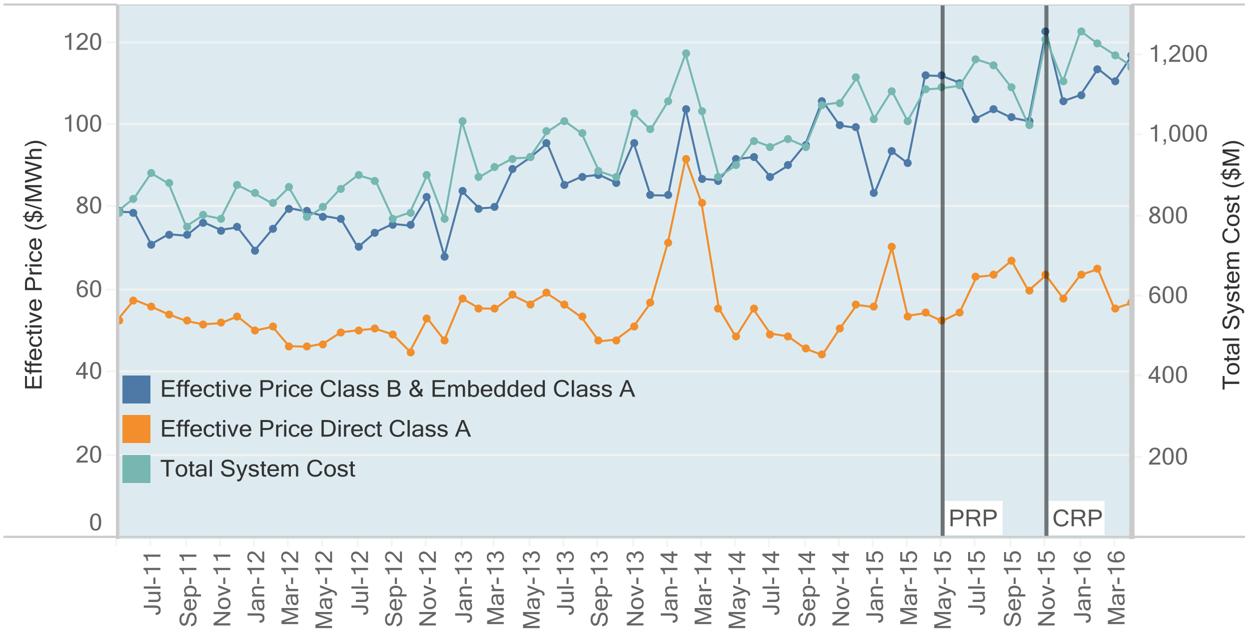
Direct Class A consumers saw the average GA increase by about $12/MWh while Class B & Embedded Class A consumers experienced an average GA increase of about $20/MWh. The average effective electricity price for both consumer classes was about $6/MWh greater in the Current Reporting Period than in the Previous Reporting Period.

Figure 2-1: Monthly Average Effective Electricity Price and System Costs May 2011 – April 2016 ($/MWh & $)

Description:

Figure 2-1 plots the monthly average effective electricity price for Direct Class A and Class B & Embedded Class A consumers, as well as the monthly average system cost (System Cost), for the previous five years.

[19] The costs associated with compensating loads under the IESO's demand response programs and administering various other conservation programs (such as the saveONenergy program) are also recovered through the GA. Additional information regarding the GA is available at: http://www.ieso.ca/sector-participants/settlements/global-adjustment-components-and-costs



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure highlights the changes in the effective electricity price paid by each consumer class over the past five years, as well as the changes in System Cost.

Commentary and Market Considerations:

In the Current Reporting Period, there were both record high total System Costs (January 2016 at $1.17B) and record high average effective electricity prices (April 2016 at $116.64/MWh) for Class B & Embedded Class A consumers. Effective electricity prices for Direct Class A consumers were little changed.

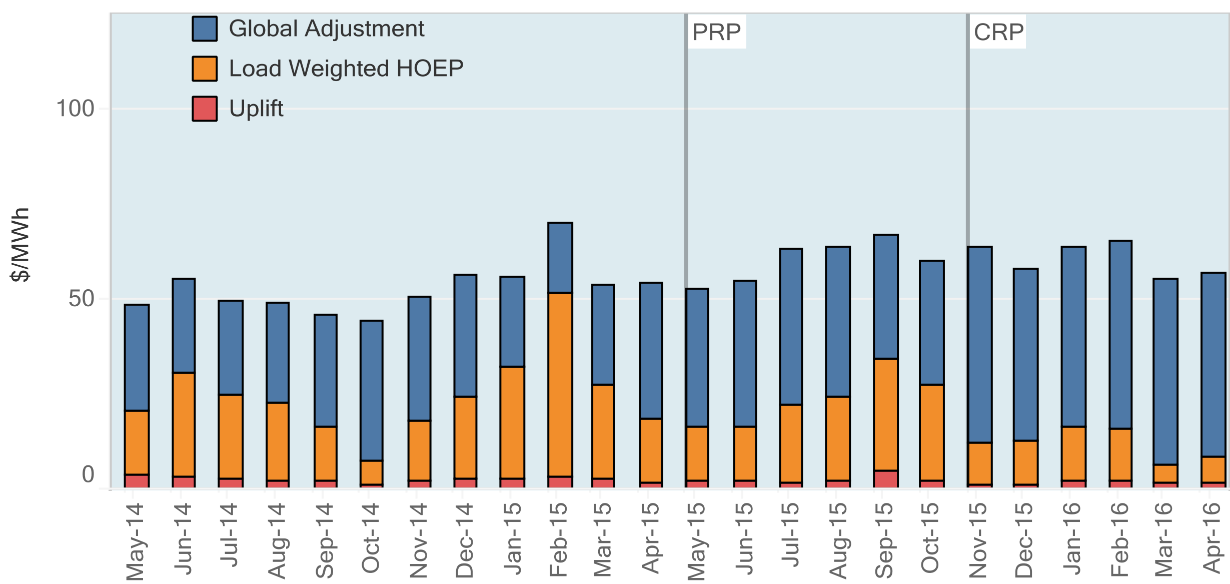
Figures 2-2A & 2-2B: Average Effective Electricity Price by Consumer Class and by Component

Description:

Figures 2-2A and 2-2B divide the monthly average effective electricity price into its three components (average HOEP, average GA, and average uplift charges) for Direct Class A consumers and Class B & Embedded Class A consumers for the previous two years.

As noted previously, the GA and the HOEP have an inverse relationship: when the HOEP decreases, the GA increases. The GA allocation methodology and the extent to which Class A consumers respond to that methodology are responsible for the significant difference in the average effective electricity price paid by each consumer group. As the GA is charged to Class A consumers based on their share of peak load during the five hours with the highest total demand in a 12-month base period,[20] Class A consumers can substantially reduce or even eliminate their GA by reducing their consumption from the IESO-controlled grid during these hours. When the average GA makes up an increasing portion of System Cost the average effective price paid by Class B consumers increases proportionately more than that paid by Class A consumers. This relationship is readily apparent in the Current Reporting Period.

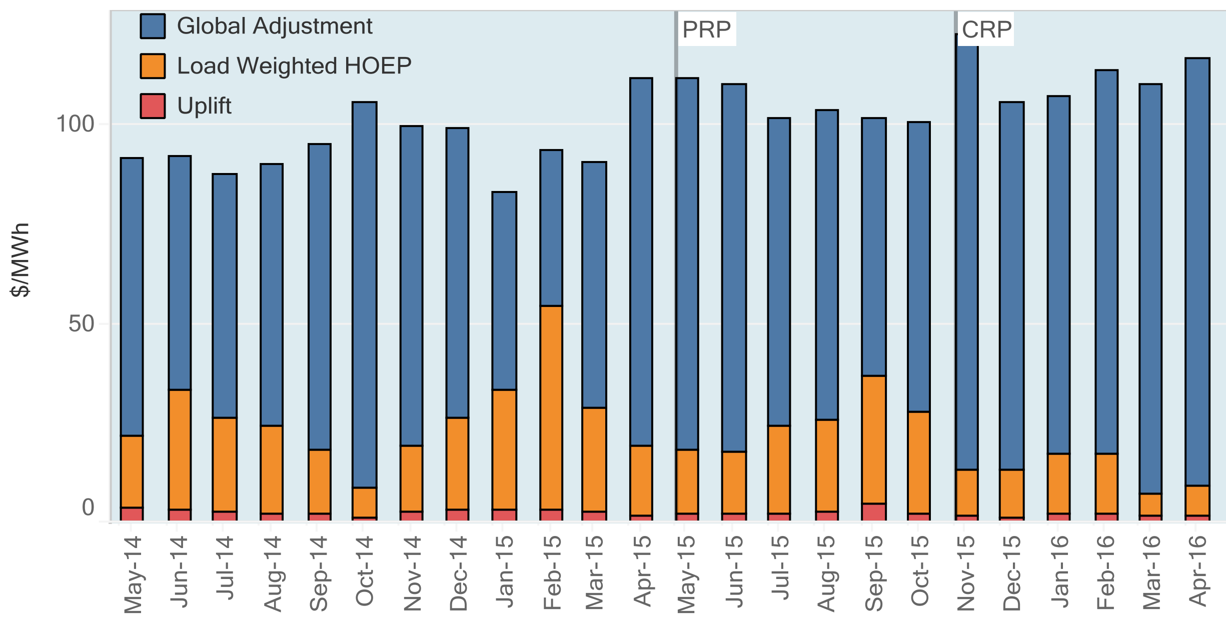
Figure 2-2a: Average Effective Electricity Price for Direct Class A Consumers by Component May 2014 – April 2016 ($/MWh)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

[20] Each base period runs from May 1 in one year to April 30 in the following year. The GA allocation for the Current Reporting Period is based on the base period from May 2015 to April 2016.

Figure 2-2b: Average Effective Electricity Price for Class B & Embedded Class A Consumers by Component May 2014 – April 2016 ($/MWh)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

These two figures illustrate how changes in the individual components of the effective electricity price affect the average effective electricity price paid by each consumer group.

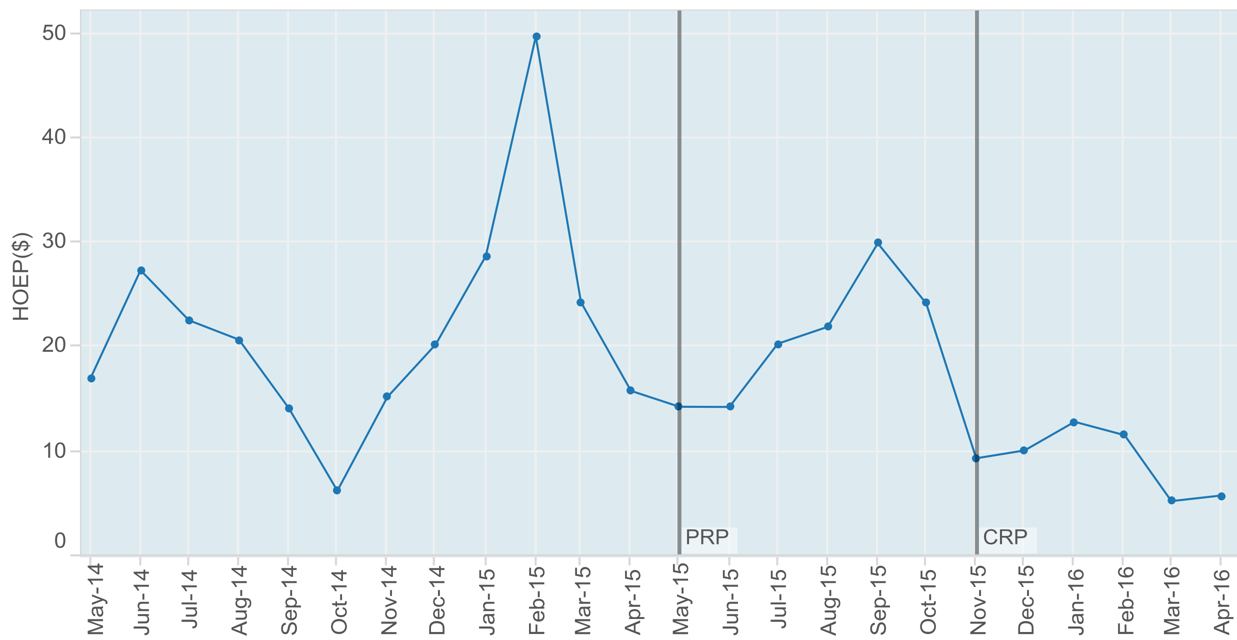
Commentary and Market Considerations:

The average effective electricity price for Class B & Embedded Class A consumers was significantly higher than that of Direct Class A consumers, as the former pay more GA compared to the latter. The GA also contributed to a record high share of the effective price in the Current Reporting Period.

Figure 2-3: Monthly (Simple) Average Hourly Ontario Energy Price (HOEP) May 2014 – April 2016 ($/MWh)

Description:

Figure 2-3 displays the simple monthly average HOEP for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The HOEP is the market price for a given hour and is one component of the effective electricity price paid by consumers. The HOEP is the simple average of the twelve Market Clearing Prices ("MCP") within the hour and that are set every five minutes. The HOEP is paid directly by consumers who participate in the wholesale electricity market, and indirectly by consumers who pay the OEB's RPP.

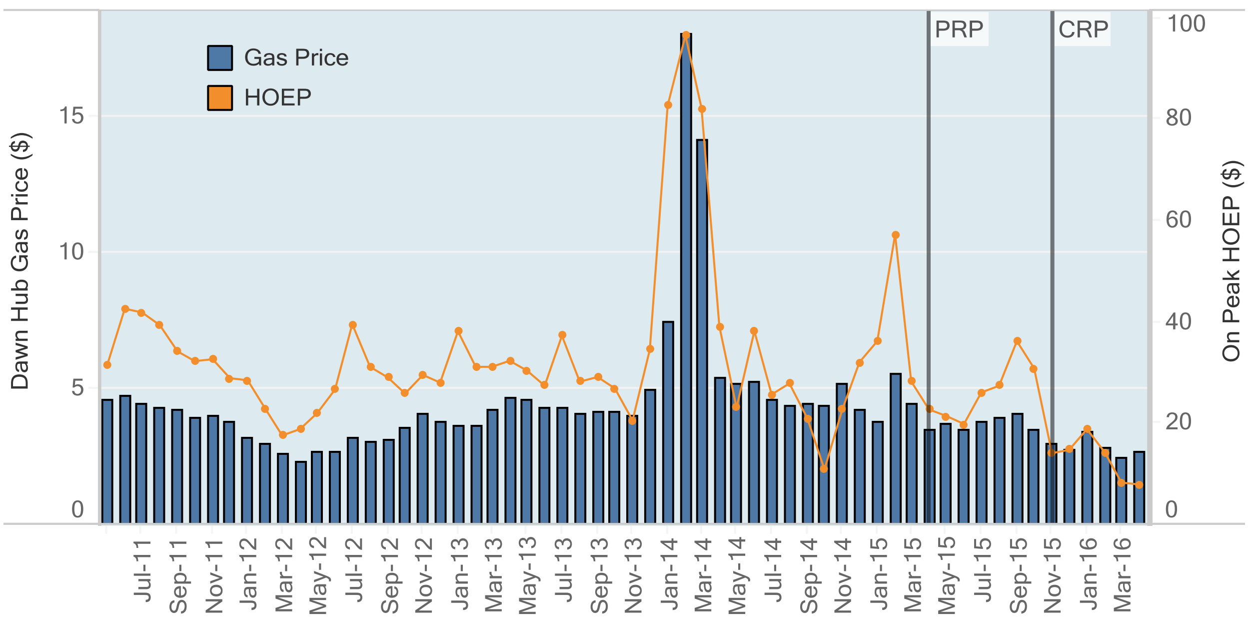
Commentary and Market Considerations:

The average HOEP of $9.09/MWh during the Current Reporting Period was significantly lower than that of both the Previous Reporting Period and the Winter 2015 Period: this is attributed to low demand and abundant supply, as nuclear units out of service in September 2015 and October 2015 were back online by the start of the Current Reporting Period and additional low marginal cost wind and solar capacity came online. The relatively low HOEP also reflects relatively low demand, owing to milder temperatures. Low demand also contributed to the Market Clearing Price ("MCP") often being set by resources offering at low prices such as wind, nuclear, and hydroelectric generation.

Figure 2-4: Natural Gas Price and On-peak Hourly Ontario Energy Price
June 2011 – April 2016
($/MWh & $/MMBtu)

Description:

Figure 2-4 plots the monthly average Dawn Hub day-ahead natural gas price and the average monthly HOEP during on-peak hours, for the previous five years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The Dawn Hub is the most active natural gas trading hub in Ontario and has the largest gas storage facility in the province. Gas-fired facilities can typically purchase gas day-ahead in order to ensure sufficient time to arrange for transportation; for that reason, the Dawn Hub day-ahead gas price is a relevant measure of the cost of natural gas in Ontario. Natural gas prices are compared to the HOEP during on-peak hours, as gas-fired facilities frequently set the price during these hours.

Commentary and Market Considerations:

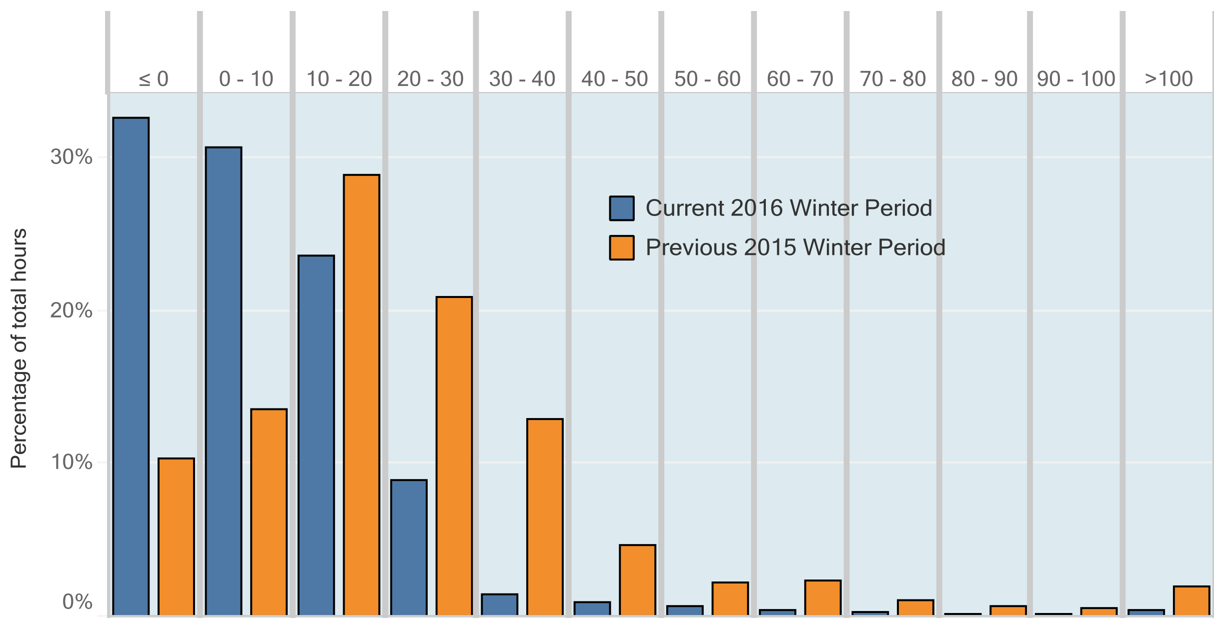
Dawn Hub gas prices have been declining since the Winter 2014 period: the Current Reporting Period had an average day-ahead gas price of $2.84/MMBtu, which was lower than that of the Previous Reporting Period at $3.72/MMBtu.

Daily changes in natural gas prices historically have been more strongly correlated with movements in the on-peak HOEP, with a correlation coefficient of 0.7069 for daily average prices from May 2011 to October 2015. The two prices have been weakly correlated in the Current Reporting Period, with a correlation coefficient of 0.3726. A contributing factor to the weak correlation is the lack of volatility in the daily average Dawn Hub gas price relative to the average on-peak HOEP.

Figure 2-5: Frequency Distribution of Hourly Ontario Energy Price
November 2014 – April 2015 & November 2015 – April 2016
(% of hours, $/MWh)

Description:

Figure 2-5 compares the frequency distribution of the HOEP as a percentage of total hours for the Current 2016 Winter Period (the same as the Current Reporting Period) and the Previous 2015 Winter Period (the same period from the previous year). The HOEP is grouped in $10/MWh increments; for example, the fourth price interval from the left counts all HOEPs greater than $20/MWh and less than or equal to $30/MWh. The negative-price hours are grouped together with all $0/MWh values in the category of HOEP less than or equal to $0/MWh.



Relevance:

The frequency distribution of the HOEP illustrates the proportion of hours that the HOEP falls into a given price range, providing information on the frequency of extremely high or low prices.

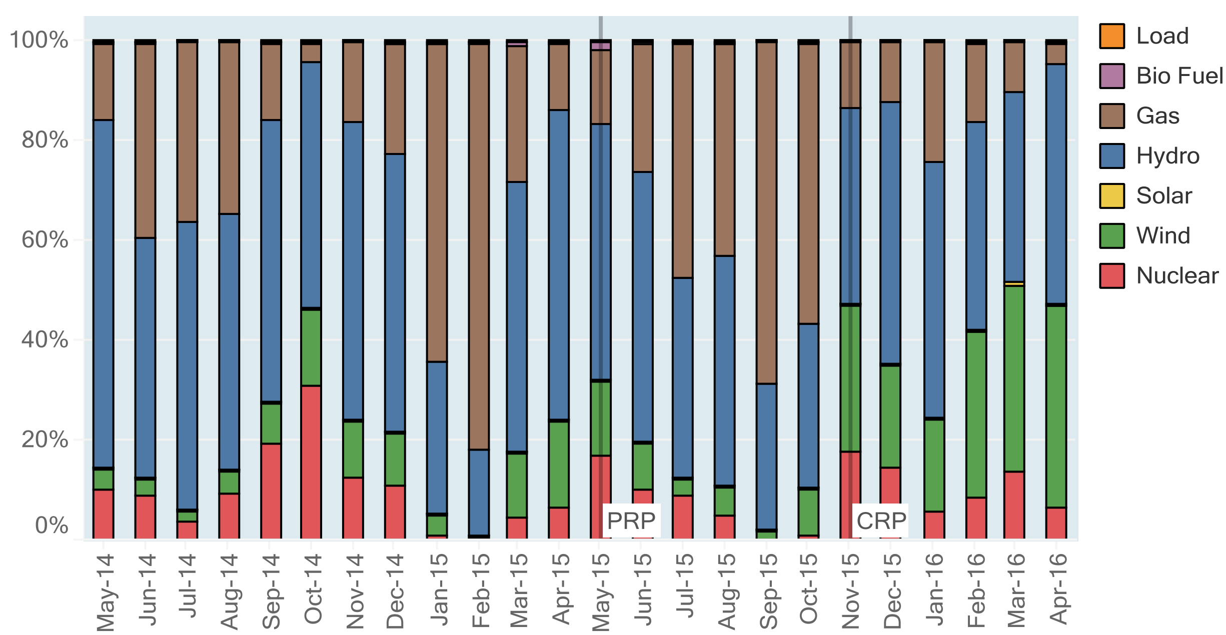
Commentary and Market Considerations:

The frequency distribution of prices illustrates a large increase in the amount of non-positive price hours (zero and negative) compared to the Winter 2015 Period. The HOEP was non-positive in 33% of hours in the Current Reporting Period. This is likely a result of the relatively low demand observed during the period, precipitated by mild weather conditions. The addition of approximately 400 MW of renewable energy capacity (which frequently offers at negative prices) was also a factor in causing lower prices. Chapter 2 examines the increase in non-positive price hours in greater detail.

Figure 2-6: Share of Resource Type setting Real-Time Market Clearing Price May 2014 – April 2016 (% of intervals)

Description:

Figure 2-6 presents the monthly share of intervals in which each resource type set the real-time MCP, for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The relative frequency of each resource type setting the real-time MCP is useful in understanding trends in the real-time MCP.

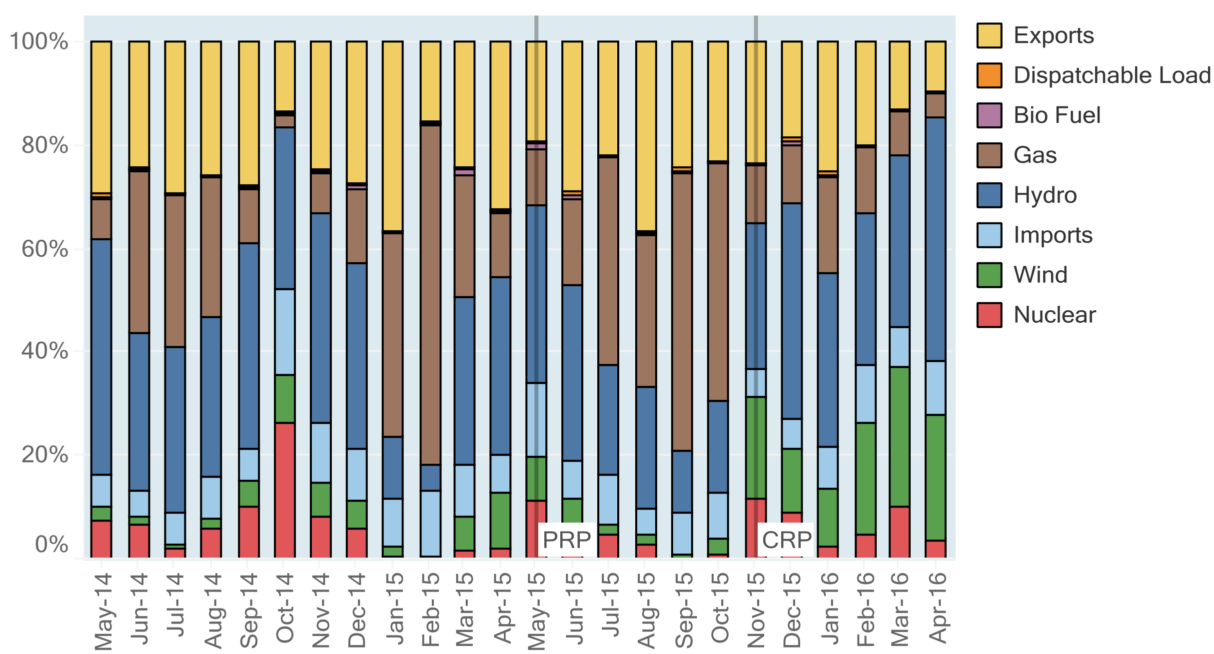
Commentary and Market Considerations:

Wind set the MCP in 30% of all intervals in the Current Reporting Period, which is more frequent than ever before. As installed wind capacity continues to increase in Ontario, the Panel expects wind to continue to set the MCP with increasing frequency, especially during periods of low demand. There has also been a significant reduction in the share of gas generators setting the market clearing price compared to the Previous Reporting Period (from 42.7% to 13.5% of all intervals) as well as compared to the Winter 2015 Period (from 37% to 13.5% of all intervals), because of mild temperatures and higher available capacity from nuclear generation.

Figure 2-7: Share of Resource Type setting the One-Hour Ahead Pre-Dispatch Market Clearing Price
May 2014 – April 2016
(% of hours)

Description:

Figure 2-7 presents the monthly share of hours in which each resource type set the one-hour ahead pre-dispatch (PD-1) MCP, for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

When compared with Figure 2-6 (resources setting the real-time MCP), the relative frequency of each resource type setting the PD-1 MCP provides insight into how the marginal resource mix changes from pre-dispatch to real-time. Of particular importance is the frequency with which imports and exports set the PD-1 MCP, as these transactions are unable to set the real-time MCP.[21] When the price is set by an import or export in pre-dispatch, a divergence between the pre-dispatch and the real-time MCP is more likely to occur.

Commentary and Market Considerations:

Similar to the Commentary for Figure 2-6, two notable observations relate to changes in the share of hours in which wind and gas-fired generators set the PD-1 price. The share of wind setting the PD-1 MCP increased from 3.6% in the Previous Reporting Period to 19.3% in the Current Reporting Period. The share of gas decreased from 33.0% in the Previous Reporting Period and from 27.0% in the 2015 Winter Period to 11.4% in the Current Reporting Period.

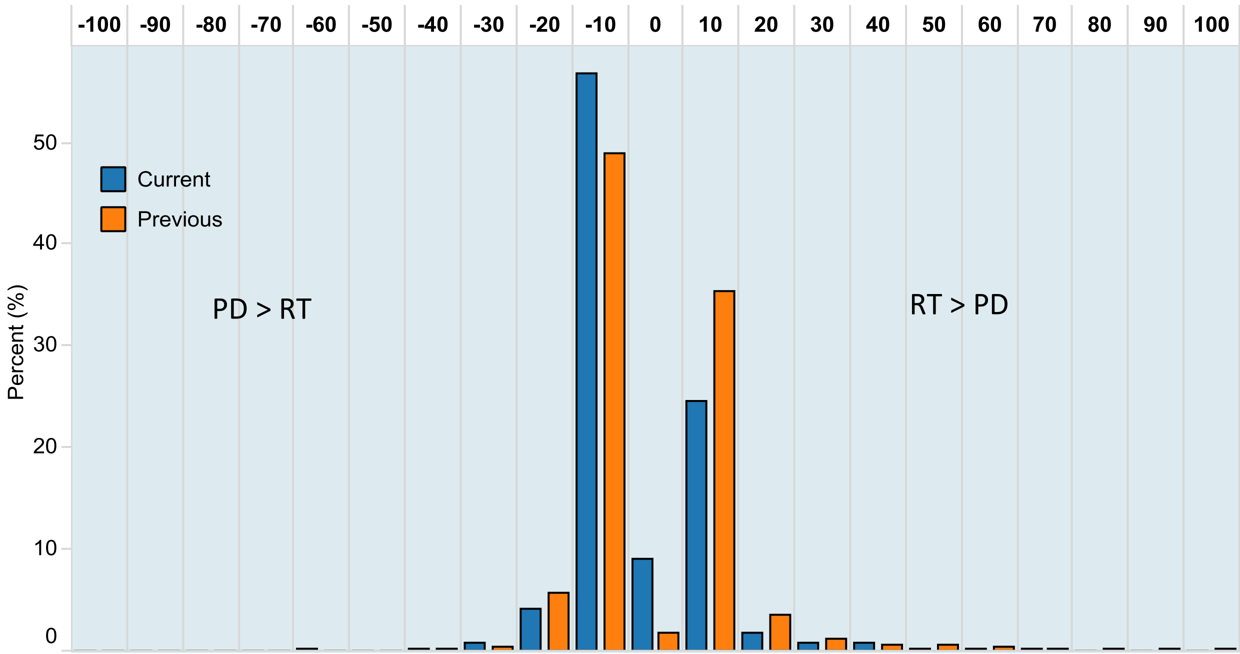
Figure 2-8: Difference between the Hourly Ontario Energy Price and the One-Hour Ahead Pre-Dispatch Price May 2015 – October 2015 & November 2015 – April 2016 (% of hours)

Description:

Figure 2-8 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Current and Previous Reporting Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-1 MCP and the HOEP. The number of instances where the absolute difference between the PD-1 MCP and the HOEP exceeded $100/MWh is negligible and so is not included in Figure 2-8, and the same is true of Figure 2-9 in relation to the absolute difference between the three-hour ahead MCP and the HOEP.

[21] Due to scheduling protocols, imports and exports are scheduled hour-ahead. Therefore, in real-time imports and exports are fixed for any given hour and their prices are adjusted in real-time to -$2,000 and $2,000/MWh, respectively. This means that they are scheduled to flow for the entire hour regardless of the price, though their schedule may change within an hour to maintain reliability. As a result, they are treated like non-dispatchable resources in real-time.

Positive differences on the horizontal axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.



Relevance:

The PD-1 MCP determines the schedules for import and export transactions for real-time delivery. While intertie transactions are scheduled on the basis of the PD-1 MCP, they are settled on the basis of the HOEP. To the degree that supply and demand conditions change from PD-1 to real-time, imports or exports may be over- or under-scheduled relative to the HOEP. For instance, an exporter that is willing to pay the PD-1 MCP may not want to pay the HOEP if it is higher (due to, for example, a generator outage that occurs between PD-1 and real-time). In such a case, if the exporter was to pay the HOEP they could lose money on the transaction. Conversely, if prices fall, the exporter could see a higher profit but the volume of exports could be sub-optimal.

Commentary and Market Considerations:

Consistent with the Previous Reporting Period, the pre-dispatch sequence over-estimated the HOEP by less than $10/MWh in more than half of all the hours. Almost 10% of the hours had no change in price between the pre-dispatch and real-time frames. The average absolute difference is $5.22/MWh in the Current Reporting Period. As this was $1.36/MWh less than that of the

Previous Reporting Period, this means PD-1 prices in the Current Reporting Period were a more accurate predictor of real-time prices.

Table 2-2: Factors Contributing to Differences between One-Hour Ahead Pre-Dispatch Prices and Real-Time Prices May 2015 – October 2015 & November 2015 – April 2016 (MWh & % of Ontario demand)

Description:

Real-time prices diverge from PD-1 prices as a result of changing conditions from pre-dispatch to real-time. The Panel has identified the following as the six main factors that contribute to the difference between the PD-1 MCP and the HOEP:

Supply

- Self-scheduling and intermittent generation forecast deviation (other than wind);
- Wind generation forecast deviation;
- Generator outages; and
- Import failures/curtailments.

Demand

- Pre-dispatch to real-time demand forecast deviation; and
- Export failures/ curtailments.

Metrics for all but one of these factors are presented in Table 2-2 as the average absolute difference between PD-1 and real-time. The effect of generator outages is not shown in this table as they tend to be infrequent, although short-notice outages can have significant price effects.

Factor	Current		Previous		Winter 2015	
	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)
Ontario Average Demand	15,435		15,205		16,461	
Pre-dispatch to Real-time Demand Forecast Deviation	219	1.42	211	1.39	213	1.29
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	65	0.42	81	0.53	55	0.33
Wind Deviation	114	0.74	112	0.74	126	0.77
Net Export Failures/Curtailments	90	0.59	82	0.54	76	0.61

Relevance:

Identifying the factors that lead to deviations between the PD-1 MCP and the HOEP provides insight into the root causes of price risks that participants, particularly importers and exporters, face as they enter offers and bids into the market.

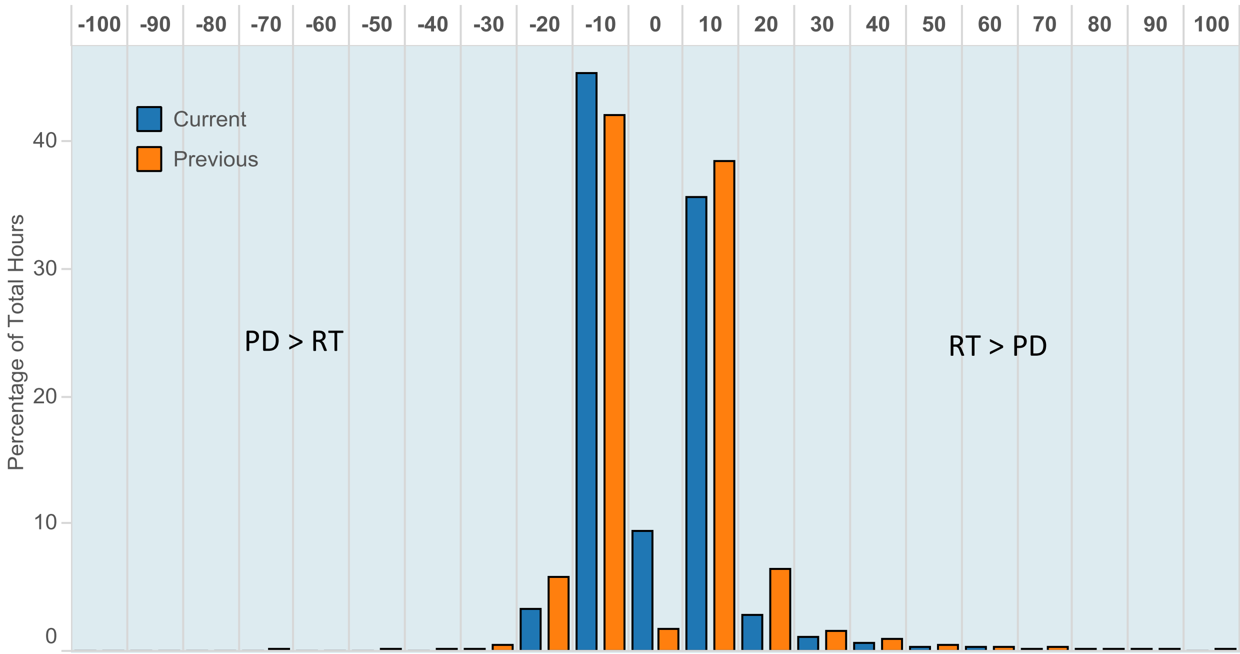
Commentary & Market Considerations:

Demand forecast deviation continues to be the largest source of price deviation, while wind forecast deviation remains the second largest factor. Compared to the Previous Reporting Period, the demand forecast deviation and wind forecast deviation remained largely unchanged.

Figure 2-9: Difference between the Hourly Ontario Energy Price and the Three-Hour Ahead Pre-Dispatch Price
May 2015 – October 2015 & November 2015 – April 2016
(% of hours)

Description:

Figure 2-9 presents the frequency distribution of differences between the HOEP and the three-hour ahead pre-dispatch (PD-3) MCP for the Current and Previous Reporting Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and the HOEP. Positive differences on the horizontal axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.



Relevance:

The PD-3 MCP is the last price signal seen by the market prior to the closing of the offer and bid window, after which offers and bids may only be changed with the approval of the IESO. Differences between the HOEP and the PD-3 MCP indicate changes in the supply and demand conditions from PD-3 to real-time. The resultant changes in price are informative for non–quick start facilities and energy limited resources,[22] both of which rely on pre-dispatch prices to make operational decisions. Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

Commentary and Market Considerations:

The frequency distribution of differences is similar between the PD-3 MCP and the PD-1 MCP. Compared to the Previous Reporting Period, PD-3 prices were better predictors of real-time prices, with smaller average and absolute average differences along with their associated standard deviations. In addition, 90% of hours observed an absolute difference smaller than

[22] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions such that they cannot operate at capacity for the entire day; instead, they must optimize their production across the highest-priced hours. For example, some hydroelectric facilities regularly experience fuel restrictions due to limited water availability.

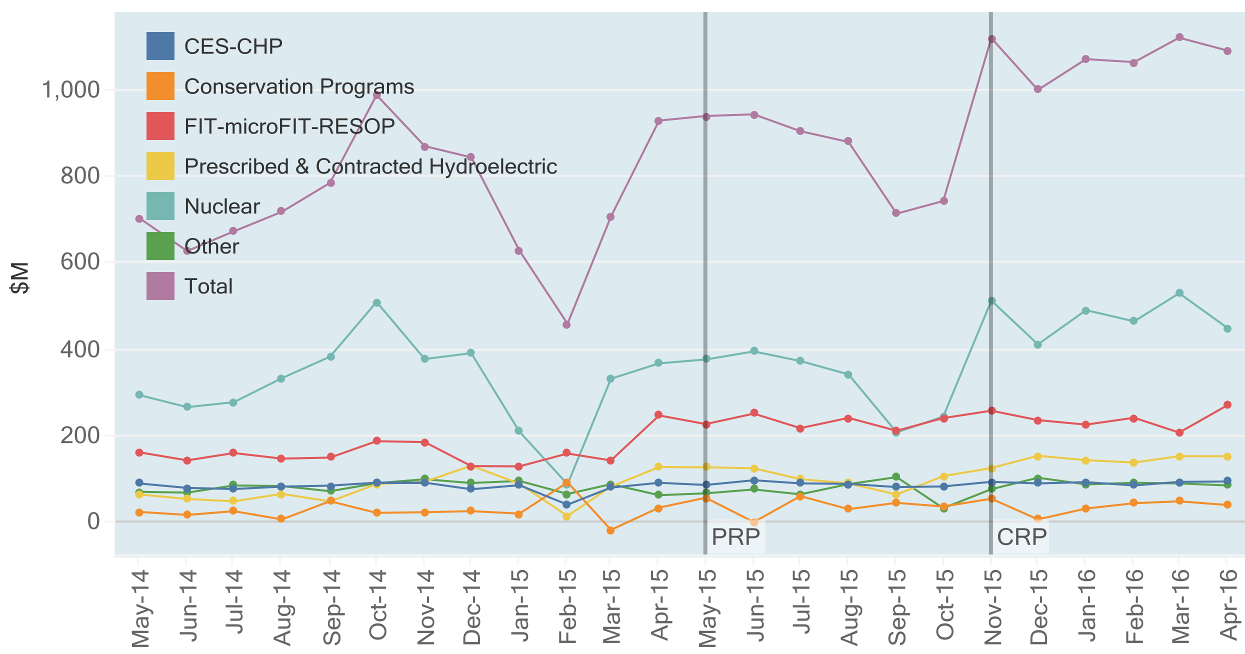
$10/MWh in the Current Reporting Period, compared to approximately 82% in the Previous Reporting Period.

Figure 2-10: Monthly Global Adjustment by Components
May 2014 – April 2016
($)

Description:

Figure 2-10 plots the revenue recovered through the GA each month, by component, for the previous two years. For this purpose, the total GA is divided into the six following components:

- Payments to nuclear facilities (Bruce Nuclear Generating Station and Ontario Power Generation's (OPG's) nuclear assets);
- Payments to holders of Clean Energy Supply and Combined Heat and Power contracts;
- Payments to prescribed or contracted hydroelectric generation;
- Payments to holders of contracts for renewable power (Feed-in Tariff ("FIT"), microFIT and the Renewable Energy Standard Offer Program);
- Payments related to the IESO's conservation programs; and
- Payments to others (including the IESO's demand response programs, non-utility generators, and OPG's Lennox Generating Station).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Showing the GA by component identifies the extent to which each component contributes to the total GA. The high GA totals for a particular component may be the result of increases in contracted rates, increased production, increased capacity, or decreases in the HOEP.

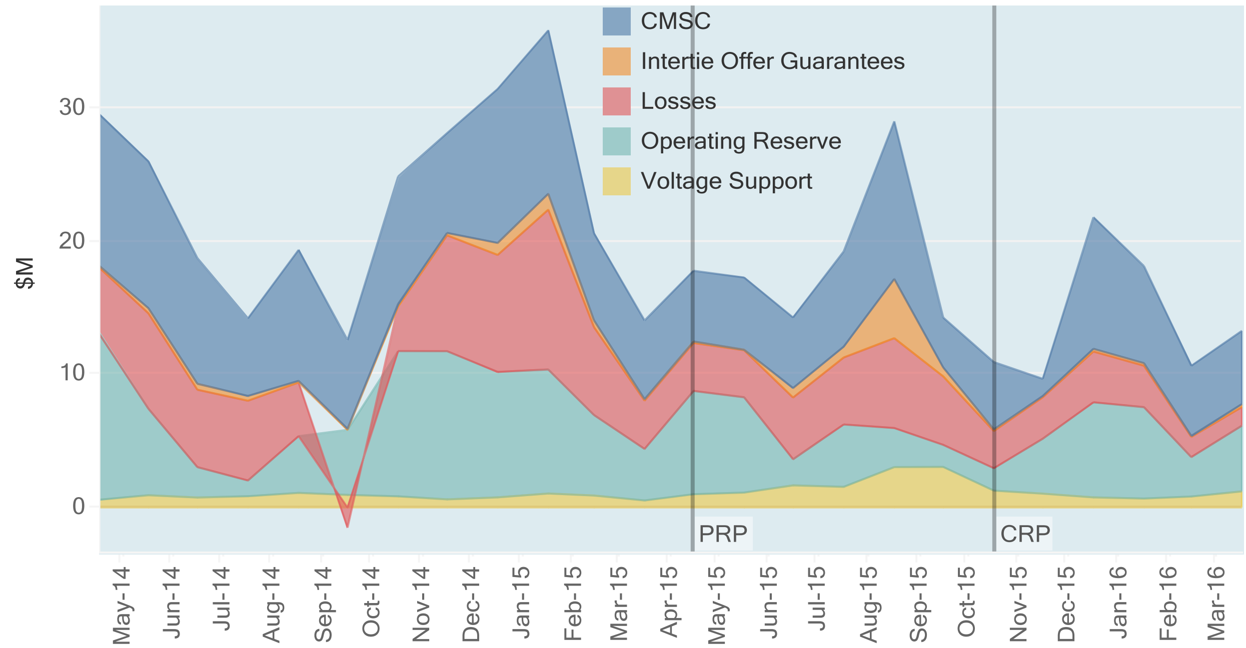
Commentary and Market Considerations:

The overall GA reached a record high of about $6.5 billion in the Current Reporting Period, owing to a comparatively mild winter resulting in lower demand and relatively low HOEP. The increase in GA is also largely attributed to the differential in nuclear payouts, which were much higher in the Current Reporting Period ($2.9 billion) compared to the Previous Reporting Period ($1.9 billion) because of a reduction in nuclear outages. Total FIT and microFIT GA payments also reached new highs ($1.4 billion) during the Current Reporting Period, reflecting an increase of approximately another 400 MW of wind and solar capacity in conjunction with the lower average HOEP.

Figure 2-11: Total Hourly Uplift Charge
By Component and Month
May 2014 – April 2016
($)

Description:

Figure 2-11 presents the total hourly uplift charges (Hourly Uplift) by component and month, for the previous two years. Hourly Uplift components include Congestion Management Settlement Credit (CMSC) payments, day-ahead and real-time Intertie Offer Guarantee (IOG) payments, Operating Reserve (OR) payments, voltage support payments, and losses.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Hourly Uplift is a component of the effective electricity price in Ontario. It is charged to wholesale consumers (including distributors) based on their share of total hourly demand in order to recover the costs associated with various market programs and design features.

Commentary and Market Considerations:

The Current Reporting Period had a lower peak hourly uplift than the Previous Reporting Period or the Winter 2015 Period, with negligible intertie offer guarantee payments. CMSC and OR were the largest sources of uplift. The relatively high OR payouts from January to February 2016 are largely attributed to increases in OR prices resulting from scarcity conditions, the mechanics of which were described by the Panel in its November 2016 Monitoring Report[23] and are mentioned in the commentary for Figure 2-13 below.

[23] Refer to MSP 27, Chapter 2.

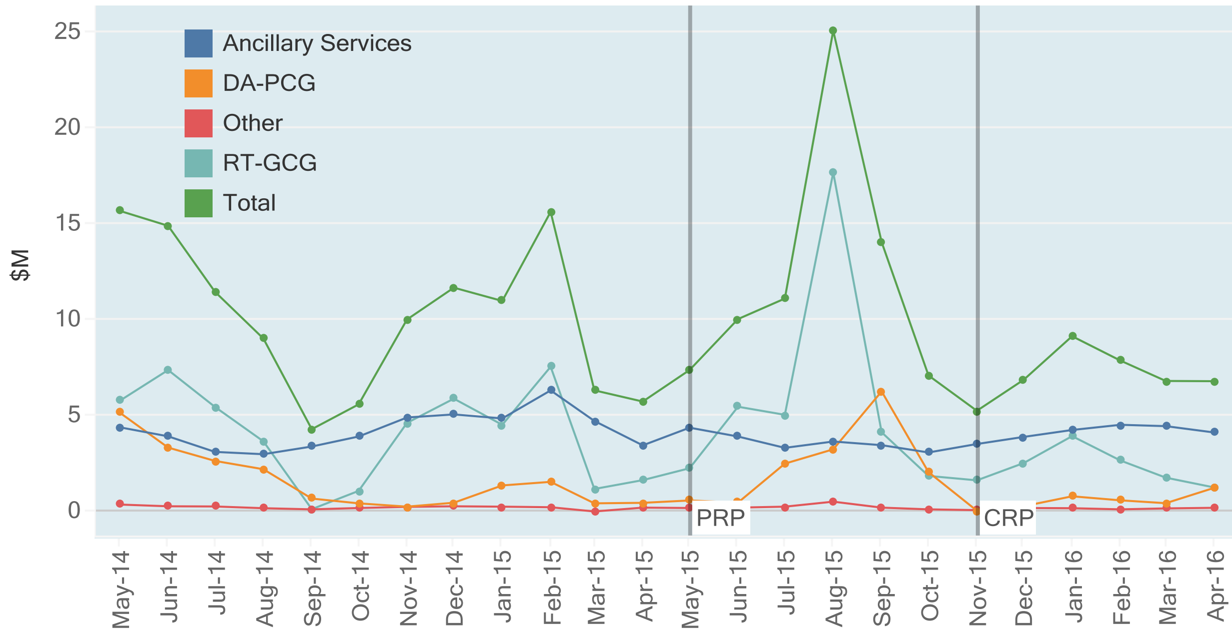
Figure 2-12: Total Monthly Uplift Charge
by Component and Month
May 2014 – April 2016
($)[24]

Description:

Figure 2-12 plots the total monthly uplift charges (Monthly Uplift) by component and month, for the previous two years. Monthly Uplift has the following components:[25]

- Payments for ancillary services (i.e., regulation service, black start capability, monthly voltage support);
- Payments for demand response capacity obligations under the DR auction;
- Guarantee payments to generators — Day-Ahead Production Cost Guarantee (DA-PCG) payments made under the IESO's Day-Ahead Commitment Program and Real-Time Generation Cost Guarantee (RT-GCG) payments made under the IESO's RT-GCG program; and
- Other, which includes charges and rebates such as compensation for administrative pricing, the local market power rebate, among others.

[24] The Panel has amended the manner in which it classifies monthly uplift charges to more closely align reported costs with the month in which they were incurred rather than the month in which they were settled. This primarily impacts the monthly reported totals for GCG payments. For example, in Figure 1-12 below, all costs submissions to the GCG program for starts occurring between August 11 and September 9, 2015 were settled at the end of September. However, the bulk of the settlements pertain to starts that occurred in August 2015. As such, the Panel reports these costs below to have occurred in August 2015, rather than September 2015. As a result of this change, monthly totals reported in this report will not match those previously reported by the Panel.
[25] The Monthly Uplifts in this figure are all uplifts that are charged other than on an hourly basis.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Monthly Uplift is a component of the effective electricity price in Ontario. It is charged to wholesale consumers (including distributors) based on their share of total daily or monthly demand, as applicable, in order to recover the costs associated with various market programs and design features.

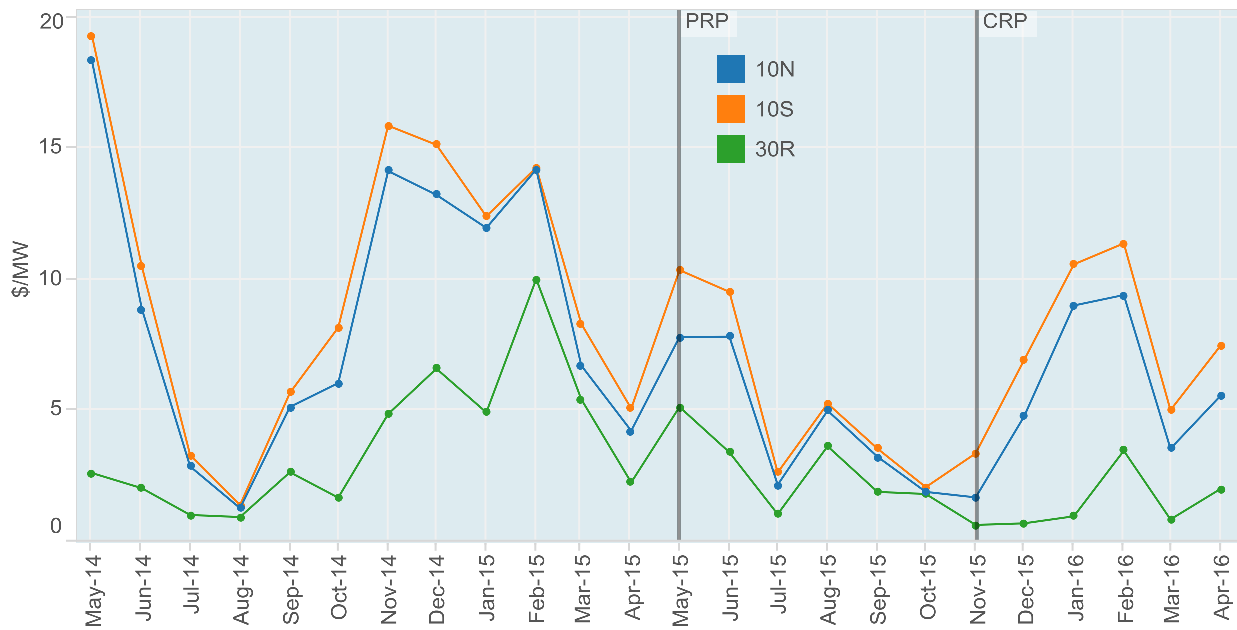
Commentary and Market Considerations:

The Current Reporting Period had relatively low monthly uplifts compared to the Previous Reporting Period. The highest monthly uplift figure during this period was $9.1 million, whereas the highest monthly uplift in the Previous Reporting Period was $25 million. The decline in Monthly Uplift over the Current Reporting Period is partially due to the decline in RT-GCG payments, from a total of $36.3 million in the Previous Reporting Period to a total of $13.7 million in the Current Reporting Period.

Figure 2-13: Average Monthly Operating Reserve Prices, by Category May 2014 – April 2016 ($/MWh)

Description:

Figure 2-13 plots the monthly average OR price for the previous two years for the three OR markets: 10-minute spinning (10S), 10-minute non-spinning (10N), and 30 minute (30R).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The three OR markets are co-optimized with the energy market, meaning that resources are scheduled to minimize the combined costs of energy and OR. As such, prices in these markets tend to be subject to similar dynamics.

Resources offer supply into the OR markets just as they offer supply into the energy market; however, OR demand is set unilaterally by the IESO's total OR requirement. The total OR requirement, as specified in the reliability standards adopted by the North American Electric Reliability Corporation and the Northeast Power Coordinating Council, is sufficient megawatts to allow the grid to recover from the single largest contingency (such as the largest generator tripping offline) within 10 minutes, plus additional OR to recover from half of the second largest contingency within 30 minutes. These requirements ensure that the IESO-controlled grid can operate reliably.

Commentary and Market Considerations:

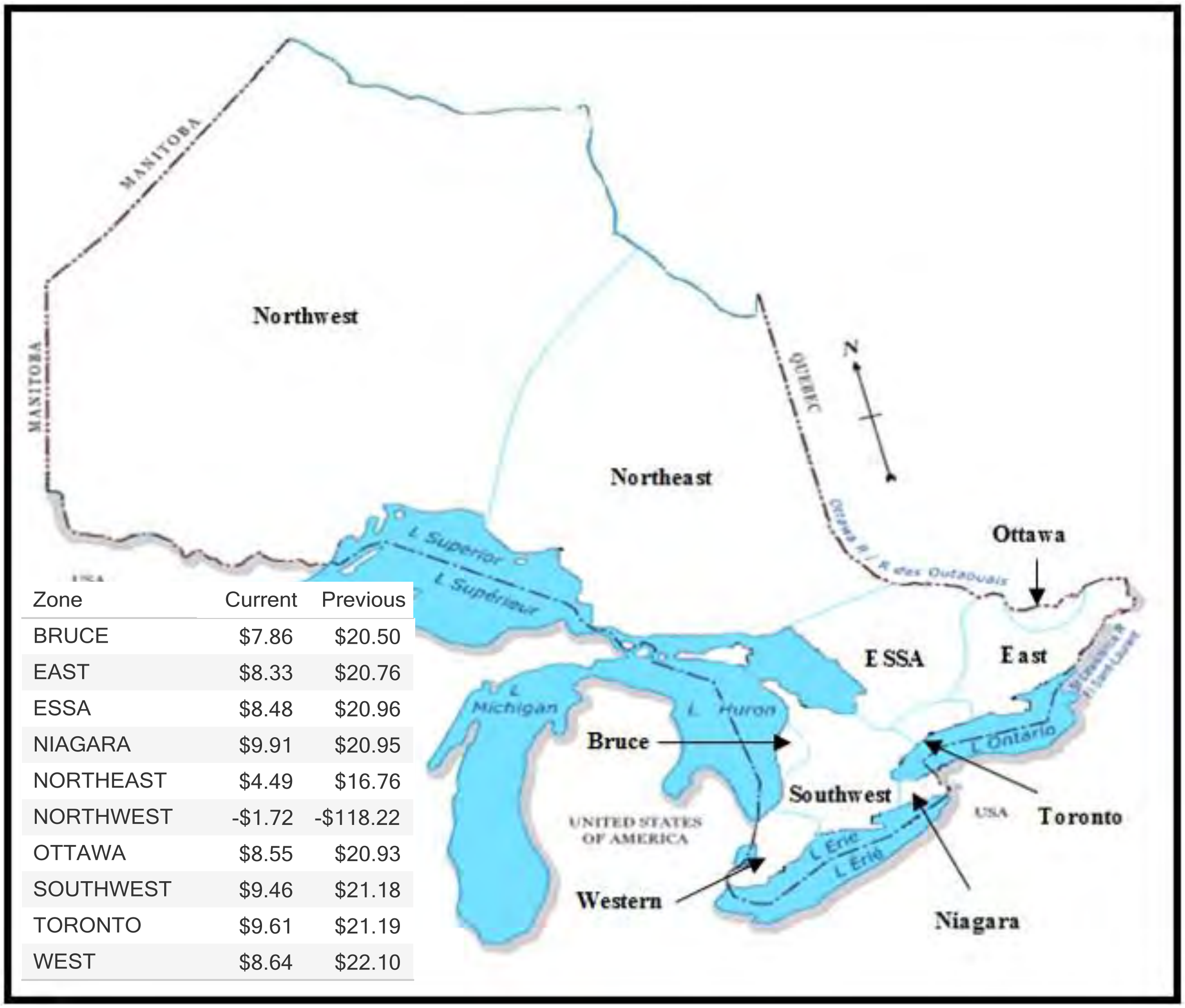
OR prices are higher relative to the Previous Reporting Period but are lower compared to the Winter 2015 period. January and February 2016 experienced relatively higher OR prices due to OR scarcity. While the majority of OR is offered by gas-fired and hydro-electric facilities, two factors have contributed to their decline. First, OR offers from hydroelectric resources have been decreasing for several years; this may be because OR revenue received by Ontario Power Generation's hydro-electric facilities is subtracted from the facilities' revenue requirement.[26] Therefore, OPG may not have a significant incentive to maximize OR revenues. The other contributor relates to Ontario's supply mix: abundant low marginal-cost supply in the form of nuclear, wind, and solar more frequently represent the marginal resource in Ontario; however, none of these resources can provide OR. When those low marginal cost resources are marginal, most non-quick start gas-fired facilities are not online, and therefore are not available to provide 10-minute operating reserve. This can result in short supply in the OR market, which generally results in higher OR prices and the increased potential of OR shortfalls. The Panel expects that higher OR prices will become more prevalent as even more renewable capacity is contracted and brought online.

Figure 2-14: Average Internal Nodal Prices by Zone
May 2015– October 2015 & November 2015 – April 2016
($/MWh)

Description:

Figure 2-14 illustrates the average nodal price of Ontario's ten internal zones for the Current and Previous Reporting Periods. In principle, nodal prices represent the cost of supplying the next megawatt of power at a given location.

[26] Refer to section 2.6 of MSP 27 Chapter 2 to examine in greater details the reasons for declining OR offers.



Zone	Current	Previous
BRUCE	$7.86	$20.50
EAST	$8.33	$20.76
ESSA	$8.48	$20.96
NIAGARA	$9.91	$20.95
NORTHEAST	$4.49	$16.76
NORTHWEST	-$1.72	-$118.22
OTTAWA	$8.55	$20.93
SOUTHWEST	$9.46	$21.18
TORONTO	$9.61	$21.19
WEST	$8.64	$22.10

Relevance:

While the HOEP is the uniform wholesale market price across Ontario, the cost of satisfying demand for electricity may differ across the province due to limits on the transmission system and the cost of generation in different regions. Nodal prices approximate the marginal value of electricity in each region and reflect Ontario's internal transmission constraints. Differences in average nodal prices identify zones that are separated by system constraints. In zones in which average nodal prices are high, the supply conditions are relatively tight; in zones in which average nodal prices are low, the supply conditions are relatively more abundant.

In general, nodal prices outside the northern parts of the province move together. Most of the time the nodal prices in the Northwest and Northeast zones are significantly lower than the nodal prices in the rest of the province due primarily to two factors: first, in these zones, there is surplus low-cost generation (in excess of local demand); and second, there is insufficient transmission to transfer this low-cost surplus power to the southern parts of the province.

Contributing to negative prices in the northern zones are hydroelectric facilities operating under must-run conditions. Must-run conditions necessitate that units generate at certain levels of output for safety, environmental, or regulatory reasons. Under such conditions, market participants offer the must-run energy at negative prices in order to ensure that the units are economically selected and scheduled.

Commentary and Market Considerations:

Nodal prices decreased among all zones, with the exception of the Northwest zone, where prices increased but were still negative. In line with changes in the HOEP attributed to milder winter conditions, relatively low demand during the Current Reporting Period resulted in lower nodal prices. In general, most zonal prices tend to move together, expect when there are outages on major transmission lines. With respect to the Northwest, however, increased net exports to Manitoba and Minnesota, as noted in Figure 2-26, were likely contributors to the price increase.

Figures 2-15 & 2-16: Congestion by Interface Group

Description:

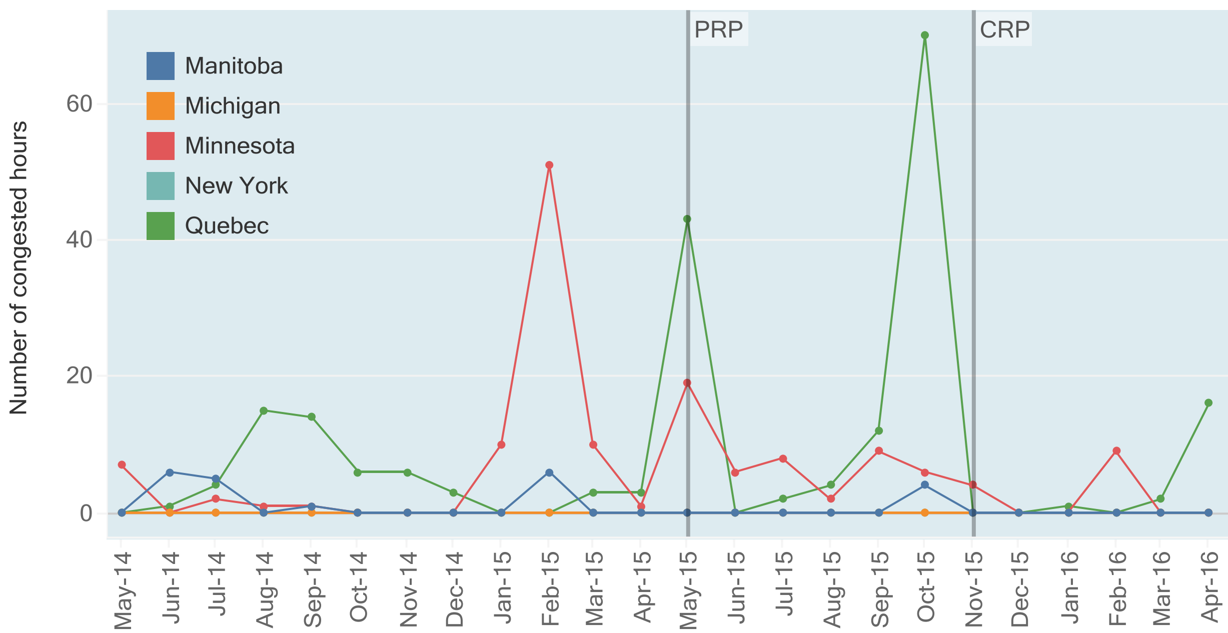
Figures 2-15 and 2-16 report the number of hours per month of import and export congestion, respectively, by interface for the previous two years.

Relevance:

The interties that connect Ontario to neighbouring jurisdictions have finite transfer capabilities. The supply of intertie transfer capability is dictated by the available capacity at each interface, and also by line outages and de-ratings. When an intertie has a greater amount of economic net import offers (or economic net export bids) than its one-hour ahead pre-dispatch transfer capability, the intertie will be import (or export) congested. Demand for intertie transfer capability is driven in part by price differences between Ontario and other jurisdictions.

The price for import and export transactions can differ from the MCP, as it is based on the intertie zonal price where the transaction is taking place. For a given intertie, importers are paid the intertie zonal price, while exporters pay the intertie zonal price. When there is import congestion, importers receive less for the energy they supply while exporters (if any) pay less for the energy they purchase—the intertie zonal price is lower than the MCP. When there is export congestion, importers (if any) receive more for the energy they supply while exporters pay more for the energy they purchase—the intertie zonal price is greater than the MCP. The difference between the intertie zonal price and the MCP is called the Intertie Congestion Price (ICP). The ICP for a given hour is calculated in PD-1 depending on whether or not the PD-1 energy schedule has more energy transactions than the intertie transmission lines can withstand. The ICP is positive when there is export congestion and negative when there is import congestion. This is discussed in more detail in the "Relevance" section associated with Figure 2-17.

Figure 2-15: Import Congestion by Interface Group
May 2014 – April 2016
(number of hours in the unconstrained schedule)

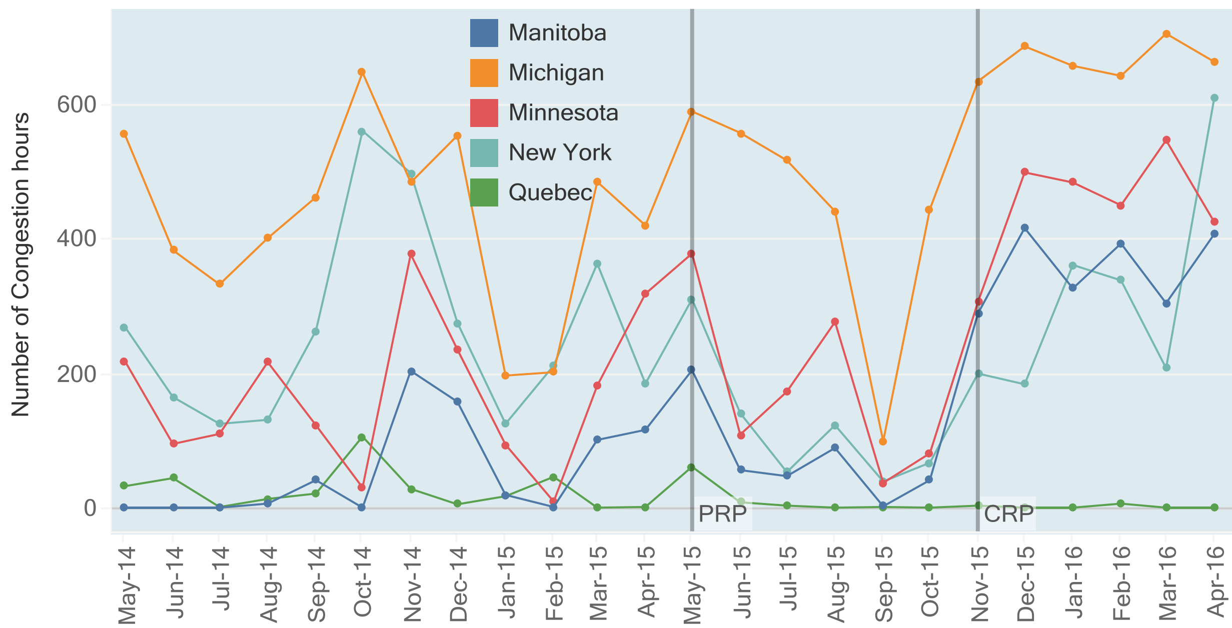


*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Commentary and Market Consideration:

Overall there were fewer import congestion hours compared to the Previous Reporting Period. Low HOEP in the Current Reporting Period resulted in relatively few imports. A depreciation of the Canadian dollar compared to the US dollar also has the effect of decreasing the profitability of importing power.

Figure 2-16: Export Congestion by Interface Group
May 2014 – April 2016
(number of hours in the unconstrained schedule)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Commentary and Market Consideration:

Export congestion increased for every intertie with the exception of Quebec. Low HOEP relative to the price in other jurisdictions had led to greater export opportunities relative to intertie capacity, leading to increased intertie congestion. Depreciation of the Canadian dollar compared to the US dollar also has the effect of increasing the profitability of exporting power.

The significant increase in export congestion hours on the New York intertie from March 2016 to April 2016 is due to transmission line limitations having restricted the New York intertie limit by at least 600 MW for approximately 66% of all hours in April.

Table 2-3: Monthly Average Hourly Wholesale Electricity Prices
in Ontario and Surrounding Jurisdictions
November 2015 – April 2016
($/MWh)

Description:

Table 2-3 lists the average hourly real-time wholesale prices for electricity, by month, in Ontario and the surrounding external jurisdictions with which electricity intertie traders operating in

Ontario commonly trade. The Ontario price reported is the HOEP. Absent congestion at an interface, importers receive, and exporters pay, the HOEP when transacting in Ontario.

The external prices reported are the real-time location-marginal prices ("LMPs") that correspond with the node on the other side of Ontario's interface with each jurisdiction. A proxy price was calculated for Manitoba as it does not operate a market. Quebéc is a frequent trading partner, but also does not operate a market. No proxy price was calculated for Quebéc. All prices are listed in Canadian dollars.

Month	Ontario (HOEP)[27]	Manitoba[28]	Michigan (MISO)[29]	Minnesota (MISO)[30]	New York (NYISO)[31]	Pennsylvania New Jersey Maryland Operator (PJM)[32]
Nov	9.29	19.26	22.72	31.27	16.91	30.50
Dec	10.04	24.15	25.65	29.90	17.90	29.67
Jan	12.78	29.22	30.55	31.56	23.69	35.90
Feb	11.5	24.41	26.43	29.46	19.19	31.79
Mar	5.19	19.24	21.99	26.65	10.45	18.06
Apr	5.73	17.98	21.00	28.18	24.77	27.71

Relevance:

One objective of energy trading is to exploit arbitrage opportunities. Intertie traders attempt to purchase (export) low-priced power from one jurisdiction and sell (import) that power to another jurisdiction at a higher price to capture the price differential.[33]

[27] All prices listed for each jurisdiction reflect the marginal price of energy. Costs associated with capacity, such as Ontario`s global adjustment or NYISO, PJM, or MISO's capacity markets, are not considered in inter-jurisdictional trade.
[28] The Panel assumed that the real-time LMPs at the 'MHEB' node published by MISO are representative of the external prices at the Manitoba interface.
[29] The Panel assumed that the real-time LMPs at the 'ONT_DECO_PSOUT' node published by MISO are representative of the external prices at the Michigan interface.
[30] The Panel assumed that the real-time LMPs at the 'ONT_W' node published by MISO are representative of the external prices at the Minnesota interface.
[31] The Panel assumed that the real-time LMPs at the 'OH' node published by NYISO are representative of the external prices at the New York interface.
[32] The Panel assumed that the real-time LMPs at the 'IMO' node published by PJM are representative of the external prices in PJM that exporters can capture by wheeling through New York or Michigan.
[33] Differences exist in terms of the specific costs that are included in the spot price of electricity between jurisdictions. For example, in Ontario, the HOEP is not reflective of a gas-fired generation unit's start-up costs, as these costs are a component of uplift, which is settled out-of-market. The specific components that comprise the spot price will vary from jurisdiction to jurisdiction, but they are still the most accurate and readily available indicators of economic decision making in real-time for intertie traders.

Price differences between jurisdictions can change from one hour to the next due to changes in any of the numerous factors which determine demand (e.g. weather) and supply (e.g. outages). Changes in the price differential will impact the direction of energy trade between those jurisdictions. Energy trade may not always flow from jurisdictions with low prices to jurisdictions with high prices; imperfect information, timing issues and rapidly changing conditions can lead to energy trade that appeared efficient ex-ante but ends up being inefficient or unprofitable ex-post. However, average prices over longer time horizons should be informative on trends in the direction of energy trade between jurisdictions. Over the course of a month if the average energy price in Ontario is lower than another jurisdiction, energy trade should flow from Ontario to that jurisdiction in that month on a net basis.

Congestion can erode or even reverse the original arbitrage opportunity between the HOEP and the external jurisdiction's price. However, the two key pieces of information in determining whether to import to or export from Ontario are the HOEP and the spot price in the external jurisdiction.

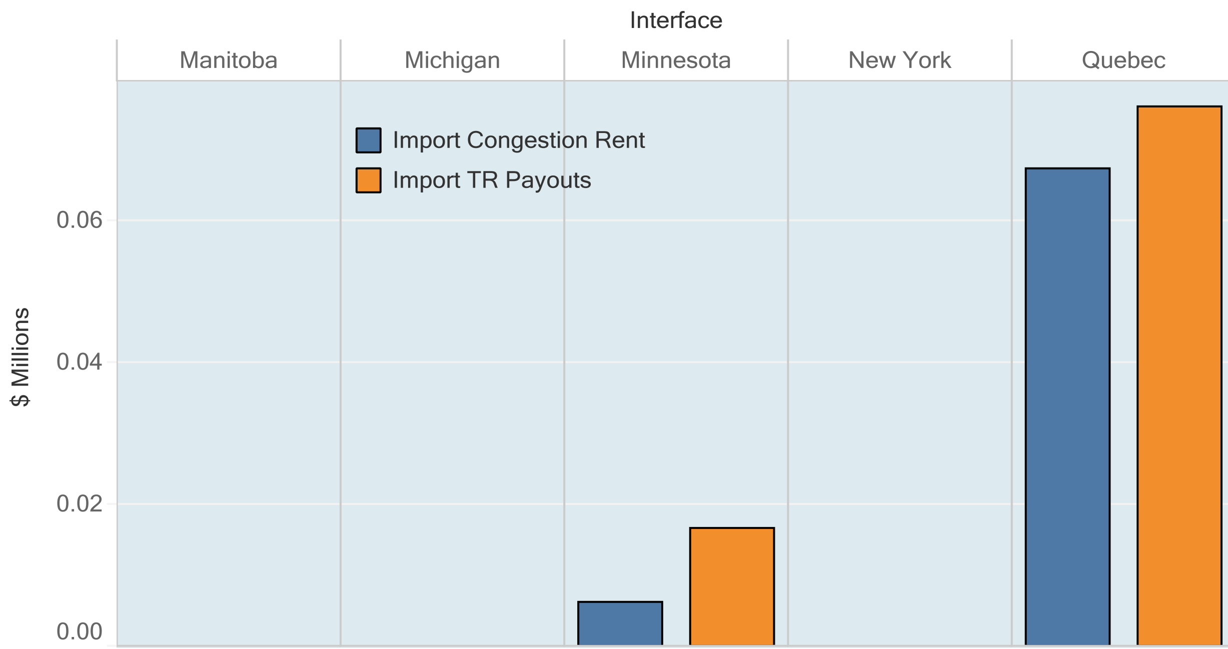
Commentary and Market Considerations:

In line with observations from Figures 2-15 and 2-16, Ontario's HOEP was significantly lower than the energy price in all of the surrounding jurisdictions; hence it was a net exporter during the Current Reporting Period.

Figure 2-17: Import Congestion Rent &
Transmission Rights Payouts by Interface Group
November 2015 – April 2016
($)

Description:

Figure 2-17 compares the total collection of import congestion rent to total TR payments by interface group for the Current Reporting Period.



Relevance:

As discussed in the relevance section associated with Figures 2-15 and 2-16, an intertie zonal price is less than the Ontario price when an intertie is import congested; the difference in prices is the ICP and is equal to the difference (if any) between the PD-1 Ontario price and the PD-1 intertie zonal price. While the importer is paid the lesser intertie zonal price, the buyer in the wholesale market still pays the HOEP. The difference between the amount collected from the purchaser and the amount paid to the importer is known as import "congestion rent". Congestion rent accrues to the IESO's TR Clearing Account. This account is discussed in greater detail in the Relevance section associated with Figure 2-19.

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold on the basis of intertie and direction (import or export) for periods of one month or one year. The owner of a TR is entitled to a payment (or "payout") equal to the ICP multiplied by the amount of TRs they hold every time congestion occurs on the intertie in the direction for which they own a TR. TRs therefore allow an intertie trader to hedge against congestion-related price fluctuations by ensuring that intertie traders are settled on the HOEP and not the intertie zonal price. An intertie trader that holds the exact same amount of import TRs as the amount of energy they are importing is perfectly hedged against congestion, as TR payouts will exactly offset price differences between the Ontario price and the price in the intertie zone. Payouts to TR holders are disbursed from the TR Clearing Account.

While TR payouts should theoretically be offset by congestion rent collected, in practice this is seldom the case. One of the main reasons for this is the difference between the number of TRs held by market participants and the number of net imports/exports flowing during hours of congestion. When TR payouts exceed congestion rent collected, the TR Clearing Account is drawn down; the opposite is true when congestion rent collected exceeds TR payouts.

In addition to congestion rent collected and TR payouts, there is a third input to the TR Clearing Account—TR auction revenues. TR auction revenues are the proceeds from selling TRs (a payment into the TR Clearing Account). Due to Ontario's two-schedule price system,[34] transaction failures and intertie de-ratings, there are congestion events in which a congestion rent shortfall arises; instead of remaining revenue neutral, these events draw down the TR Clearing Account. These shortfalls are covered primarily by TR auction revenues. The Panel has previously expressed the view that TR auction revenues should be for the benefit of consumers in the form of a reduction in transmission charges.[35] In that context, every dollar of congestion rent shortfall represents a dollar that does not accrue to the benefit of Ontario customers. The IESO has recently made changes to its TR auction process to address recurring congestion rent shortfalls, which is discussed further in the Relevance section associated with Figure 2-19.

Note that interties with a high frequency of import congestion hours (see Figure 2-15) do not necessarily correlate with high import TR payouts and import congestion rent, primarily because of the differences in intertie capacity (and thus TRs sold) at each intertie.

[34] Intertie congestion (and thus the ICP and TR payouts) is calculated based on the pre-dispatch unconstrained schedule, while congestion rent collected is based on the real-time constrained schedule. To the degree that the pre-dispatch unconstrained schedule differs from the real-time constrained schedule, TR payouts may differ from congestion rent collected. In the extreme, congestion may occur in one direction (*e.g.,* import) in the pre-dispatch unconstrained schedule, but the real-time constrained schedule has net transactions in the opposite direction (*e.g.,* export). In this case, import TR payouts are made and negative import congestion rents are "collected".

[35] If there were no TRs in Ontario, but all other aspects of the market design were retained, congestion rent would still be collected by the IESO whenever there was congestion on an intertie. Those congestion rents are the price importers and exporters are prepared to pay for scarce transmission capacity, suggesting that rents might be paid to transmission owners. But as the transmission companies are rate-regulated entities, any congestion rents paid to them would presumably be used to offset their regulated revenue requirement. Thus, their customers (Ontario consumers) would benefit from congestion rents. For more information on the TR market and the basis for disbursing funds from the TR Clearing Account to offset transmission service charges, see the Panel's January 2013 Monitoring Report, pages 146-160, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf

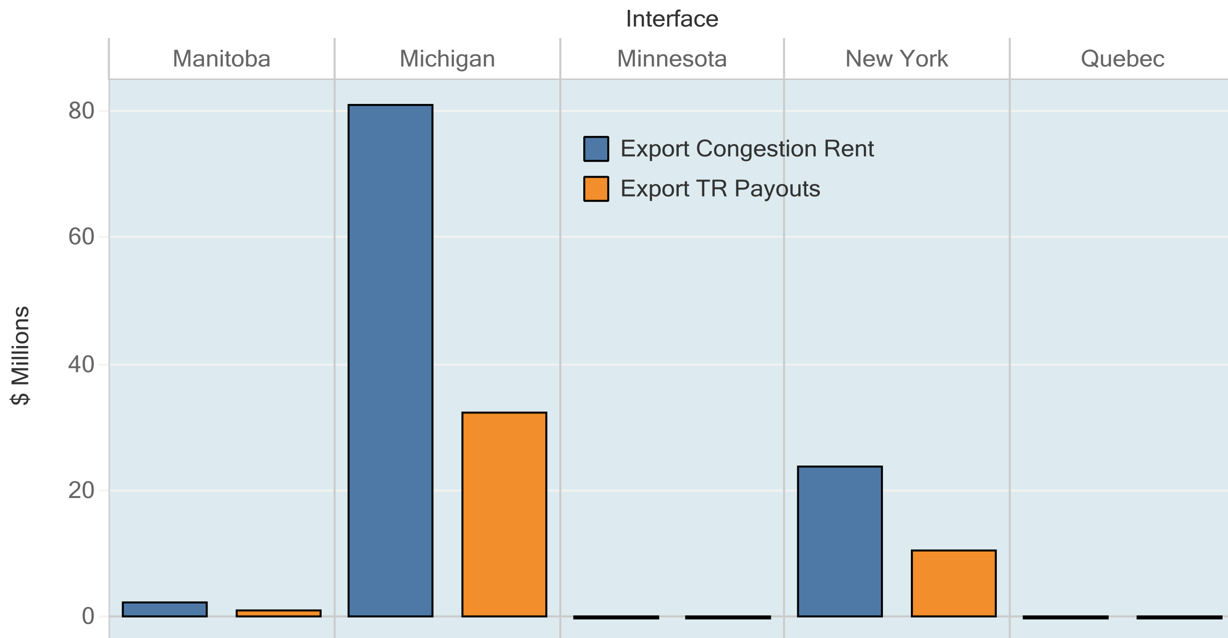
Commentary and Market Consideration:

There were very little import congestion rents paid out during the Current Reporting Period. This is because the HOEP was considerably less than the market prices in neighbouring jurisdictions, meaning there were fewer opportunities to import.

Figure 2-18: Export Congestion Rent &
TR Payouts by Interface Group
November 2015 – April 2016
($)

Description:

Figure 2-18 compares the total collection of export congestion rent to total TR payouts by interface group for the Current Reporting Period.



Relevance:

When there is export congestion, an intertie zonal price is more than the Ontario price. See the Relevance section associated with Figure 2-17 that describes the relationship between congestion rents and TR payments in regards to import congestion. The relationship between congestion rents and TR payments for export congestion is the converse of that for import congestion. In general, if there are less congestion rents collected, there is a congestion rent shortfall (and the TR Clearing Account balance decreases); if there are more congestion rents collected than TR payments, there is a congestion rent surplus (and the TR Clearing Account balance increases).

Commentary and Market Consideration:

Compared to the Previous Reporting Period, export congestion rents for the New York and Michigan interties more than doubled, while TR payouts effectively remained unchanged between the Current and Previous Reporting Periods. The New York and Michigan interfaces were the primary contributors to congestion rent, with the latter being the most heavily export congested interface in the Current Reporting Period, as seen in Figure 2-16. The average hourly export capacity of the interface exceeded average hourly export TR ownership over the Current Reporting period by 346 MW and 99 MW for Michigan and New York respectively. In general, TRs can be undersold relative to the intertie capacity owing to line and equipment outages or system security requirements that suppress the IESO's forecast of the intertie's capacity.

Table 2-4: Average Long-Term (12-month) Transmission Right Auction Prices by Interface and Direction May 2015 – February 2016 ($/MW)

Description:

Table 2-4 lists the weighted average auction prices of 1 MW of long-term (year-long) TRs sold for each interface, in either direction, since May 2015 (these TRs would have been valid during the Current Reporting Period).

Direction	Auction Date	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Quebec
Import	May-15	Jul-15 to May-16	3,294	511	5,306	456	2,454
	Aug-15	Oct-15 to Aug-16	2,844	505	4,445	404	1,106
	Nov-15	Jan-16 to Dec-16	1,735	389	3,707	224	1,850
	Feb-16	Apr-16 to Mar-17	1,796	339	3,487	208	1,118
Export	May-15	Jul-15 to May-16	15,883	62,961	26,374	42,910	6,745
	Aug-15	Oct-15 to Aug-16	12,605	72,534	21,850	51,193	9,865
	Nov-15	Jan-16 to Dec-16	8,828	61,875	19,034	29,036	4,383
	Feb-16	Apr-16 to Mar-17	19,595	78,135	25,276	34,165	2,980

Relevance:

If an auction is efficient, the price paid for one megawatt of TRs should reflect the expected payout from owning that TR for the period. This is equivalent to the expected sum of all ICPs in the direction of the TR over the period for which the TR is valid. The greater the expected frequency and/or magnitude of congestion on the intertie, the more valuable the TR. Assuming an efficient auction, auction revenues signal the market's expectation of intertie congestion conditions for the forward period.

Commentary and Market Consideration:

Given Ontario's position as a net exporter of energy, auctions prices for long-term TRs were generally higher for exports than for imports across all interties. There has been a decrease in long-term import TR prices from the Previous Reporting Period to the Current Reporting Period across all interties: this may be indicative of market participants' expectations that import congestion will not be as prominent in the upcoming winter. With the exception of the New York and Michigan interties, there were no major price fluctuations for long term TR's between the Current and Previous Reporting Periods. The relatively material decrease in long-term export TR prices at New York is predictive of fewer export congestion hours in subsequent monitoring periods. Michigan is the only intertie with long-term TR prices that have increased, albeit slightly, from the Previous to the Current Reporting Period: the high occurrence of export congestion on the Michigan intertie is expected to persist.

Table 2-5: Average Short-Term (One-month) Transmission Right Auction Prices by Interface and Direction
May 2015 – April 2016
($/MW)

Description:

Table 2-5 lists the auction prices for 1 MW of short-term (month-long) TRs sold at each interface, in either direction, during the Previous and Current Reporting Periods.

Direction	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Quebec
Import	May-15	310	55	418	90	135
	Jun-15	317	16	-	16	90
	Jul-15	387	12	-	11	81
	Aug-15	417	30	201	7	79
	Sep-15	202	12	164	7	0
	Oct-15	135	19	290	15	118
	Nov-15	165	15	122	15	5
	Dec-15	117	0	201	0	28
	Jan-16	103	0	327	1	20
	Feb-16	121	0	143	0	28
	Mar-16	98	0	126	0	40
	Apr-16	113	14	130	0	82
Export	May-15	810	4,494	1,735	2,262	179
	Jun-15	1,300	5,575	-	2,520	27
	Jul-15	751	6,897	-	2,645	82
	Aug-15	459	7,462	-	930	37
	Sep-15	580	5,947	-	1,125	6
	Oct-15	393	2,701	-	671	123
	Nov-15	310	4,009	-	2,297	72
	Dec-15	457	4,494	-	1,208	220
	Jan-16	1,001	4,621	-	1,305	826
	Feb-16	1,510	6,145	-	1,655	355
	Mar-16	2,612	7,373	-	2,875	186
	Apr-16	2,320	6,586	-	1,523	10

Relevance:

As discussed in the relevance section associated with Table 2-4, auction revenues signal market participant expectations of intertie congestion conditions for the forward period.

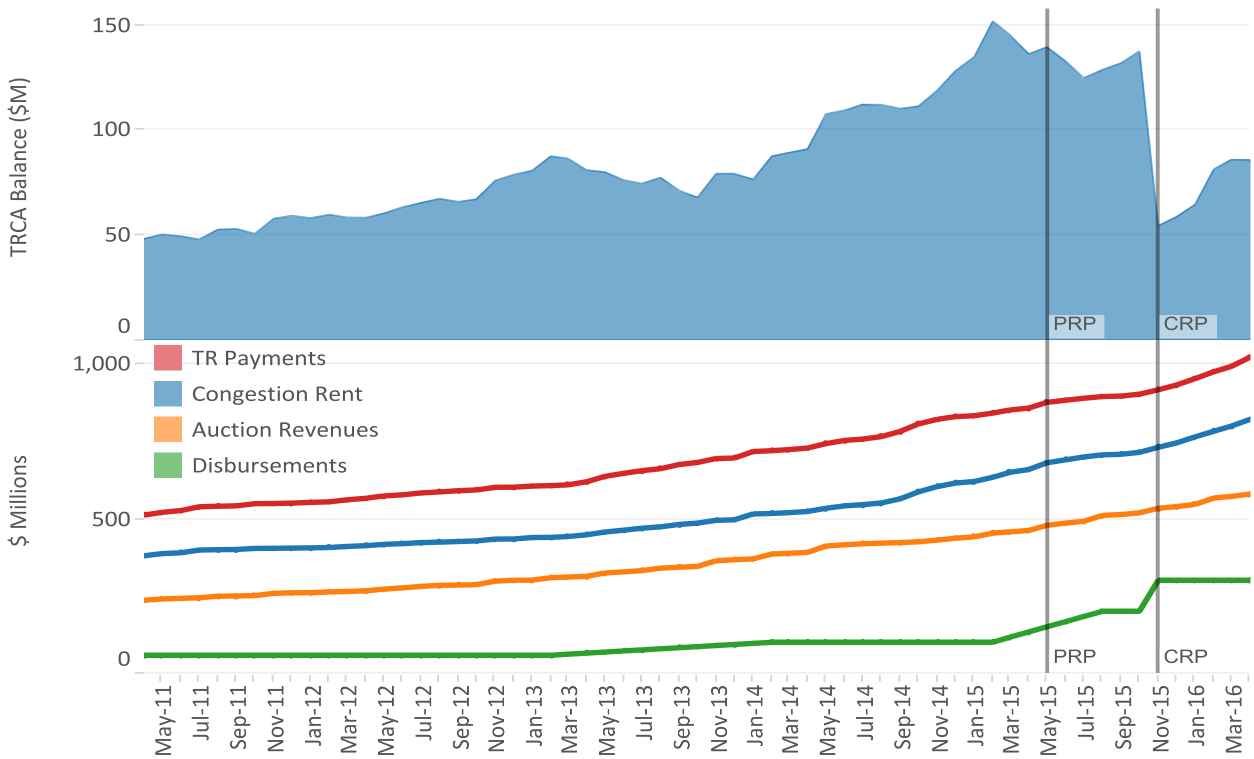
Commentary and Market Consideration:

Short-term import TR prices were consistent with the long-term TR auction. Regarding short-term export TR's, none were sold to Minnesota in this monitoring period. The short-term export TR prices at the Manitoba intertie almost tripled from the Previous to Current Reporting Period, which indicates a correct anticipation for the increased occurrence of export congestion hours at the Manitoba intertie, as illustrated in Figure 2-16. Trends in short-term export TR prices were consistent with the long-term TR auction for New York and Michigan.

Figure 2-19: Transmission Rights Clearing Account
May 2011 – April 2016
($)

Description:

The TR Clearing Account is an account administered by the IESO to record various amounts relating to TRs. Figure 2-19 shows the estimated balance in this account at the end of each month for the previous five years, as well as a breakdown by its component transactions.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The TR Clearing Account balance is affected by five types of transactions:

<u>Credits</u>

- Congestion rent received from the market
- TR auction revenues
- Interest earned on the TR Clearing Account balance

<u>Debits</u>

- TR payouts to TR holders
- Disbursements to Ontario market participants

Tracking TR Clearing Account transactions over a period of time provides an indication of the health of the TR market and the policies that govern it. The account has a reserve threshold of $20 million set by the IESO Board of Directors; funds in excess of this threshold can be disbursed to wholesale loads and exporters at the discretion of the IESO Board of Directors.

Commentary & Market Considerations:

In the Current Reporting Period, the balance in the TR Clearing Account decreased by $51.78 million; from $137.31 million at the end of the Previous Reporting Period to $85.53 million at the end of the Current Reporting Period, thus ending $65.53 million above the Reserve Threshold. This change was composed of:

- $168.26 million in revenues
    - $107 million in congestion rent collected
    - $60.96 million in auction revenues
    - $0.30 million in interest (this was negligible and was therefore removed from the figure)
- $220.5 million in disbursements
    - $120.05 million in TR payments to rights holders
    - $100 million in disbursement to Ontario consumers in November 2015
        - This particular disbursement is discussed in more detail in Chapter 3 of this report

Total auction revenues increased by $4 million from the Previous Reporting Period to the Current Reporting Period. This change is likely attributed to a net increase in export TR prices coupled with relatively immaterial fluctuations in import TR prices, as summarized in Table 2-4 and Table 2-5.

Congestions rents increased by $52 million, while TR payouts increased by $75 million from the Previous Reporting Period to the Current Reporting Period. As noted in Figure 2-16, depreciation in the Canadian dollar relative to the US dollar had the effect of increasing the profitability of exporting power. This has contributed to an increase in the number of export congestion hours in all interties from the Previous Reporting Period to the Current Reporting Period, which in turn has increased the opportunity to collect congestion rents and make TR payments.

The Panel expands on the interdependencies between each component of the TR Clearing Account from section 3.1.1 to section 3.1.2 of Chapter 4.

Table 2-6: Demand Response Auction Results in December 2015 (MW, $/MW-day)

Description

Table 1-6 summarizes the results of the IESO's inaugural Demand Response (DR) Auction, completed in December 2015 for the subsequent summer (May 1, 2016 to October 31, 2016) and winter (November 1, 2016 – April 30, 2017) commitment periods. In general, DR consists of programs that encourage customers to reduce demand during times of tight supply conditions. DR is meant to reduce the total peak demand, or be used at other times to assist with maintaining reliability, as an alternative to calling on generators to produce more energy. As specified by the capacity obligation within each zone, resources committed through the DR auction are available to provide relief by reducing their consumption when called upon. Successful resources from the DR auction receive the auction clearing price for each MW of DR capacity.[36]

Zone	Summer Commitment Period (May 1, 2016 - Oct 31, 2016)		Winter Commitment Period (Nov 1, 2016 - Apr 30, 2017)	
	Capacity Obligation (MW)	Auction Clearing Price ($/MW-day)	Capacity Obligation (MW)	Auction Clearing Price ($/MW-day)
BRUCE	-	-	-	-
EAST	24.7	378.21	25.4	359.87
ESSA	13.7	378.21	13.8	359.87
NIAGARA	15.9	348.45	15.9	332.71
NORTHEAST	56.3	378.21	56.3	359.87
NORTHWEST	51	378.21	50	359.87
OTTAWA	10.8	378.21	11.2	359.87
SOUTHWEST	40	378.21	55.3	359.87
TORONTO	159.4	378.21	159.2	359.87
WEST	19.7	378.21	16.6	359.87
Total MW	**391.5**	**-**	**403.7**	**-**
Weighted Average Price	**-**	**377.00**	**-**	**358.80**

[36] See Chapter 3 for an in-depth explanation of the DR auction process.

Relevance

The DR Auction is part of the IESO's transitional program to migrate the procurement of demand response from previous multi-year, contracted programs into a more competitive, near-term market mechanism within the IESO-administered markets. Instituting the DR Auction is viewed by the IESO as a foundational step to introduce a market-based mechanism to procure capacity, with the aim to allow for the entry of new, cost-effective demand response providers, enable system flexibility, and evolve the demand response sector to eventually compete with conventional forms of capacity such as supply or import resources. The DR Auction is also one of the key instruments the IESO is using to work towards the policy goal set forth in the 2013 Long Term Energy Plan of reducing peak demand by 10% in 2025.

Commentary

As Ontario has 10 electrical zones with varying supply and demand conditions, the auction took place on a zonal level by creating limits for the amount of DR procured in each zone. Zones with more generation than load would require less DR, while zones with more load than generation can have DR playing a greater role in matching supply and demand. For these reasons, Toronto was the zone with the greatest capacity obligation, holding 40.7% and 39.4% of the total capacity obligation in the summer and winter commitment periods, respectively. There was no cleared capacity in Bruce because no participant submitted offers into the auction. See section 3.2 of Chapter 4 for an in-depth discussion of the DR auction.

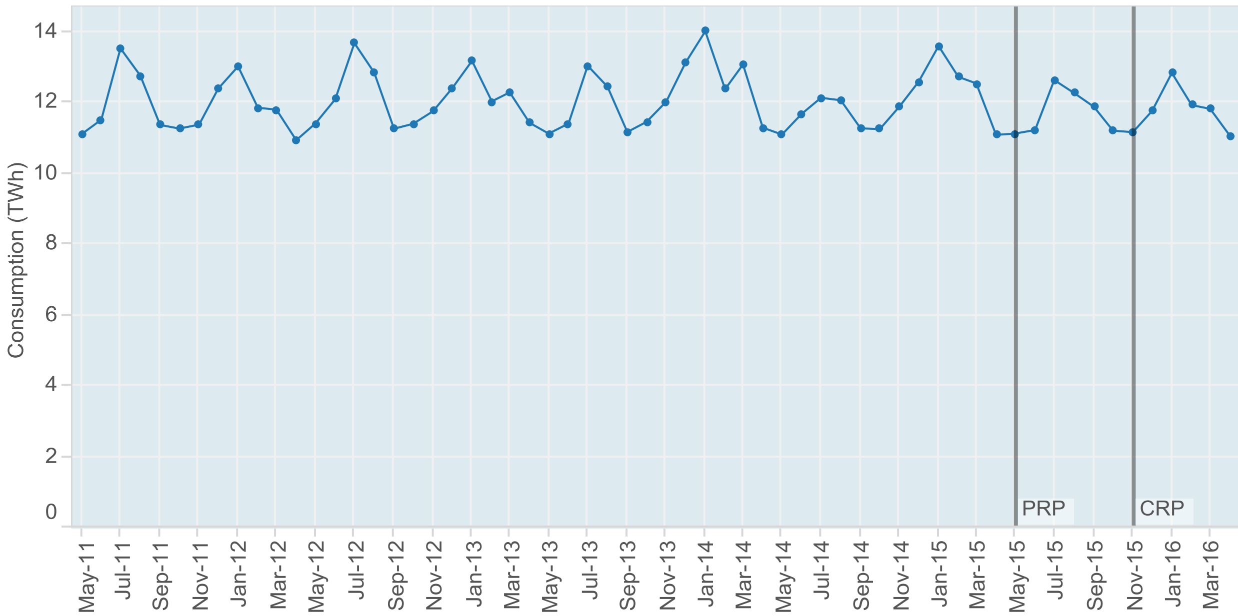
2 *Demand*

This section discusses Ontario energy demand for the Current Reporting Period relative to previous years.

Figure 2-20: Monthly Ontario Energy Demand
May 2011 – April 2016
(TWh)

Description:

Figure 2-20 presents energy consumption by all Ontario consumers in each month in the past 5 years. The figure represents Ontario demand, which includes demand satisfied by behind-the-meter (embedded) generators.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Ontario monthly consumption information shows seasonal variations in consumption and year-to-year changes in consumption patterns.

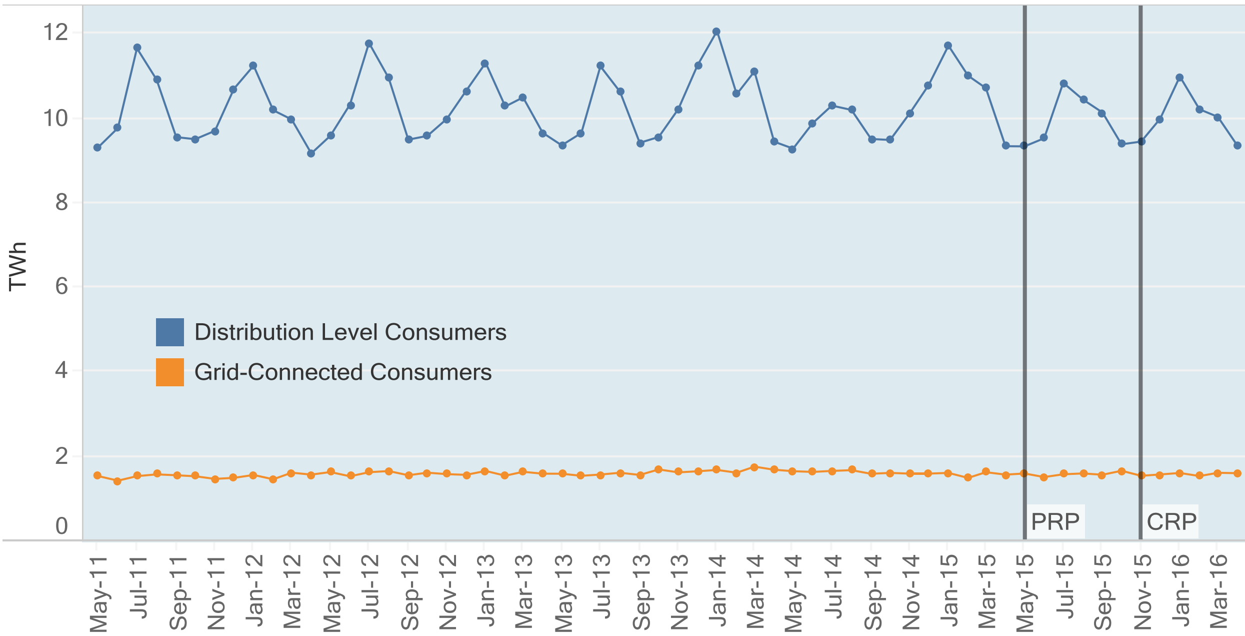
Commentary and Market Consideration:

The peak consumption during the Current Reporting Period was 12.82 TWh, which was lower than the peak consumption during the Winter 2015 and Winter 2014 Periods. In fact, monthly demand in the Current Reporting Period was less than it was for each corresponding month in the Winter 2015 Period. The relatively mild winter weather contributed to the reduction in demand.

Figure 2-21: Monthly Total Energy Withdrawals, Distributors and Wholesale Loads May 2011 – April 2016 (TWh)

Description:

Figure 2-21 charts the demand of two categories of consumers: market participants that are directly connected to the IESO-controlled grid other than distributors (Grid-Connected Consumers), and consumers connected to distribution systems (Distribution Level Consumers).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The breakdown of consumers into these two categories helps identify their respective monthly demand profiles.

Commentary and Market Consideration:

Seasonal changes in Ontario demand are attributed almost entirely to Distribution Level Consumers, which include residential, small and medium commercial, and small industrial loads. Demand from Grid-connected consumers, a group primarily composed of industrial loads and large commercial consumers, exhibit little of the seasonality evident of distribution-level consumption.

3 *Supply*[37]

During the fourth quarter of 2015 and the first quarter of 2016, 549.7 MW of nameplate generating capacity completed commissioning and was added to the IESO-controlled grid's total installed generator capacity. This new grid-connected capacity consisted of wind (409.7 MW) biomass (40 MW) and solar (100 MW) generation. At the end of the first quarter of 2016, grid

[37] For a more detailed examination of the medium-term supply capacity in Ontario, see the IESO's 18-month outlook, released in March 2016 and available at: http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18-month-outlook--2016mar.zip

connected generation capacity totalled 35,731 MW, consisting of nuclear (12,978 MW), gas-fired (9,942 MW), hydroelectric (8,432 MW), wind (3,643 MW), biofuel (495 MW) and solar generation (240 MW)[38].

During the fourth quarter of 2015 and the first quarter of 2016, 130 MW of nameplate IESO contracted generating capacity was added at the distribution level. This new distribution-level capacity (or 'embedded' capacity) consisted of solar (110 MW), wind (14 MW), biofuel (1 MW), hydroelectric (5 MW), and gas-fired and combined heat and power (4 MW). At the end of the first quarter of 2016, IESO contracted embedded capacity totalled 2,970 MW, consisting of solar (1,876 MW), wind (498 MW), hydroelectric (269 MW), gas-fired and combined heat and power (213 MW), biofuel (108 MW) and energy from waste (10 MW).[39]

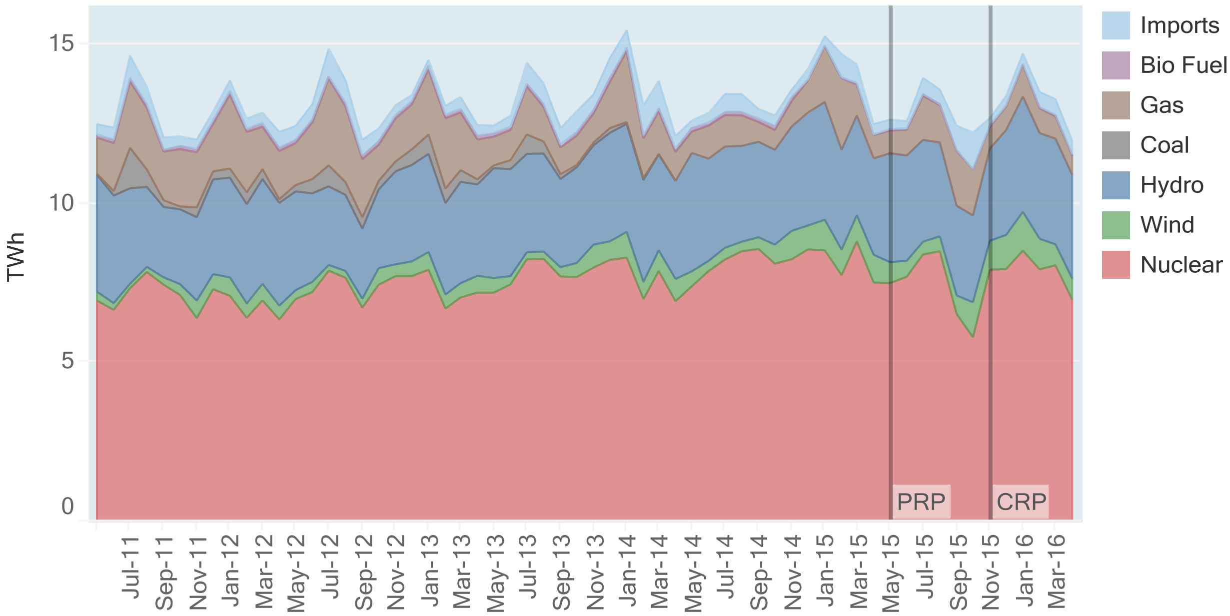
Figure 2-22: Resources Scheduled in the Real-Time Market (Unconstrained) Schedule by Reporting Period May 2011 – April 2016 (TWh)

Description:

Figure 2-22 illustrates the cumulative share of energy in the real-time unconstrained schedule for the past five years by resource or transaction type: wind, coal, gas-fired, hydroelectric, nuclear, and imports. Solar and biofuel are excluded from the figure as they contribute minimally to the total grid-connected resources scheduled in real-time.

[38] Capacity totals were obtained from the Ontario Energy Board's quarterly Ontario Energy Reports. Added capacity totals were calculated from 2015's Q1, Q2 and Q3 reports, which can be found at: http://www.ontarioenergyreport.ca/index.php

[39] Embedded capacity totals were obtained from the Ontario Energy Board's quarterly Ontario Energy Reports. Added embedded capacity totals were calculated from 2015's Q1, Q2 and Q3 reports, which can be found at: http://www.ontarioenergyreport.ca/index.php.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure displays the evolution of Ontario's changing mix of real-time energy supply. Changes in the resources scheduled may be the result of a number of factors, such as changes in energy policy or seasonal variations (for example, during the spring snowmelt or 'freshet' when hydroelectric plants have an abundant supply of fuel).

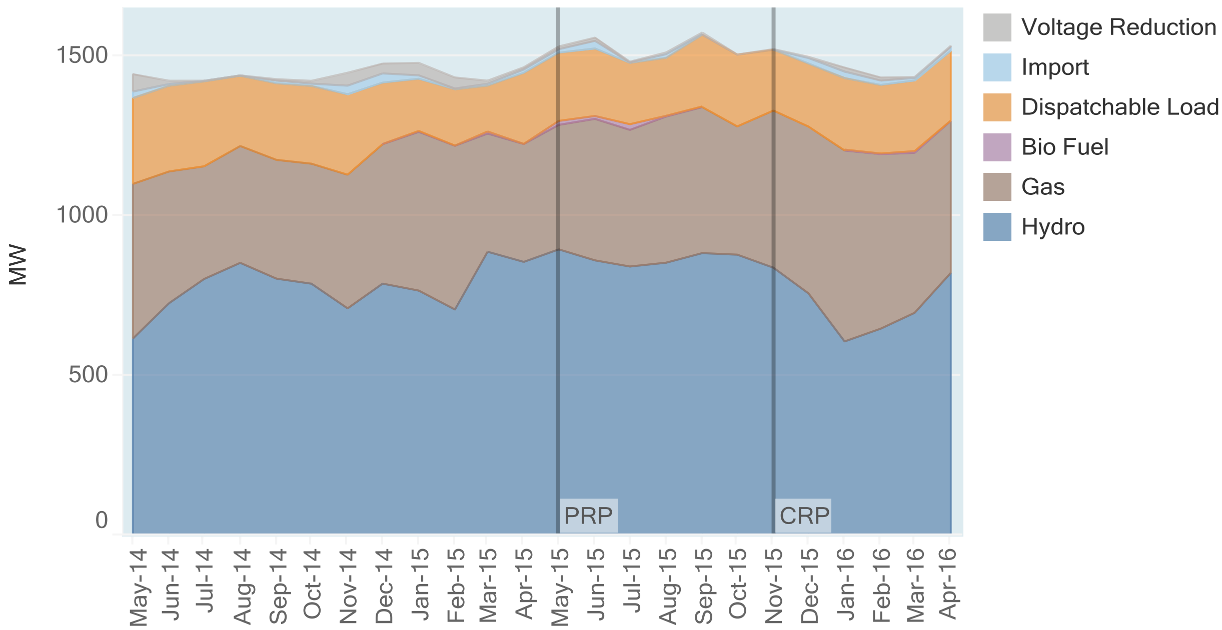
Commentary and Market Considerations:

Nuclear and hydroelectric resources continued to be the main sources of generation in Ontario. Wind resources were scheduled to produce more than gas-fired facilities for the first time (5.5 TWh for wind, 4.5 TWh for gas) in the Current Reporting Period.

Figure 2-23: Average Hourly Operating Reserve Scheduled by Resource or Transaction Type May 2014 – April 2016 (MW per hour)

Description:

Figure 2-23 plots the average hourly amount of OR in the unconstrained schedule for the past two years by resource or transaction type: hydroelectric, gas-fired, imports, dispatchable loads and voltage reduction.[40] Changes in the total average hourly operating reserve scheduled reflect changes in the OR quantity requirements.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure reflects the evolution in Ontario's changing mix for OR supply as well as changes in the OR requirement over time. Changes in scheduled OR may result from a variety of factors such as changes in energy policy or seasonal variations, while changes to the OR requirement may result from changes in grid configuration and outages, among other factors. [41]

Commentary and Market Considerations:

The amount of OR scheduled in the Current Reporting Period (6.4 TWh) decreased relative to the Previous Reporting Period (6.7 TWh) but slightly increased relative to the 2015 Winter Period (6.3 TWh): this corresponded to changes in the total OR requirement between monitoring periods. Factors such as increased power flows on a major 500 kV circuit – connecting supply in the Northeast to demand in the South – and an instance of nuclear commissioning tests in April

[40] The IESO inserts standing offers in the OR offer stack that represent the IESO's ability to use 3% and 5% voltage reductions or forego the 30-minute OR requirement (under specific conditions) to meet OR needs. The offers have a pre-defined price and quantity and are only used in real-time, never in pre-dispatch. Voltage reduction is an out-of-market control action taken by the IESO when the market cannot provide enough supply to meet forecasted demand and reserve requirements.

[41] The total energy available from the 10-minute OR market must be enough to cover the single largest contingency in Ontario's electricity grid, with at least 25% of that energy available as 10-minute spinning reserve. The total energy available from the 30-minute OR market must be enough to cover half the second largest contingency on Ontario's grid.

2016 have contributed to the total OR requirement increasing beyond 1500 MW for more than 50% of all hours in the Current Reporting Period. In contrast, the Previous Reporting Period had approximately 90% of all such hours: this is likely attributed to seasonal freshet that increased the flow of hydroelectric power from the Northeast during May and June 2015. Between the Winter 2015 Period and Current Reporting Period, the slight increase in total OR requirement is likely attributed to anticipated changes in the operational profile of various nuclear facilities – a notable example being the nuclear commissioning tests that took place in April 2016.

The share of OR provided by hydro went down to an average of 48.9% during the Current Reporting Period compared to 56.8% from the Previous Reporting Period and 54.0% from the Winter 2015 Period. The share of OR provided by gas went up to 35.4% compared to 28.1% from the Previous Reporting Period and 30.0% from the Winter 2015 Period. The remainder of OR were supplied by voltage reduction, dispatchable loads, and imports.

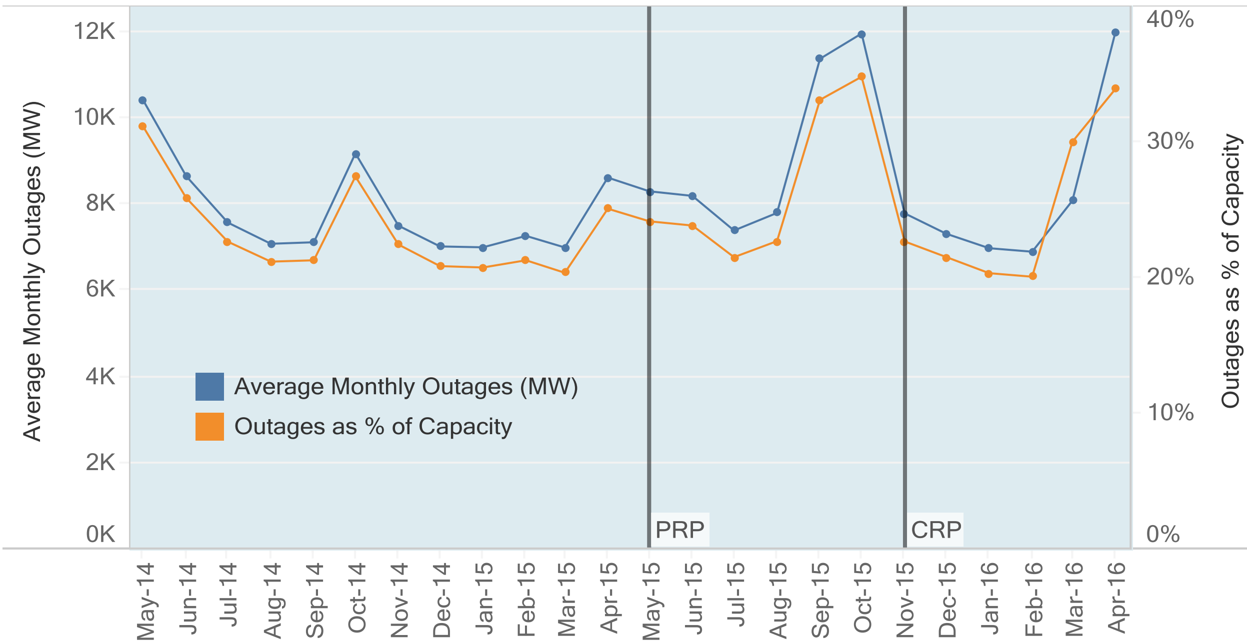
Figure 2-24: Unavailable Generation Relative to Installed Capacity May 2014 – April 2016 (% of capacity) [42]

Description:

Figure 2-24 plots the monthly averages of the hourly sums of unavailable generation capacity due to planned and forced (i.e. unforeseen) outages and derates, along with unscheduled capacity from intermittent, self-scheduling and transitional generators and constrained generation capacity due to operating security limits, as a percentage of total grid-connected installed generation capacity from May 2014 – April 2016.[43]

[42] In Previous Panel Reports, Figure 1-24 reported planned and forced outages and derates relative to capacity. The Panel has decided to report on all unavailable generation capacity. As such, the data reported in Figure 1-24 will not align with similar data published in previous Panel Reports for the period of November 2013 through April 2015. The Panel did this intentionally as it has revised the methodology by which it reports on unavailable generation capacity to also include unscheduled capacity from self-scheduling resources and capacity that is made unavailable due to security limits on the high-voltage grid, in addition to planned and forced outages and derates.

[43] Unavailable generation capacity data was obtained from System Status Reports published daily by the IESO. A simple monthly average was calculated using the most recently reported totals for each hour of each trade date. Daily, weekly and monthly market summaries published by the IESO can be found here: http://www.ieso.ca/Pages/Power-Data/Market-Summaries-Archive.aspx.



*PRP: Previous Reporting Period. CRP: Current Reporting Period

Relevance:

Statistics regarding unavailable generation capacity provide an overview of how much of the time facilities in the province were able to provide supply, a key factor in the determination of market prices.

Commentary and Market Considerations:

Until March and April 2016, average monthly outages had decreased significantly from the Previous Reporting Period. The spike in outages in March and April are primarily attributed to nuclear refurbishments and refueling procedures that accounted for 65% of all unavailable capacity. Furthermore, planned outages with hydroelectric generation stations, for reasons such as transmission upgrades, accounted for 24% of all unavailable capacity.

4 *Imports, Exports and Net Exports*

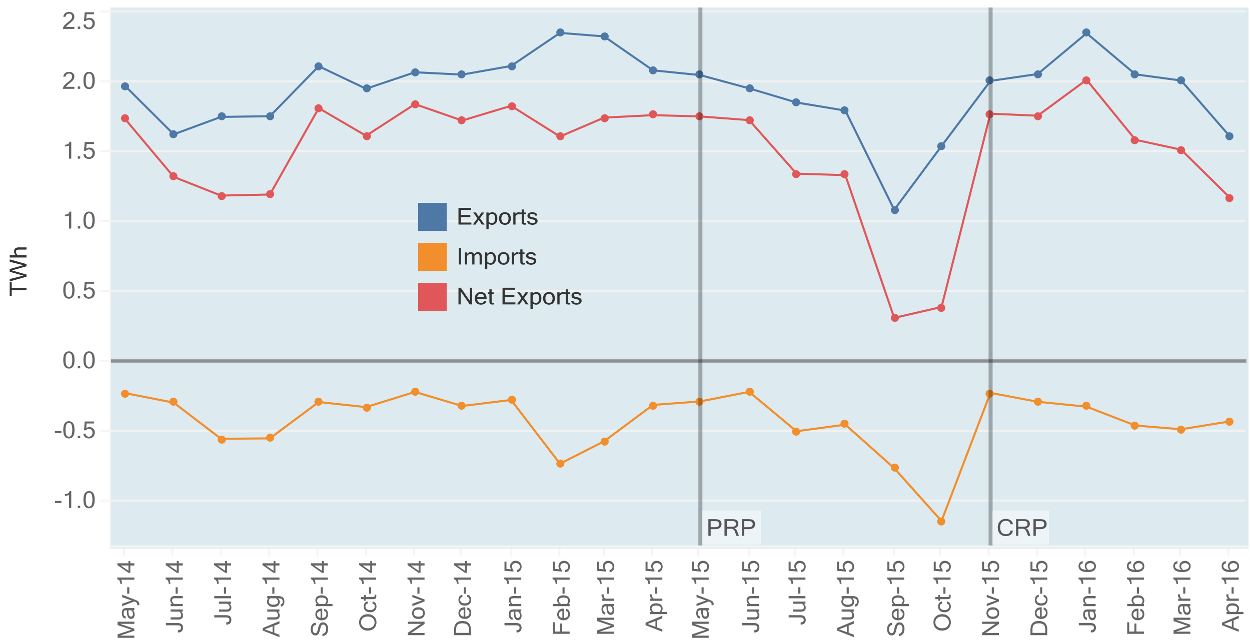
The data used in this section are based on the unconstrained schedules as these directly affect market prices. The unconstrained schedules may not reflect actual power flows.[44]

[44] Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not provide information on intertie congestion prices or the Ontario uniform price (either in pre-dispatch or in real-time).

Figure 2-25: Total Monthly Imports, Exports & Net Exports (Unconstrained Schedule) May 2014 – April 2016 (TWh)

Description:

Figure 2-25 plots total monthly energy imports, exports and net exports from May 2014 to April 2016. Exports are represented by positive values while imports are represented by negative values.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Imports and exports play an important role in determining supply and demand conditions in the province, and thus affect the market price. Tracking net export transactions over time provides insight into supply and demand conditions in Ontario relative to neighbouring jurisdictions. Periods of sustained net exports, such as the Current Reporting Period, indicate times of relative energy surplus in Ontario, while sustained periods of net imports, such as during the mid-2000s, indicate periods of relative scarcity.

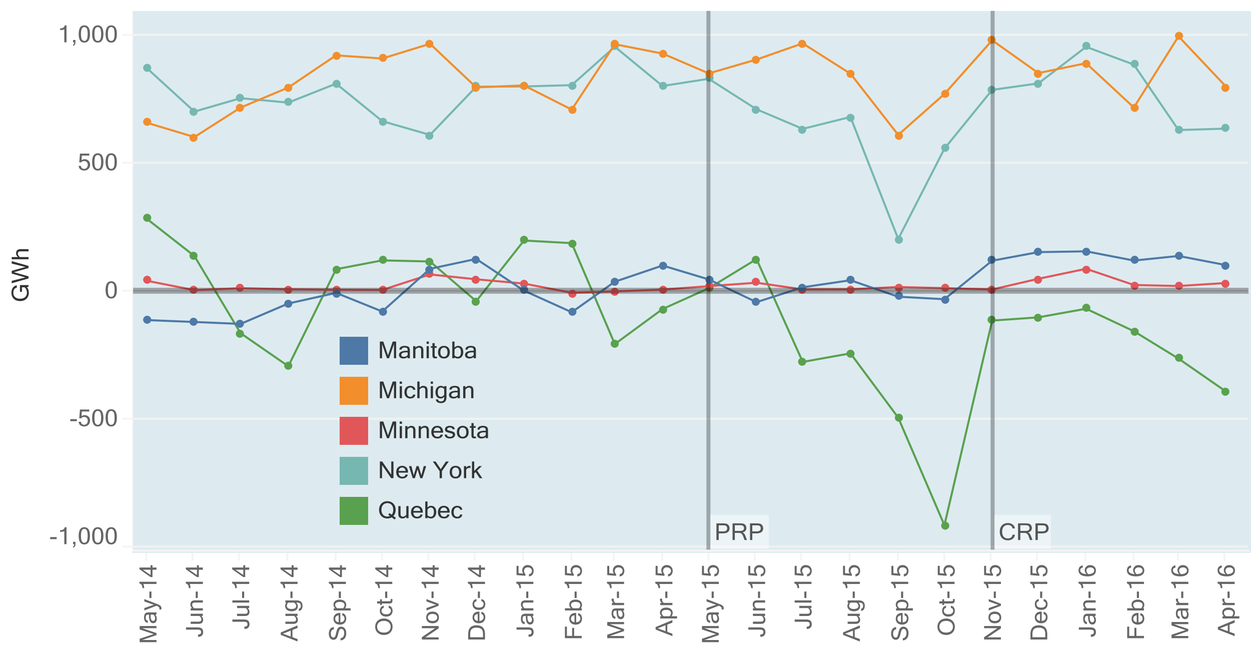
Commentary and Market Considerations:

There were higher net exports in the Current Reporting Period, which totalled 9.76 TWh, compared to the previous reporting Period, which totalled 6.80 TWh. The combination of low demand, low HOEP, and a weak Canadian dollar has contributed to stronger net exports.

Figure 2-26: Net Exports by Interface Group
May 2014 – April 2016
(GWh)

Description:

Figure 2-26 presents a breakdown of net energy exports from May 2014 to April 2016 to each of Ontario's five neighbouring jurisdictions: Manitoba, Michigan, Minnesota, New York and Quebec. Net exports are represented by positive values while net imports are represented by negative values.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure shows how Ontario's energy trade evolves over time with each external jurisdiction.

Commentary and Market Considerations:

Net exports increased in every interface (except Québec) compared to previous monitoring periods, which was incentivized by the lower Ontario HOEP in the Current Reporting Period. The New York intertie experienced the largest increase in net exports by 1.09 TWh. While Québec's net imports dropped by 0.69 TWh in the Current Reporting Period, it remained a net importer across all months, totalling 1.11 TWh.

Table 2-7: Average Monthly Export Failures by Interface Group and Cause May 2015 – October 2015 & November 2015 – April 2016 (GWh and %)

Interface Group	Average Monthly Exports GWh		Average Monthly Export Failure and Curtailment GWh				Export Failure and Curtailment Rate %			
			ISO-Curtailment		MP-Failure		ISO-Curtailment		MP-Failure	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	386.3	289.1	1.8	1.5	8.3	5.9	0.5	0.5	2.1	2.0
Michigan	348.1	333.8	1.5	1.2	3.2	4.7	0.4	0.4	0.9	1.4
Manitoba	79.9	37.4	2.6	3.2	16.3	11.7	3.2	8.5	20.4	31.1
Minnesota	6.0	8.2	0.2	0.4	0.2	0.2	2.7	5.0	3.7	2.9
Quebec	93.2	92.5	4.2	1.4	1.3	0.4	4.5	1.5	1.4	0.4

Description:

Table 2-6 reports average monthly export curtailments and failures over the Current and Previous Reporting Periods by interface group and cause. The failure and curtailment rates are expressed as a percentage of total (constrained) exports over each interface, excluding linked wheel transactions.[45]

Relevance:

Curtailment (ISO Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Failure (MP Failure), on the other hand, refers to a transaction that fails due to a failure on the part of a market participant (such as a failure to obtain transmission service).

MP Failures and ISO Curtailments in respect of exports reduce demand between the hour-ahead pre-dispatch schedule and real-time. These short-notice changes in demand can lead to a sub-optimal level of intertie transactions given the market prices that prevail in real-time, and may contribute to SBG conditions. The IESO may dispatch down domestic generation or curtail imports to compensate for MP Failures or ISO Curtailments.

[45] A linked wheel transaction is one in which an import and an export are scheduled in the same hour, thus wheeling energy through Ontario.

Commentary and Market Considerations:

Average export failures caused by market participants increased in volume on the Manitoba intertie; such failures accounted for 20% of export transactions. Manitoba continues to be an outlier with respect to the percentage and absolute volume of monthly exports that are curtailed due to MP failure.

Table 2-8: Average Monthly Import Failures by Interface Group and Cause May 2015 – October 2015 & November 2015 – April 2016 (GWh and %)

Interface Group	Average Monthly Imports GWh		Average Monthly Import Failure and Curtailment GWh				Import Failure and Curtailment Rate %			
			ISO-Curtailment		MP-Failure		ISO-Curtailment		MP-Failure	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	1.4	13.1	0.0	0.1	0.1	0.4	0.6	0.6	3.8	3.0
Michigan	1.2	5.4	0.2	0.1	0.4	0.6	16.6	1.6	34.7	10.4
Manitoba	34.8	21.0	5.9	3.5	0.3	0.1	16.9	16.8	0.8	0.5
Minnesota	8.2	1.4	0.9	0.1	0.7	0.1	11.5	4.9	8.8	4.2
Quebec	85.7	136.1	2.6	5.9	0.1	0.5	3.1	4.3	0.1	0.3

Description:

Table 2-7 reports average monthly import failures and curtailments over the Current and Previous Reporting Periods by interface group and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.

Relevance:

MP Failures and ISO Curtailments in respect of imports represent a reduction in supply between the hour-ahead pre-dispatch schedule and real-time. This change in supply can lead to a sub-optimal level of intertie transactions and may contribute to increases in price. The IESO may dispatch up domestic generation or curtail exports to compensate for MP Failures and ISO Curtailments.

Commentary and Market Considerations:

Except Québec, the percentage of ISO Curtailments and MP Failures increased at all interfaces relative to the Previous Reporting Period, albeit on a relatively low volume of imports

Chapter 3: Analysis of Anomalous Market Outcomes

1 *Introduction*

This chapter examines the market outcomes associated with anomalous prices and payments during the Current Reporting Period, from November 1, 2015 to April 30, 2016.

Typically, the Panel's analysis of anomalous events focusses on high and negative Hourly Ontario Energy Prices (HOEP), as well as instances of high uplift, such as Congestion Management Settlement Credit (CMSC) payments, Intertie Offer Guarantee (IOG) payments, and payments made through the IESO's Real-Time Generation Cost Guarantee (RT-GCG) program and the Day-Ahead Commitment Program (DACP). Payments made through the DACP are referred to as Day-Ahead Production Cost Guarantee (DA-PCG) payments. All of the aforementioned payments are recovered from consumers through uplift charges.

In the past, the Panel has defined anomalous events using several thresholds, such as the HOEP being greater than \$200/MWh or daily CMSC payments being in excess of \$1 million. Table 3-1 displays the number of events that exceeded the Panel's thresholds during the Current Reporting Period.

***Table 3-1: Summary of Anomalous Events
November 2015 – April 2016
(Number of Events)***

Anomalous Event Threshold	Number of Events
HOEP > \$200	5
HOEP ≤ \$0	1,427
Energy CMSC > \$1 million/day	0
Energy CMSC > \$500,000/hour	0
OR Payments > \$100,000/hour	5
IOG > \$1 million/day	0
IOG > \$500,000/hour	0

During the Current Reporting Period, there were five hours when the HOEP was greater than \$200/MWh; during these five hours there were also operating reserve (OR) payments in excess of \$100,000. Having analyzed these hours, the Panel has concluded that they were largely the result of variable generation shortfall and demand forecast errors. In these hours, ample supply conditions in pre-dispatch resulted in relatively low prices and few gas-fired facilities being committed to generate. With few gas-fired facilities online to provide relatively inexpensive ramping capability and OR, the system had limited ability to absorb the loss of variable generation and excess demand in real time, resulting in high HOEP and OR payments. High prices related to limited ramp capability were examined in detail in the Panel's November 2016 Monitoring Report.[46] In one of the five aforementioned hours, the supply shortfall and excess demand conditions were exacerbated by an unforeseen nuclear outage.

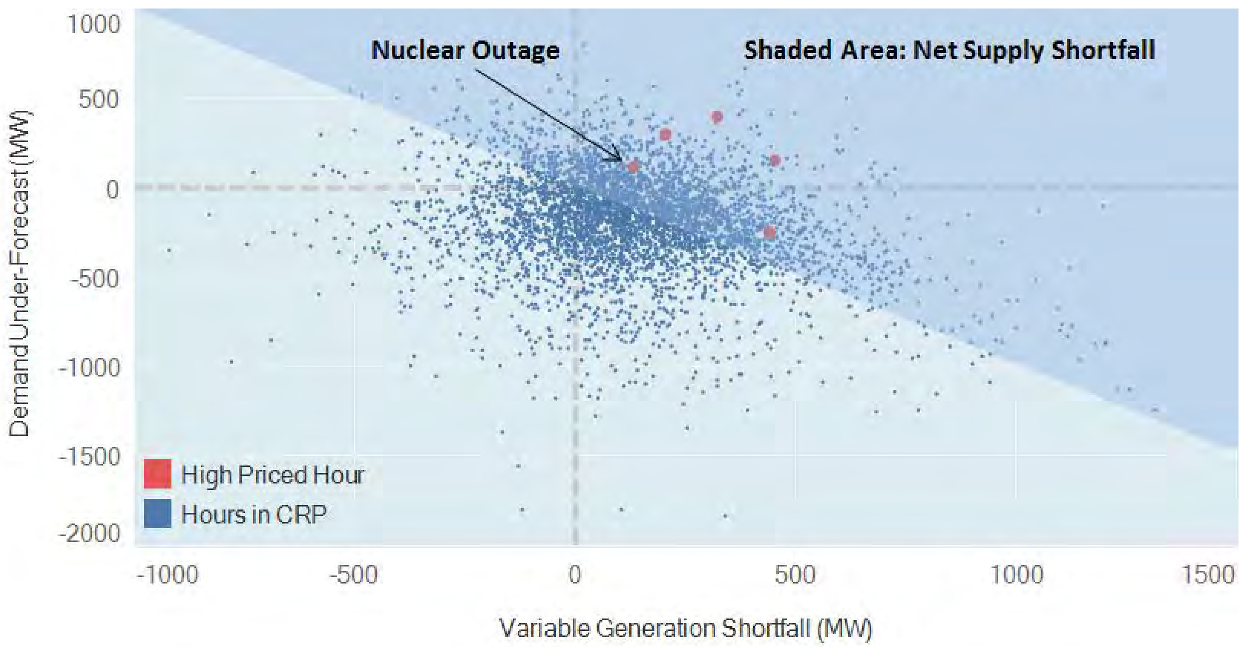
There were no days or hours during the Current Reporting Period that exceeded the Panel's CMSC or IOG thresholds.

There were 1,427 hours when HOEP was non-positive: an all-time high number of non-positive hours during a 6-month reporting period. Non-positive HOEPs are the result of increasingly common conditions, such as: low Ontario demand, abundant supply offered at negative prices, and failed export transactions, among other causes. The Panel examines the conditions surrounding non-positive hours in greater detail in section 3 of this chapter.

As has been described above, a high or low price, or a large uplift payment, does not necessarily indicate that there was something amiss; the regularity with which variable generation shortfall and/or demand under-forecast are contributors to high HOEP events is one such example. Figure 3-1 shows that all five high price hours in the Current Reporting Period, marked in red, occurred during net supply shortfall (defined as hours in which the sum of demand under-forecast and variable generation shortfall are positive, creating tighter supply conditions in real-time relative to pre-dispatch).

[46] See pages 69 –71 of the Panel's November 2016 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2015-Oct2015_20161117.pdf

Figure 3-1: HOEP by Net Supply Conditions
November 2015 – April 2016
(MW)



Anomalous events (market outcomes that fall outside predicted patterns and norms) do not necessarily result in high prices or large uplift payments, nor are they necessarily confined to a single hour or day. In this chapter, the Panel has expanded its analysis of anomalous events beyond those which meet or exceed pre-determined thresholds. Other criteria for assessing events include: the appropriateness of the market outcome relative to the Market Objective[47] and the Market Rules; the novelty and frequency of an unexpected event, as well as the relevance of the outcome to current IESO initiatives and stakeholder engagements. The Panel's approach will be informed by the historic thresholds, but will broaden the analysis to include other relevant events as appropriate.

2 *Analysis of Anomalous Events*

In the sections that follow, the Panel reports on three anomalous events that occurred during the Current Reporting Period. These events resulted in inappropriate payments or outcomes related to: dispatchable loads in the OR markets, ramp-down CMSC payments, and export failures.

[47] The Market Objective of the IESO-administered markets is to promote an efficient, competitive, and reliable market for the wholesale sale and purchase of electricity and ancillary services in Ontario.

2.1 *Dispatchable Loads and Unavailable Operating Reserves in February 2016*

Relevance

From January 2010 to April 2016, the Panel estimates that dispatchable loads (DLs) received approximately $12.5 million in OR payments for reserves that they were incapable of providing. Such instances are of concern, not only for the significant inappropriate payments themselves, but also for the corresponding reliability issues. To highlight these concerns, the Panel analyzes one such event that occurred in the ten-minute OR markets during hour ending (HE) 19 on February 21, 2016.

Analysis

OR is standby capacity intended to respond to, and recover from, a contingency on the grid. Such a contingency could take the form of a sudden, unexpected increase in demand, a forced outage of generation or transmission equipment, or significant dispatch deviations from generators or DLs, among other possibilities. Resources scheduled to provide standby capacity in the ten-minute OR market must provide the entirety of that capacity within ten minutes of receiving an OR activation, and must be able to provide the activated capacity for at least one hour.[48] When a DL's standby capacity is activated to help recover from a contingency, the DL provides relief by reducing its consumption. To be able to provide the required relief (and fulfill its OR activation), a DL must be consuming at least the activation amount prior to being activated.

Table 3-2 summarizes the dispatch schedules, actual MW consumption, OR price, and corresponding OR payments for two DLs on HE 19 of February 21, 2016.

[48] Refer to the Market Rules, Chapter 5 Appendices, Section 1.2

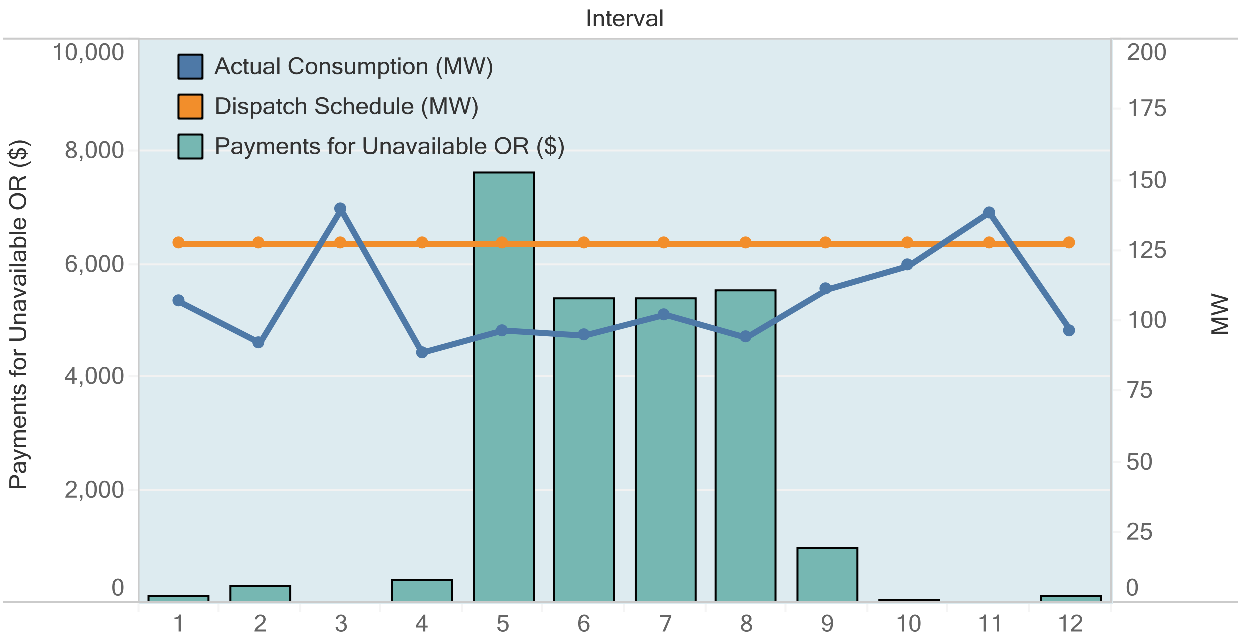
Table 3-2: Participation of Two Dispatchable Loads in the Ten-Minute OR Markets February 21, 2016, HE 19

Interval	OR Schedule (MW)	Actual Consumption (MW)	Unavailable OR (MW)[49]	OR Price ($/MWh)	Payment for Unavailable OR ($)
1	127	107	36	30	91
2	127	92	43	75	270
3	127	139	0	91	0
4	127	89	48	96	386
5	127	96	46	2,000	7,613
6	127	95	32	2,000	5,403
7	127	102	32	2,000	5,386
8	127	94	33	2,000	5,523
9	127	111	29	396	956
10	127	119	16	30	39
11	127	138	0	30	0
12	127	96	37	30	93
Total	-	-	-	-	**25,760**

As illustrated in Figure 3-2, during numerous intervals within the hour these DLs consumed less than their scheduled OR standby capacity. Had these DLs been activated to recover from a contingency, they would have been unable to provide the relief they were paid for.

[49] Because Table 3-2 aggregates the data of two DLs, the unavailable OR in a given interval is not necessarily equal to the difference between the total OR schedule and the total consumption shown in the table. The OR schedule represents the maximum OR a DL can provide, therefore any over consumption by one DL does not offset the under consumption of another when determining how much OR is available.

Figure 3-2: OR Schedule, Energy Consumption, and Excess Compensation for Two Dispatchable Loads on February 21, 2016, HE 19 (MW, $)



In totality these resources were compensated for 29 MWh[50] of OR they were unable to provide. This hour experienced the highest average ten-minute OR price of the Current Reporting Period ($1,050/MW), signalling a premium on reliability. Since DLs are compensated according to their OR schedule, not the OR they were able to provide, the two DLs received $25,760 for OR that they were incapable of providing.

DLs scheduled for ten-minute OR were capable of providing the entirety of their OR schedule in only 9.6% of intervals during the Current Reporting Period. In the remaining 90.4% of intervals, DLs had an average OR schedule of 122 MW, but only consumed an average of 57 MW. Accordingly, there was an average of 65 MW of unavailable OR from DLs, or approximately 6.5% of the average ten-minute OR requirement. This outcome is inappropriate: not only were the DLs potentially compromising the reliability of the grid by operating in a manner which rendered them unable to meet their OR obligation, but they were compensated for such behaviour. This is a recurring outcome (across several DLs) that has resulted in approximately

[50] This number is calculated by adding the unavailable OR values in each interval from Table 3-2 and dividing the sum by 12 to generate the corresponding MWh value.

$12.5 million being paid for scheduled OR that were not actually provided (from January 2010 through April 2016).

The Panel recognizes that provisions exist in the Market Rules to recover payments made to DLs for unavailable OR. While the Panel encourages the IESO to pursue any and all available avenues for recovering such payments, the IESO should also pursue a more fundamental solution that prevents the payments from being made in the first instance.

Recommendation 3-1:
The IESO should take steps to ensure that dispatchable loads are only compensated for the amount of operating reserve they were capable of providing in real-time. More fundamentally, the IESO should explore options for ensuring unavailable OR is not scheduled in the first instance.

2.2 *Ramp-Down CMSC Payments for a Gas-Fired Generator on January 4, 2016*

Relevance

A generator signals its intent to come offline at the end of its run by raising its energy offer price above the local nodal price, thus becoming uneconomic in the constrained sequence. Due to the three-times ramp rate assumption used in the unconstrained sequence,[51] a generator's unconstrained schedule ramps down faster than its constrained schedule. As a result, there is a divergence between the two schedules during the ramp-down period, resulting in constrained-on CMSC payments.

In past reports, the Panel has highlighted the inappropriate nature of CMSC payments caused by ramping, and recommended that the IESO eliminate them; CMSC is not intended to provide a revenue stream for generators that take a voluntary action.

The IESO conducted a stakeholder engagement on the matter, introducing Market Rule Amendment MR-00414 to mitigate CMSC payments caused by ramping. While the rule was

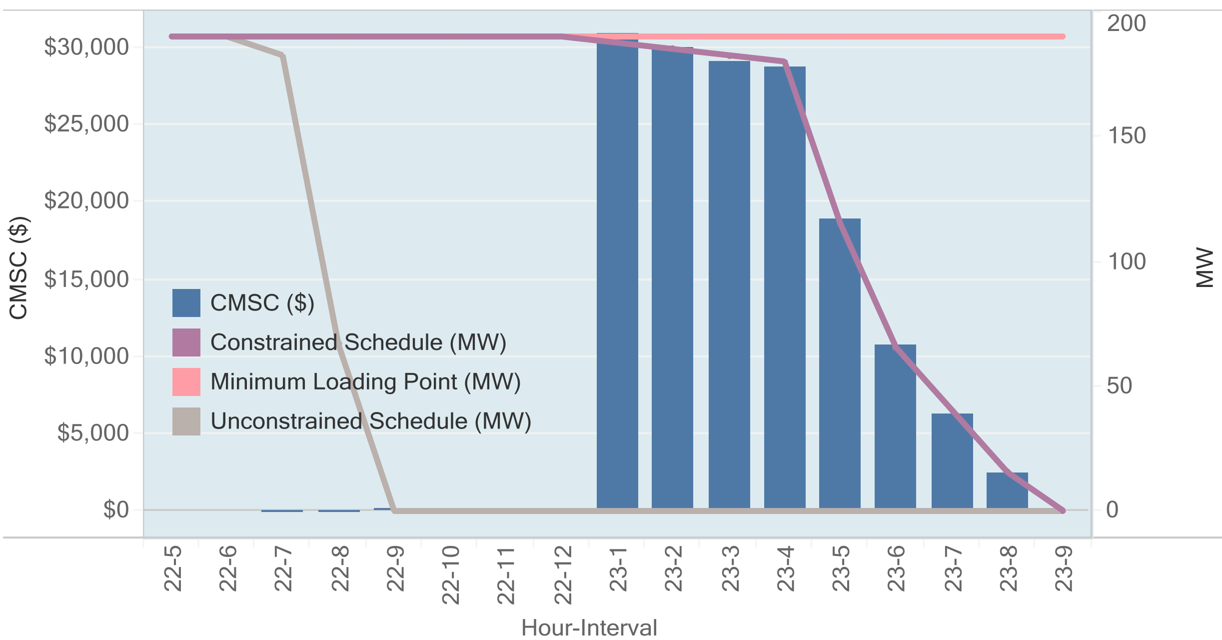
[51] The "three-times ramp rate assumption" refers to the IESO's unconstrained dispatch algorithm's assumption that a generator can ramp down three times faster than is technically feasible. The constrained dispatch algorithm must respect the physical limitations of generators in order to produce a feasible schedule, and thus does not employ the three-times ramp rate assumption. The result is a divergence between a generator's constrained and unconstrained schedules any time the unit is ramping, which results in CMSC payments.

approved by the IESO Board of Directors on June 24, 2015,[52] it was not implemented by the IESO until a year and half later on December 8, 2016. To highlight the ramp-down CMSC payments that were ongoing during the period between the rule approval and its implementation, the following section examines the operation of a gas-fired facility in January 2016.

Analysis

On January 4, 2016, a gas-fired facility offered its full capacity at $2,000/MWh in HE 23 in order to signal its intent to ramp down and come offline. As illustrated in Figure 2-3, the facility ramped down from interval 1 to 8 in HE 23 and generated approximately $160,000 in CMSC payments.

Figure 3-3: Gas-Fired Generator's Ramp-Down Profile and CMSC
January 4, 2016
(MW, $)



The CMSC payments were self-induced by the market participant's decision to come offline and exacerbated by the participant's choice of a $2,000/MWh offer price; which was well in excess of the price required to ensure a ramp down was achieved.

[52] For more information on Market Rule 414, see the IESO's SE-111 stakeholder webpage, available at: http://www.iemo.com/Pages/Participate/Stakeholder-Engagement/SE-111.aspx

While the IESO Board of Directors had already approved a Market Rule to limit ramp-down CMSC payments, the effective date of the Market Rule was contingent on the implementation of the required IT system changes, which were not yet in place.[53] Had the rule been put in effect when passed, ramp-down CMSC payments for the gas-fired facility would have been reduced from $160,000 to $4,000.

The Panel estimates that CMSC payments caused by ramping would have been reduced by $1.9 million market wide from June 25, 2015 to December 7, 2016 had the Market Rule amendment been effective from the date the amendment was approved.

The Panel understands that the implementation of the Market Rule amendment was delayed due to the relative complexity of the required solution. The decision not to make the market rule amendment effective immediately or to recommend retroactive adjustment was also due to the intricacy of the IT solutions. The Panel recognizes that while the implementation of the Market Rule amendment represented a complex IT process, that relative difficulty should not preclude the IESO from making retroactive adjustments pursuant to the appropriate Market Rule, which in this case could have clawed back approximately $1.9 million.

The Panel believes that the IESO should make all reasonable efforts to allow future Market Rule amendments to be effective immediately upon approval by the Board of Directors. This would allow the IESO to retroactively apply adjustments in accordance with the Market Rules, regardless of implementation constraints.

2.3 *Export Failures on the New York Intertie on February 20, 2016*

Relevance

Transmission lines can only accommodate a certain amount of electricity flow at a given time; this limit is referred to as the scheduling limit. Congestion occurs when the quantity of electricity scheduled to flow over the transmission line exceeds the scheduling limit.

When an intertie becomes congested, the Intertie Zonal Price (IZP) – the price at which intertie traders are settled – will differ from the Market Clearing Price (MCP). The IZP will be higher

[53] For more information on the IESO Board of Directors decision on MR-00414, see the Market Rule Amendment Proposal, available:
http://www.ieso.ca/Documents/Amend/mr2015/MR_00414_R00_Amendment_Proposal_Ramp_Down_CMSC_v5.0.pdf , page 1

than the MCP when there is export congestion and lower than the MCP when there is import congestion. This produces a situation in which either side of the same transaction is settled at different prices: the intertie transaction is settled at the IZP, while the corresponding domestic transaction is settled at the MCP.[54] The difference in the money collected from the buyer and paid to the seller is referred to as congestion rent.

Intertie congestion can be difficult to predict and can significantly impact the profitability of an intertie transaction; congestion introduces financial risk to intertie traders. Accordingly, the IESO auctions off Transmission Rights (TRs), which provide a financial hedge against congestion by paying out the difference between the IZP and the MCP when the intertie is congested.

TR payments are based on the level of intertie congestion in pre-dispatch, whereas congestion rent is based on the amount of energy dispatched an hour later in real-time. Intertie traders contribute to congestion, and thus TR payments, when they are scheduled in pre-dispatch.

After pre-dispatch but before real-time, an intertie trader may fail a scheduled transaction for reasons within its control, in which case the transaction does not flow and no congestion rent is collected. The result is TR payments (based on conditions anticipated in pre-dispatch) in excess of congestion rents collected (based on real-time conditions). TR payments in excess of congestion rent collected are referred to as a "congestion rent shortfall"; the shortfall is funded by diverting auction revenues from transmission customers to TR owners. As discussed in Chapter 4, this transfer of funds from transmission customers to TR owners is inappropriate and ultimately to the detriment of Ontario consumers.

The IESO may levy an intertie failure charge on intertie traders that fail transactions for reasons within their control. The amount of the failure charge, if any, is calculated pursuant to a pre-set formula and that only take into account the impact of the failure on the MCP.[55] The failure

[54] For instance, an exporter pays the IZP, while the Ontario generator that supplies that export is paid the MCP. In the case of export congestion, the exporter pays the higher IZP and the Ontario generator is paid the lower MCP: the difference in payments accrues as congestion rent. For more information on congestion rent, see section 3.1.1 of Chapter 4.

[55] The intertie failure charge is calculated on the basis of the spread between the pre-dispatch and real-time Ontario MCP multiplied by the number of failed megawatts.

charge does not capture the impact of the congestion rent shortfall that the failure creates.[56] Consequently, when there is congestion on the intertie, the failure charge is incommensurate with the congestion rent shortfall the failure created, leaving Ontario consumers to pay for the shortfall.[57]

From January 2010 to April 2016, the Panel estimates that intertie failures within the control of market participants have resulted in congestion rent shortfalls of approximately $11 million. To highlight this behaviour, the Panel examines an exporter's activity at the New York intertie on February 20, 2016.

Analysis

On February 20, 2016, an intertie trader bid to export 400 MW from Ontario to New York in every hour of the day, with an average weighted hourly bid price of $33.98/MWh. Pre-dispatch prices were below $5/MWh in all hours of the day, so the intertie trader's exports were continually economic, resulting in a total daily pre-dispatch export schedule of 9,600 MWh. However, following pre-dispatch but before real-time, the intertie trader failed a total of 7,456 MWh (78%) of its exports from Ontario to New York. These export failures were within the intertie trader's control, resulting from the participant's failure to economically schedule the corresponding import transactions in the New York electricity market. The intertie trader was subject to export failure charges totalling $466.

In 10 of the 22 hours when the intertie trader failed an export transaction, the New York intertie was export congested, with an average intertie congestion price of $3.51/MWh. By failing its export transactions throughout the day, the intertie trader contributed to higher congestion prices and greater TR payments, but avoided paying congestion rents, leaving Ontario consumers to pay for the shortfall.

In this particular instance, the intertie trader who failed the exports also owned 400 MW of New York export TRs, meaning it was the beneficiary of the congestion it helped create. All told, the

[56] Export failure on the intertie could result in other impacts unaccounted for by the failure charge, such as the need to constrain off domestic generation. In particular, export failures can exacerbate surplus baseload generation conditions and could potentially lead to costly nuclear maneuvers.

[57] Not accounting for congestion rent shortfall in the failure charge may incent traders that own TRs to create congestion in order to receive TR payments, only to intentionally fail its transactions and avoid paying congestion rents.

intertie trader paid $1,537 in congestion rent, but collected $14,044 in TR payments, for a total profit to the intertie trader (and congestion rent shortfall to the Ontario consumer) of $12,507.

Table 3-3: Intertie Trader's Activities during Hours with Intertie Congestion February 20, 2016

Export Congestion Hour	Exports Scheduled in Pre-Dispatch (MW)	Exports Flowed in Real-Time (MW)	Congestion Rents Paid ($)	TR Payments Received ($)	Benefit to Intertie Trader (Congestion Rent Shortfall) ($)
1	400	57	163	1,144	981
2	400	164	800	1,952	1,152
4	400	0	0	1,200	1,200
6	400	38	114	1,200	1,086
10	400	0	0	104	104
11	400	0	0	3,000	3,000
15	400	0	0	404	404
17	400	0	0	1,600	1,600
22	400	200	460	920	460
23	400	0	0	2,520	2,520
Total	**4,000**	**459**	**1,537**	**14,044**	**12,507**

From January 2010 to April 2016, Ontario consumers have paid for approximately $11 million in congestion rent shortfall induced by intertie failures within the participant's control. This outcome is clearly inappropriate.

The Panel recognizes that the IESO has the authority within the Market Rules to adjust settlement amounts attributable to intertie failures within the market participant's control. While the Panel encourages the IESO to pursue any appropriate actions available to it via the Market Rules, it suggests that the IESO should also pursue a more fundamental solution that prevents situations like the one described above from occurring in the first instance. The Panel believes an appropriate failure charge should include congestion rents avoided.[58]

[58] In 2005, the IESO's Intertie Transaction Failure Working Group considered such an approach to calculating the intertie failure charge, but ultimately recommended the current methodology. In consideration of publicly available materials on the views and concerns of the working group and stakeholders at that time, the Panel found no compelling reason not to include the congestion rents avoided.

<u>Recommendation 3-2:</u>

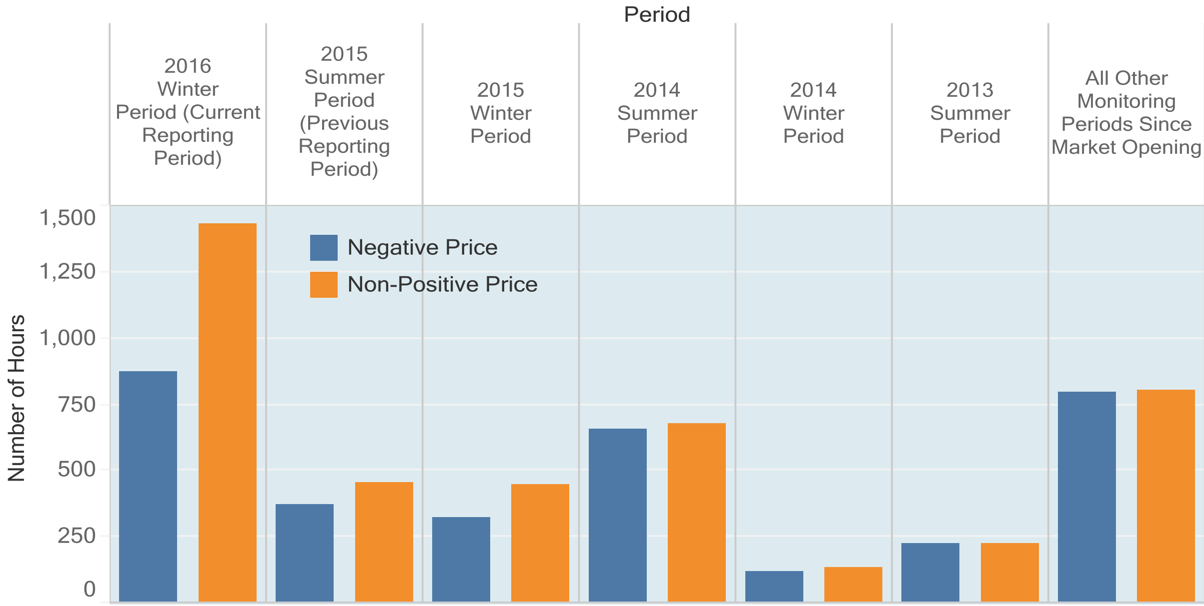
The IESO should revise the methodology used to set the intertie failure charge to include the congestion rents that an intertie trader avoids when it fails a scheduled transaction for reasons within its control.

2.4 *Examination of Non-Positive Price Hours*

The Panel has traditionally monitored low price hours when the HOEP is negative as a means to identify and report on potentially anomalous market outcomes. In recent reporting periods, there has been a significant increase in the frequency of zero-price HOEPs; the Panel has therefore altered its monitoring threshold to be non-positive HOEPs. Non-positive price hours typically signal an abundance of supply relative to demand, with contributing factors that include: low Ontario demand, failed export transactions, and an abundance of supply offered at non-positive prices.

During the Current Reporting Period there were 1,427 non-positive HOEPs, a significant increase from the corresponding period in the previous year when there were 447. As illustrated in Figure 3-4, the Current Reporting Period had the highest occurrence of non-positive HOEPs of all reporting periods since market opening; approximately 33% of all HOEPS during the Current Reporting Period were non-positive.

Figure 3-4: Non-Positive HOEPs by Reporting Period (Number of Hours)

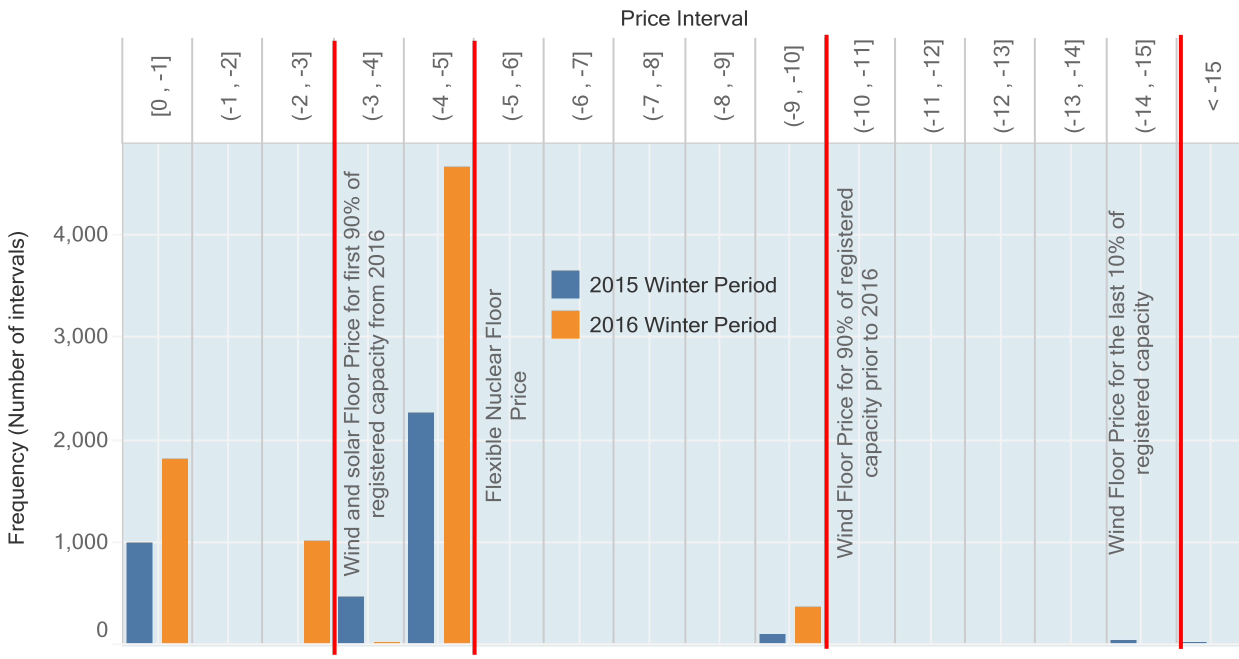


Non-positive HOEPs are prominent during periods of relatively low market demand, such as the early morning prior to 8:00 am or the late evenings after 10:00 pm. While non-positive HOEPs are particularly prevalent during weekends, they are becoming increasingly prominent during weekdays as well.

Figure 3-5 illustrates the frequency distribution for non-positive MCP's during the Current Reporting Period and the 2015 Winter Period, across $1/MWh price increments. The red vertical lines indicate the offer price floors imposed by the Market Rules for various resource types[59]. The price intervals demarcated by the offer price floors present the frequency with which certain resources go unscheduled in the unconstrained sequence. For example, any intervals to the right of the Flexible Nuclear Floor Price line indicate how often (375 intervals in the 2016 Winter Period) flexible nuclear went unscheduled in the Current Reporting Period.

[59] For more information on the offer price floors, see Market Manual 4 Part 4.2: Submission of Dispatch Data in the Real-Time Energy and OR Markets, available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/67f665f95aa94954b4a1d4504c772460.ashx

Figure 3-5: Frequency Distribution of Non-Positive MCPs November 2015 – April 2015 & November 2015 – April 2016 (Number of Intervals)[60]



The unprecedented frequency of non-positive prices reflects consistent surplus baseload generation. This is in line with expectations given relatively stable demand and the changes in Ontario's underlying supply mix. On September 27, 2016, the Minister of Energy directed the suspension of the IESO's second round of the Large Renewable Procurement (LRP II) process, citing Ontario's strong supply situation. LRP II had targeted the procurement of up to 600 MW of wind and 250 MW of solar, among other renewable resources. Reducing the amount of future grid-connected baseload capacity should help mitigate additional downward pressure on market prices. However, the Panel notes that according to the Ontario Planning Outlook (OPO), there is an additional 1,050 MW of wind and solar to be installed by 2017 (1,500 MW by 2020).[61] The Panel expects the addition of these low marginal cost resources will further suppress market prices.

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[60] On the horizontal axis of Figure 2-5, a square bracket indicates the number beside it is included in the MCP range while a round bracket indicates the number beside it is excluded.
[61] For more information on the Ontario supply outlook, see Module 4 of the Ontario Planning Outlook, available at: http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/ontario-planning-outlook/module-4-supply-outlook-20160901-pdf.pdf?la=en

Chapter 4: Matters to Report in the Ontario Electricity Marketplace

1 Introduction

In this chapter, the Panel presents its analysis of two aspects of the IESO-administered markets. The Panel's analysis considers the results and implications of the IESO's Demand Response Auction and examines disbursements made from the IESO's Transmission Rights (TR) Clearing Account.

2 Panel Investigations

The Panel may conduct an investigation into the conduct of market participants, including in relation to inappropriate or anomalous market conduct, when it considers such an investigation is warranted. The Panel currently has one gaming investigation under way in relation to a generator.

3 New Matters

3.1 Improving the Allocation of Disbursements from the Transmission Rights Clearing Account

Exporters have disproportionately benefited from disbursements from the TR Clearing Account, to the detriment of Ontario transmission customers. This disproportionate benefit is the result of the allocation methodology currently used to disburse funds from the account, and has resulted in $51 million being paid to exporters that the Panel believes ought to have been paid to Ontario transmission customers. Given the ongoing and material nature of the issue, future transfers will be significant if the current disbursement allocation methodology continues.

In support of an alternate disbursement allocation methodology, the sections that follow provide an overview of Ontario's intertie pricing system, the TR market and the IESO's administration of the TR Clearing Account. The sections conclude with a recommendation to the IESO to revise the disbursement methodology to what the Panel considers to be a fairer allocation.

3.1.1 Overview of the Transmission Rights Market and Clearing Account

Intertie Congestion and Congestion Pricing

Ontario's wholesale electricity market employs a uniform price design in which Ontario consumers and producers buy and sell electricity at the same price province-wide: this price is known as the Market Clearing Price (MCP). The uniform price design does not apply to the interties that connect Ontario to its neighbouring jurisdictions; exporters and importers pay, or are paid, the relevant Intertie Zonal Price (IZP). The IZP differs from the MCP when there is congestion on the intertie. When there is no congestion the IZP is equal to the MCP.

Transmission lines can only accommodate a certain amount of electricity flow at a given time; this limit is referred to as the scheduling limit. Congestion occurs when the quantity of electricity scheduled to flow over the transmission line exceeds the scheduling limit.

When intertie traders collectively offer to buy or sell a net quantity[62] of economic imports or exports that exceeds the scheduling limit of the intertie, the intertie becomes congested. Under such circumstances there are more economic transactions on offer than there is transmission capacity, and the IESO must determine which transactions are scheduled and which are not: this is done through economic selection.

The IESO's dispatch algorithm schedules transactions based on their economic merit: from low-cost to high-cost for importers, and from high-price to low-price for exporters.[63] Transactions are scheduled in this manner until the intertie's scheduling limit is reached, or until there are no further economic transactions. In doing so the algorithm looks to maximize the gains from trade.

If intertie traders, on a net basis, offer to sell imported electricity to Ontario at a cost below the MCP and in excess of the intertie's scheduling limit, the intertie becomes import congested. Under such circumstances there is an oversupply of electricity at the intertie: this abundance is reflected in an IZP that is less than the MCP.

Import Congestion = Intertie Zonal Price < Market Clearing Price

If intertie traders, on a net basis, bid to buy and export electricity from Ontario at a price above the MCP and in excess of the intertie's scheduling limit, the intertie becomes export congested. Under such circumstances there is excess demand for electricity at the intertie: this scarcity is reflected in an IZP that is greater than the MCP.

Export Congestion = Intertie Zonal Price > Market Clearing Price

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[62] Interties are scheduled on a net basis, meaning gross import transactions can exceed the scheduling limit if there are offsetting exports scheduled in the opposite direction, and vice versa. Net imports (or net exports) cannot exceed the scheduling limit.

[63] For example, an importer willing to sell electricity to Ontario at $20/MWh is scheduled ahead of an importer willing to sell at $30/MWh. Conversely, an exporter willing to buy electricity from Ontario at $50/MWh is scheduled ahead of an exporter willing to pay $40/MWh.

Congestion Rents

Importers are paid the IZP and exporters pay the IZP, which as discussed above, is higher or lower than the MCP when there is intertie congestion. This produces a situation in which either side of the same transaction is settled at different prices: the intertie transaction is settled at the IZP, while the corresponding domestic transaction is settled at the MCP. For instance, an exporter from Ontario pays the IZP, while the Ontario generator that supplies that export is paid the MCP. Likewise, an import into Ontario is paid the IZP, while the corresponding Ontario consumer pays the MCP. The difference in the money collected from the buyer and paid to the seller is referred to as congestion rent. Total congestion rent at a given intertie for a given hour is equal to the difference in prices multiplied by the net electricity flow in that direction.

$$\text{Import Congestion Rent} = (\text{MCP} - \text{IZP}) * \text{Net Import Schedule}$$

$$\text{Export Congestion Rent} = (\text{IZP} - \text{MCP}) * \text{Net Export Schedule}$$

Congestion rent reflects the value of scarce transmission capacity. The more valuable access to a transmission path is to those who wish to utilize it, the higher the congestion rent collected. Given intertie traders are willing to pay for scarce transmission capacity in the form of congestion rent, it follows that the owner of transmission capacity would benefit from making that transmission capacity available.

There are five companies which own and operate transmission lines in Ontario. Each of those five companies is subject to rate regulation by the Ontario Energy Board (OEB) which approves the rates they charge to their transmission customers. The regulated rates are derived from the revenue requirements of the companies, which is the revenue level at which they recover their costs including a return on equity.[64] Any congestion rent collected by the IESO and paid to transmission owners would go to offset the revenue requirement of those companies, thus reducing the regulated rates charged to their transmission customers. It follows that, in Ontario, transmission customers benefit from congestion rent.

[64] For a brief overview of the OEB's role in energy sector regulation and rate setting, see its Backgrounder on Energy Sector Regulation, at available at: http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/Energy_Sector_Regulation-Overview.pdf

Transmission Rights

As explained above, the price intertie traders are settled at (the IZP) differs from the uniform Ontario price (the MCP) when there is intertie congestion. Intertie congestion can be difficult to predict and can significantly impact the profitability of an intertie transaction; congestion introduces financial risk to intertie traders. In order to provide the opportunity to hedge against that risk, the IESO operates a TR market.

TRs provide a financial hedge against price differences between the IZP and the MCP. The IESO offers an array of different TRs at monthly and quarterly auctions. The IESO auctions TRs by the megawatt, with each TR being specific to an intertie, a trade direction (import or export) and a length of time (1-month or 1-year). For example, a prospective exporter looking to hedge against congestion risk may purchase a TR for the New York intertie, in the export direction, that is valid for April 2017.

The owner of a one megawatt TR is entitled to a payment equal to the difference between the IZP and MCP every time there is congestion on the relevant intertie, in the relevant direction, and during the relevant time period:

> When import congested, the Import TR Payment = (MCP – IZP) * Import TRs owned
> When export congested, the Export TR Payment = (IZP – MCP) * Export TRs owned

Extending the New York export TR example from above, the owner of 100 MWs of the aforementioned TRs would receive a TR payment of $1,500 under the following conditions:

> MCP = $30/MWh
> IZP = $45/MWh
> Export TRs Owned = 100 MW
> TR Payment = (IZP – MCP) * Export TRs Owned
> TR Payment = ($45 – $30) * 100
> TR Payment = $1,500

The exporter, who pays $4,500 to purchase 100 MW at the $45/MWh IZP, receives a $1,500 TR payment. The TR payment makes the net cost of the export $3,000; equivalent to having purchased 100 MW at the $30/MWh MCP. Effectively, an intertie trader that hedges their transaction with TRs ensures that they can purchase power at the MCP, as opposed to the IZP, regardless of whether or not there is congestion.

TR payments are designed as a full hedge against congestion rents; accordingly, TR payments and congestion rents collected should be approximately equal. By purchasing a TR, the owner has essentially purchased the right to the congestion rents on that intertie.

Transmission Rights Auction Revenues

By selling TRs the IESO transfers the benefit of congestion rents from transmission customers to the purchasers of TRs. In return for relinquishing that benefit, transmission customers receive the proceeds generated from the sale of TRs; these proceeds are known as "auction revenues". If transmission customers did not receive TR auction revenues then, in the Panel's view, they would be made worse off by the IESO's sale of TRs.

Transmission Rights Clearing Account

The IESO administers Ontario's TR market and manages the flows of money through the TR Clearing Account. There are five flows of money into or out of the account, three credits and two debits:

Credits

- Congestion Rents
- Auction Revenues
- Interest accrued on funds in the account

Debits

- TR Payments
- Disbursements

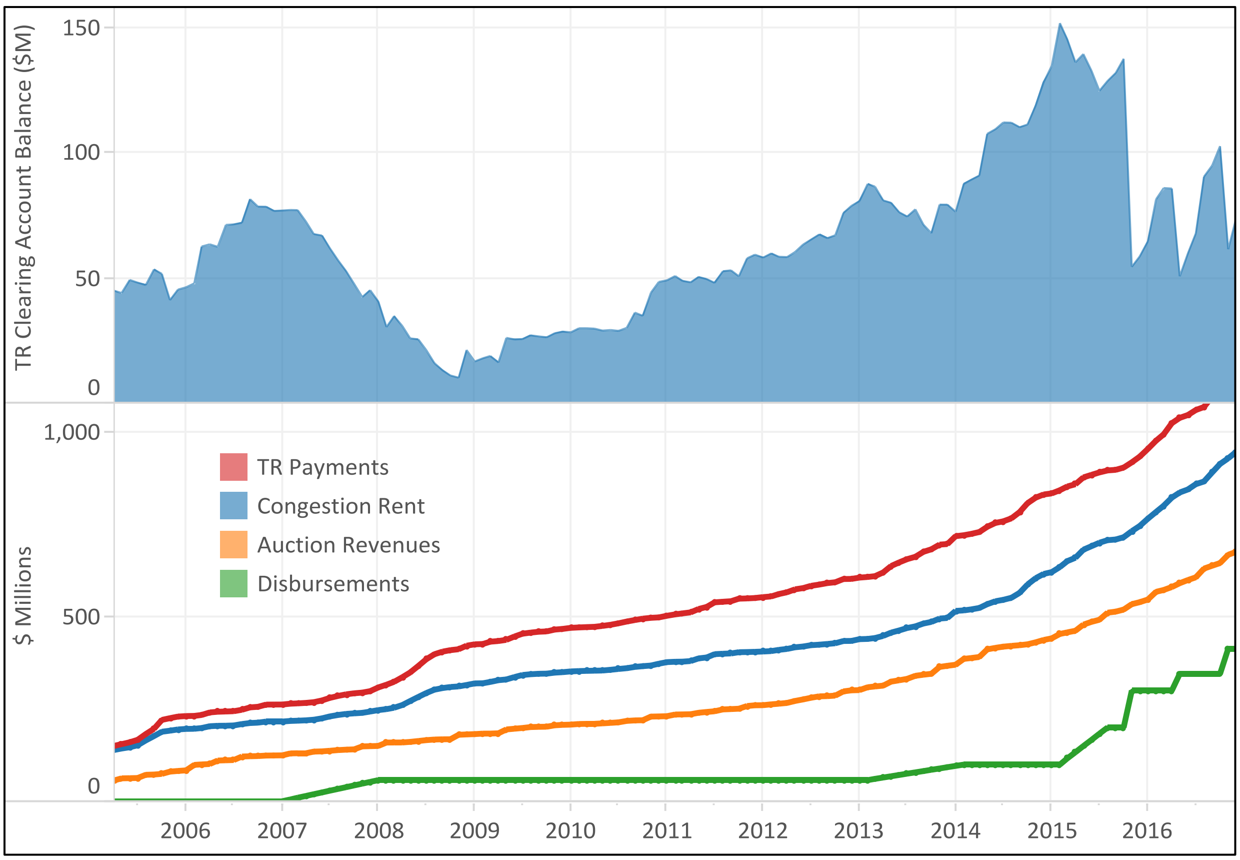
As discussed in the Transmission Rights section above, congestion rents and TR payments should be approximately equal, and thus offset one another in terms of the balance of the TR Clearing Account. The account's remaining credits, auction revenues and any accrued interest, are remitted to transmission customers through the disbursement debit transaction. It follows that, over time one would expect:

1) TR payments and congestion rents would be approximately equal, and

2) Auction revenues (plus interest) and disbursements would be approximately equal.

Figure 4-1 below shows the cumulative total of each of the TR Clearing Account's line items (excluding interest) since market opening, as well as the balance of the TR Clearing Account over time.

Figure 4-1: Transmission Rights Clearing Account Balance
May 2005 – December 2016
($ millions)



At the end of 2016, the TR Clearing Account had a balance of $74 million. For reasons discussed in the following section, neither of the aforementioned equalities materialized over time: TR payments have exceeded congestion rents, and auction revenues have exceeded disbursements, both by significant margins.[65]

Disbursements from the Transmission Rights Clearing Account

The IESO Board of Directors (the "IESO Board") authorizes disbursements from the TR Clearing Account.[66] From market opening in May 2002, to the beginning of 2013, the IESO authorized one disbursement totalling $57 million; yet, had collected $302 million in auction revenues. Of the $245 million in undisbursed auction revenues, $85 million was in the TR Clearing Account at that time. The remaining $160 million had been paid to TR owners in order to fund TR payments in excess of congestion rents (see Figure 3-1). These excess TR payments represent money that could have been disbursed to transmission customers, but that was instead diverted to TR owners.

This considerable transfer from transmission customers to TR owners was primarily the result of an IESO Board decision in 2003. The decision permitted the IESO to intentionally over-sell TRs so that TR payments would exceed congestion rents collected, thus depleting the TR Clearing Account of auction revenues and paying them to TR owners.[67] In doing so, the IESO believed it was providing liquidity to the TR market and encouraging trade.

In its January 2013 Monitoring Report, the Panel examined the impacts of the IESO Board's decision and recommended a policy change. The Panel's proposed change would balance TR payments and congestion rents collected; stopping the transfer of funds to TR owners and allowing for all auction revenues to be disbursed to transmission customers.[68] The IESO adopted the Panel's recommendation and changed its policy; it is now in the process of implementing those changes.

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[65] Further to the aforementioned equalities, one would expect that each of TR payments, congestion rents, auction revenues and disbursements would be approximately equal over time. Prospective TR owners should be willing to pay (in the form of auction revenues) the expected value of congestion rents for TRs; TR payments are intended to be a full hedge against congestion rents and should thus be equal to congestion rents; all auction revenues would be disbursed to transmission customers.

[66] See Chapter 8, Section 4.18.2 of the IESO's Market Rules, available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/586603f319a04df9a08fcea9f8705b32.ashx

[67] For more information see the IESO's MR-00242 Market Rule Amendment Proposal, available at: http://www.theimo.com/Documents/Amend/mr/mr_00242_Q00.pdf

[68] For more information see pages 146-161 of the Panel's January 2013 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf

In addition to the aforementioned policy change, the Panel recommended that the IESO disburse the funds in the TR Clearing Account at that time, as well as formalize a process for disbursing funds once annually.[69] In response to these recommendations the IESO disbursed $42 million to transmission customers in 2013, and formalized a process to review the balance in the account on a semi-annual basis to determine whether a disbursement should be made.[70] Since the Panel's 2013 recommendations, the IESO has disbursed $355 million from the TR Clearing Account to transmission customers.

3.1.2 Allocating Disbursements to Transmission Customers

Through a series of rules and definitions, the Market Rules dictate the methodology for disbursing funds from the TR Clearing Account.

> *Subject to section 4.18.3 [which establishes the TR Clearing Account reserve threshold], the IESO Board may, at such times as it determines appropriate, authorize the debit of funds from the TR clearing account for the <u>purpose of using those funds to offset the transmission services charges</u> referred to in section 3.6.3 of Chapter 9 [which references the disbursement formula].*[71] (emphasis added)

All consumers, both domestic and exporters, pay some form of transmission service charge, thus entitling them to disbursements under the Panel's reading of the above Market Rule.[72] While the rule establishes to whom and why disbursements are to be paid, it does not establish how much each transmission customer ought to receive.

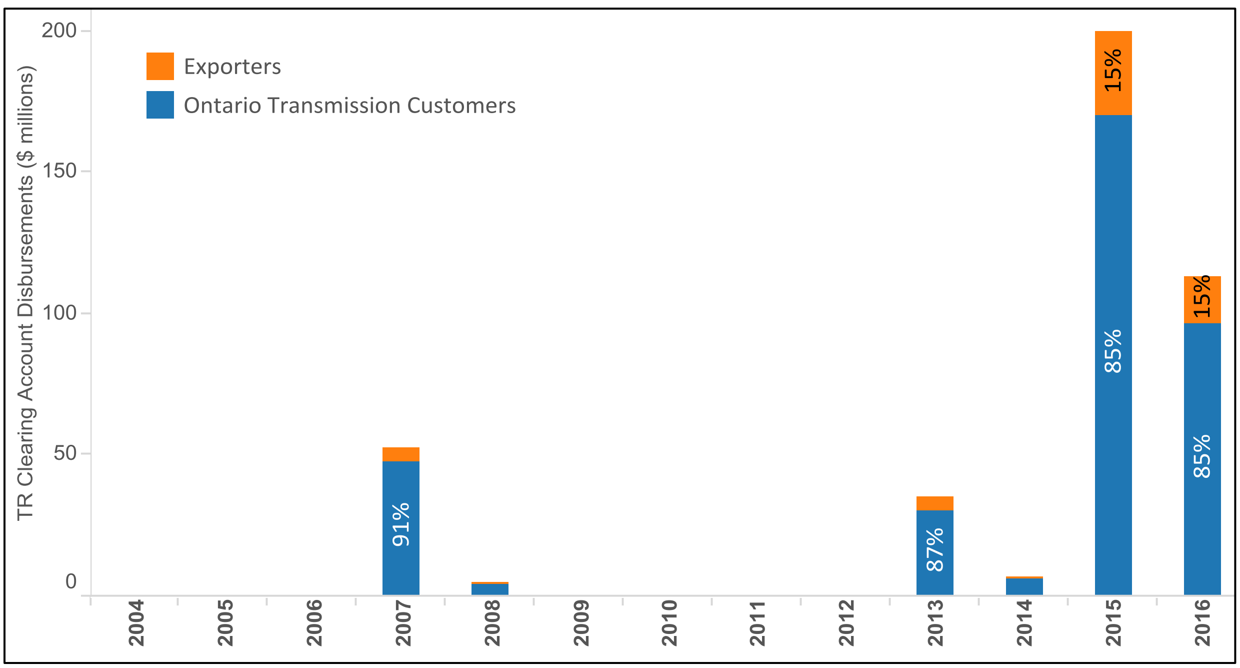
The formula for determining each transmission customer's share of disbursements from the TR Clearing Account is found in Chapter 9, Section 4.7 of the Market Rules. This formula dictates

[69] *Ibid.*
[70] For more information see the IESO's MR-00421 Market Rule Amendment Proposal, available at: http://www.ieso.ca/Documents/Amend/mr2015/MR_00421_TRCA_Amendment_Proposal%20v5_0.pdf
[71] See Chapter 8, Section 4.18.2 of the IESO's Market Rules, available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/586603f319a04df9a08fcea9f8705b32.ashx
[72] See the definition for "Transmission Service Charges" and "Transmission Services" in Chapter 10 of the IESO's Market Rules, available at: available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/4278d372760e4e719f78019aa2953c6e.ashx

that disbursements are proportionally allocated to consumers based on their share of total demand over the previous six months.[73]

Since market opening, the IESO Board has approved, and the IESO has made, six disbursements from the TR Clearing Account, totalling $412 million. These disbursements were allocated amongst Ontario transmission customers and exporters based on their proportion of demand over the month prior to disbursement, or six months in the case of the three most recent disbursements. Figure 4-2 displays disbursements to Ontario transmission customers and exporters by year from 2004 to 2016.

Figure 4-2: Disbursements from the TR Clearing Account 2004 – 2016 ($ millions)



From 2004 to 2016, Ontario transmission customers received $354 million in disbursements from the TR Clearing Account (86% of total disbursements), while exporters received $58 million (14%).

[73] See Chapter 9, Section 4.7 of the IESO's Market Rules, available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/bfddf5699fdd4cce9fde8822336e747b.ashx.Earlier disbursements were allocated based on shares of total demand during the month prior to disbursement.

The decision to allocate disbursements based on shares of demand appears to date back to a Technical Panel decision in July of 2000. At that time, the Technical Panel was presented with a number of options for disbursing funds from the TR Clearing Account, including: disbursing funds to Ontario consumers only, exporters only, or both based on shares of demand. The Technical Panel ultimately endorsed disbursing funds based on shares of demand; this methodology was adopted for market opening and continues today. Unfortunately, the Technical Panel's rationale for selecting this option is not well-documented.

When the Panel assesses elements of market design, market rules or procedures, it considers the impacts of different options across various measures and principles. As dictated by its mandate, the Panel's primary considerations involve the impact on the efficient and fair operation of competitive markets.[74] While the Panel is not mandated to monitor or report on the reliability of the grid, it also considers potential reliability impacts when making its assessments.

In the Panel's assessment, there are no efficiency or reliability impacts associated with choosing one reasonable allocation methodology over another. In order for such impacts to occur, the real-time consumption decisions of market participants must be meaningfully influenced by disbursement considerations. For instance, under the current design an exporter could conceivably increase its trade activity in order to increase its share of disbursements. That said, any meaningful link between real-time consumption decisions and disbursement considerations is unlikely. Not only are future disbursements distant and unknown, but any additional disbursement revenue associated with increasing demand would most likely be far outweighed by the additional costs of the increased consumption. In other words, real-time incentives remain the driver of real-time behaviour, not disbursements.

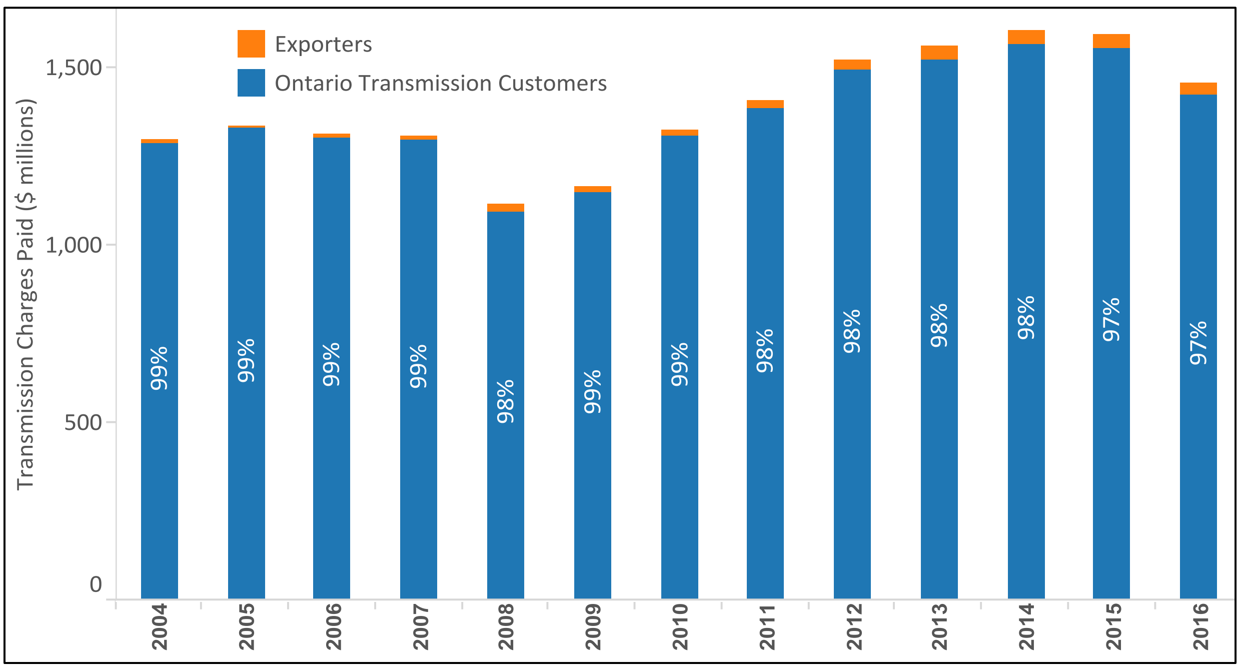
With no impact on efficiency or reliability, the Panel looked to its other mandated principle, namely fairness, to assess disbursement options. As stated in Chapter 8, Section 4.18.2 of the Market Rules, the purpose of disbursements from the TR Clearing Account is to offset transmission service charges; the disbursement is a rebate on costs paid. Accordingly, the Panel believes that a fair allocation would have each customer receive a rebate proportionate to its

[74] See the Ontario Energy Board's Bylaw #3, available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/About%20the%20OEB/OEB_bylaw_3.pdf

share of costs paid. For instance, a transmission customer that paid 1% of the total transmission service charges over the accrual period would receive 1% of the disbursements at the end of that period. Unfortunately, the current allocation methodology has not resulted in what the Panel considers to be a fair allocation of disbursements.

Figure 4-3 displays the transmission service charges paid by Ontario transmission customers and exporters by year from 2004 to 2016.

Figure 4-3: Transmission Charges Paid
2004 – 2016
($ millions)



From 2004 to 2016, Ontario transmission customers paid $17.7 billion in transmission charges (98.3% of total charges), while exporters paid $304 million (1.7%). Despite paying 98.3% of total transmission charges, Ontario transmission customers received only 86% of disbursements from the TR Clearing Account (see Figure 3-3); exporters received 14% of disbursements despite paying only 1.7% of total transmission charges.

The misalignment stems from the fact that disbursements are allocated based on shares of demand, not shares of transmission service charges paid. The transmission charge associated with a megawatt-hour of Ontario demand is significantly higher than the transmission charge associated with a megawatt-hour of export demand. As a result, exporters benefit disproportionately when disbursements are based on demand; such a methodology does not result in what the Panel considers to be a fair allocation.[75]

Had disbursements been allocated in line with the Panel's view on fairness, Ontario transmission customers would have received disbursements totalling $405 million while exporters would have received $7 million. Under such an allocation, Ontario transmission customers would have received an additional $51 million in disbursements that was actually paid to exporters.

Given the IESO's revised TR Clearing Account policies aimed at balancing congestion rents and TR payments, the Panel expects all future auction revenues to be disbursed to transmission customers. Since 2010, auction revenues have increased each year, eclipsing $100 million per year in 2015 and 2016. Left unremedied, the disbursement allocation methodology will continue to be a significant issue going forward.

Recommendation 4-1:

A. ***The IESO should revise the manner in which it allocates disbursements from the Transmission Rights Clearing Account such that disbursements are proportionate to transmission service charges paid over the relevant accrual period.***
B. ***The IESO should not disburse any further funds from the Transmission Rights Clearing Account until such time that Recommendation 4-1(A) has been addressed.***

3.2 *Assessment of the IESO's Demand Response Auction*

Since 2004, the Government of Ontario has been mandating the development of electricity conservation programs. The primary aim of these programs is to alleviate the need to build new generation facilities by reducing demand during peak periods.[76] Demand Response (DR) programs, which incent consumers to reduce consumption during periods of high prices, high demand or tight supply, have been a large part of that conservation effort.

[75] The transmission charges applicable to Ontario transmission customers are broken down into three separate OEB approved rates: Network Service Charge, Line Connection Service Charge and Transformation Connection Service Charge. Together these rates currently total $8.97/MWh. Exporters are subject to the Export Transmission Service (ETS) charge, which is currently set at $1.85/MWh. Both the rates charged to Ontario transmission customers and exporters are set annually and have varied over time, though the rates applicable to Ontario transmission customers have always been higher than the ETS charge.

[76] The Ministry of Energy's *Conservation First: A Renewed Vision for Energy Conservation in Ontario* report states that, "Ontario's vision is to invest in conservation first, before new generation, where cost-effective." The report is available at: http://www.energy.gov.on.ca/en/files/2013/07/conservation-first-en.pdf

The IESO is responsible for achieving the conservation related policy goals set forth by the Ministry of Energy. Prior to 2015, bilateral contracting was the primary means of procuring the necessary DR resources to meet policy objectives; in 2015, the IESO developed the DR auction. The DR auction introduced a competitive, flexible and transparent process for procuring DR resources, where formerly there was none.

The DR auction occurs once annually and procures DR resources for a period of one year. As part of the auction process eligible resources submit the quantity of DR capacity they are willing to provide, and the price at which they are willing to provide it; the IESO uses those offers to build a supply curve. The DR auction clearing price is set where the supply curve intersects the administratively determined demand curve; all resources selected in the DR auction receive the clearing price.[77] To be paid, resources procured through the DR auction must be made available to reduce consumption during specified periods, and must actually reduce consumption when certain activation criteria are met. For this service, resources procured in the 2016 and 2017 DR auctions will be paid up to a total of $73 million; these payments are recovered from Ontario consumers through an uplift charge.[78]

Two types of resources are permitted to participate in the DR auction: dispatchable loads and hourly demand response (HDR) resources. Dispatchable loads already participate in the energy market, changing their consumption in response to five-minute price signals; participating in the DR auction should not materially change the behaviour of these resources. For that reason, the following sections focus on HDR resources, unless otherwise stated. HDR resources are not willing or able to respond to five-minute price signals, and would not participate in the energy market absent some incentive, such as the payments received through the DR auction. To date, approximately 72% of all DR procured through the DR auction has been from HDR resources.

[77] Given the differences in supply and demand in different areas of the province, the IESO limits the amount of DR procured in each zone. If the limit is reached in a given zone, the clearing price in that zone may differ from the others.

[78] While auction payments are technically recovered from Ontario consumers via uplift, the uplift is allocated in the exact same manner as the Global Adjustment. In other words, a consumer's share of this uplift is based on whether they are Class A or Class B customers: Class A customers are charged based on their share of consumption during the five coincident peak demand hours during a year, Class B customers based on their volumetric consumption on all days. Exporters do not pay this uplift.

The IESO has stated that the DR auction is part of a suite of programs and incentives that will help meet the Ministry of Energy's conservation related policy goals.[79] However, for the reasons explained in this section, it is unlikely that the current DR program will actually contribute to conservation or demand reduction. Briefly, this is because the rules associated with the DR auction establish thresholds for activation which have not been realized to date and are unlikely to be realized in the future.

3.2.1 Meeting the Ministry of Energy's Policy Goal

Having said that, it is worth noting that the IESO views the DR auction as an initial step towards the evolution of capacity procurement in the province; one in which all generating and DR capacity is procured through an integrated auction.[80] The Panel supports this longer-term objective.

In 2013, the Ministry of Energy issued its most recent conservation related policy goal: use DR to meet 10% of peak demand by 2025 (approximately 2,400 MW under then forecasted conditions).[81] The IESO views the DR auction as a means of achieving the Ministry's policy goal:

> *Creating a DR auction will support the province's objective for DR to meet 10 per cent of Ontario's peak demand by 2025 and encourage new competitive DR resources to help meet that goal for Ontario's electricity system.*[82] – IESO

In order for the IESO's suite of DR programs and incentives to achieve peak demand reductions, DR not only needs to be available during periods of peak demand, but must also be activated during those periods. As such, it is important to understand the difference between the procurement of DR capacity (i.e. DR availability), and achieving peak demand reductions (i.e.

[79] See the IESO's *Demand Response Stakeholder Engagement Plan,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/dra/20140911-dr-auction_se-plan_draft.pdf?la=en
[80] For more information on the IESO's capacity auction development plans see slides 7 and 8 of its *Developing a Market Renewal Workplan* presentation, available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/me/me-20160419-developing-a-workplan.pdf?la=en
[81] For more information on the Ministry of Energy's policy goal see pages 20-27 of the *2013 Long Term Energy Plan* report, available at: http://www.energy.gov.on.ca/en/files/2014/10/LTEP_2013_English_WEB.pdf
[82] See the IESO's *Demand Response Stakeholder Engagement Plan,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/dra/20140911-dr-auction_se-plan_draft.pdf?la=en

DR activations). A program that procures DR capacity, but does not result in DR activations during peak demand, will not help achieve the Ministry of Energy's policy goal.

As currently designed, DR procured through the IESO's DR auction is unlikely to be activated during periods of peak demand. To understand why that is, it is necessary to understand both the availability obligation placed on DR resources and the criteria under which they are activated.

Availability Obligation

DR resources procured through the DR auction are required to participate in the energy market for certain pre-determined commitment periods and availability windows. The availability window applies to business days only: 12 PM to 9 PM from May to October (Summer Commitment Period) and 4 PM to 9 PM from November to April (Winter Commitment Period).

During the availability windows DR resources must enter bids into the energy market at prices between $100/MWh and $2,000/MWh. These bids represent the price at which the resource is willing to be activated for DR. The bids must be entered into the market before the IESO's day-ahead process starts, and remain in the market until the IESO determines the resource will not be activated, or until an activation is completed.

Activation Criteria

In order for a DR resource to be activated during the applicable availability window, it must receive both a standby notice and an activation notice from the IESO.

First, a DR resource will receive a standby notice at or before 7 AM if the pre-dispatch nodal price at its location is above its bid price for four consecutive hours within the availability window. Second, if the resource receives a standby notice, it may next receive an activation notice 2.5 hours prior to activation, so long as the price remains above its bid price for four consecutive hours within the availability window. If a DR resource receives an activation notice it must reduce its consumption for a period of four hours, beginning with the first hour included in the activation notice.

Consider the following example: a DR resource is procured for the Winter Commitment Period; to fulfill its availability obligation it bids $1,999/MWh into the energy market during all hours of the availability window. For simplicity, assume that any activation will start at 4 PM and conclude at 8 PM.[83]

Under these conditions the DR resource will receive a standby notice if, during any of the hours before 7 AM, the pre-dispatch nodal prices for the 4 PM to 8 PM activation period exceed the resource's $1,999/MWh bid. To then receive an activation notice, the same conditions must persist at 1:30 PM, in which case the resource must reduce its consumption for the 4 PM to 8 PM activation period.

Prospect of Being Activated

Given the activation criteria described above, the likelihood of an activation is remote. This is borne out by events since the Current Reporting Period; since the first commitment period started in May 2016, no HDR resource has been activated.

Under the program rules DR resources can bid into the energy market at any price between $100/MWh and $2,000/MWh; the higher the bid price, the lower the likelihood of being activated. Table 4-1 contains the prices used to date by HDR resources when submitting their bids to the energy market.

Table 4-1: HDR Resources' Bids into the Energy Market
May 2016 – December 2016

Observed Bid Prices	HDR Capacity Bid at Observed Price
$1,999/MWh	82%
$500/MWh	18%

Since the start of the first commitment period 82% of all DR capacity has been bid into the energy market at the program's maximum allowable price. While the Panel supports DR resources being able to bid into the energy market at any price, bidding at the maximum allowable price, in conjunction with the current activation criteria, means that HDR resources will not be activated. Indeed, the Panel's analysis indicates that any bid price over $220/MWh would not have been activated during the period.

[83] During the Winter Commitment Period, a DR resource may also have an activation period from 5 PM to 9 PM. During the Summer Commitment Period an activation period may span any four consecutive hours between noon and 9 PM.

Given Ontario's current surplus supply conditions and the prices that persisted over the period, it is not surprising that there were no activations.

That said the province has not always been flush with surplus supply. In 2005 and 2006 all-time demand records were being set in Ontario, and in the winter of 2014 the "polar vortex" weather event increased demand and constrained supply. To get a sense of the likelihood of an activation given the current activation criteria, the Panel applied the same criteria to all hours dating back to the high demand conditions experienced in 2005. Table 4-2 displays the number of HDR activations that would have occurred at various bid prices since 2005.

Table 4-2: Hypothetical HDR Activations by Bid Price
2005 – 2016
(Number of Activations)

Energy Bid Price ($/MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
100 - 200	552	152	199	188	1	26	18	16	4	168	66	88
200 - 300	65	16	7	4	-	3	4	-	5	51	-	33
300 - 400	27	9	-	4	-	-	-	-	-	6	-	-
400 - 500	27	9	-	-	-	-	-	-	-	-	-	-
500 - 600	25	3	-	-	-	-	-	-	-	-	-	-
600 - 700	15	1	-	-	-	-	-	-	-	-	-	-
700 - 800	8	1	-	-	-	-	-	-	-	-	-	-
800 - 900	4	-	-	-	-	-	-	-	-	-	-	-
900 - 1,000	1	-	-	-	-	-	-	-	-	-	-	-
1,000+	-	-	-	-	-	-	-	-	-	-	-	-

Since 2005, no bid price above $1,000/MWh would have been activated, yet most HDR resources bid at twice that price. Any bid price over $400/MWh would not have been activated since 2006.[84]

Even under the most aggressive of demand projections, peak demand is not expected to return to record 2005 and 2006 levels until 2029.[85] Ontario is also in a better supply situation than it was during those years, having added thousands of megawatts of capacity to the grid.[86]

[84] Going forward, new HDR resources may emerge at different locations on the grid; their likelihood of activation may differ.
[85] See the IESO's most recent *Ontario Planning Outlook*, available at: http://www.ieso.ca/Documents/OPO/Ontario-Planning-Outlook-September2016.pdf
[86] See *The Need for Capacity* section below for a summary of Ontario's current supply and demand conditions.

The Panel is mindful that reducing consumption during periods of peak demand is a means to an end, and should not be a goal unto itself. A DR resource may wish to consume during periods of high demand, but may be incented to abstain in order to alleviate the need to build additional supply. In this way, DR programs incur short-term costs (i.e. curtailing otherwise efficient energy consumption) in order to avoid long-term costs (i.e. reducing the need for additional peak generation capacity). As long as the avoided long-term costs exceed the incurred short-term costs, reducing peak demand can be efficient.

Ontario is currently flush with supply, and will continue to be for the foreseeable future (see *The Need for Capacity* section below). Even with considerable demand growth, there is little need to build new capacity. Consequently, consumption during peak periods results in no additional long-term capacity costs, meaning demand reductions during these periods are unnecessary and likely inefficient. It follows that payments to procure DR, such as those provided by the DR auction, are also unnecessary and inefficient.

3.2.2 Meeting the IESO's Capacity Objective

As mentioned in the previous section, the IESO's DR auction is unlikely to provide energy through DR activations given the current activation criteria.

The notion that the DR auction is procuring capacity only is consistent with the program's availability obligations, as well as the manner in which DR resources are compensated. Specifically, DR resources are paid to be available for activation, not to be activated; there are no minimum requirements on the number of times a resource must be activated. In furtherance of this idea, the IESO plans to integrate the DR auction and its participants into the broader capacity auction currently being developed through the IESO's Market Renewal initiative.[87] In the sections that follow, the Panel assesses the appropriateness of the DR auction as a means to procure capacity.

[87] For more information on the IESO's capacity auction development plans see slides 7 and 8 of its *Developing a Market Renewal Workplan* presentation, available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/me/me-20160419-developing-a-workplan.pdf?la=en

Availability Obligation and Activation Criteria

Unlike meeting the Ministry of Energy's policy goal of using DR to reduce peak demand, procuring capacity does not necessarily come with the expectation that it will be utilised regularly or predictably. The IESO must procure enough capacity to ensure that Ontario's electricity needs are met, plus some additional capacity to ensure reliability. On that basis, one would expect there to be a portion of capacity that is rarely if ever used. Specifically, capacity resources with high bids in the energy market, such as those procured to date through the DR auction, are the last to be activated and are likely only needed on rare occasions. For DR capacity to be of use, the activation criteria needs to result in consumption reductions on those infrequent occasions when those resources are needed.

As noted earlier, HDR resources bidding at the maximum allowable energy market price (82% of all HDR resources to date) would not have been activated from 2005 onwards; resources bid above $400/MWh would not have been activated since 2006. There have been occasions since 2005, including during the very tight supply conditions experienced during the winter of 2014, when DR activations could have been beneficial.[88] To that end, the Panel encourages the IESO to assess whether changes to the current availability obligations and activation criteria should be made in order to facilitate activations when needed.

Technology-Specific Procurement

In terms of satisfying the need for capacity, capacity from DR is no different than capacity from other resources, such as gas-fired generators. Given the substitutability of capacity from different technologies, the procurement process should be technology neutral, not favouring one technology over another. Technological neutrality allows the procurement mechanism to select the lowest cost capacity, no matter the resource type. In order for the procurement mechanism to be technologically neutral it must permit all resources to compete against one another to supply capacity, and place identical obligations on all resources procured. The need for technology-neutral procurement was recently supported by the Minister of Energy, Glenn Thibeault:

[88] The Panel finds it instructive that, over the same period, there were numerous other DR programs with differing activation criteria that resulted in activations, including activations under the program the DR auction is effectively replacing.

Upon taking this office, I was interested to learn that our previous procurements were essentially segmented into "technology-specific" allotments. In this day and age, with the level of innovation, pace of technological change – as well as the clear benefit to ratepayers from competitively procured resources; it is essential that we begin moving towards more "technology-agnostic" procurements.

Too often we have sought to impose strict requirements on the system operator. Rather, as we seek to undertake future procurements – we should be focused on outcomes, rather than contracting with specific technologies. Moving to become technology-agnostic will provide new opportunities for innovation and modernization. We must unleash the electricity sector and our system operator to find the appropriate mix to fulfil a capacity auction would ensure that ratepayers receive the best prices possible.[89]

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Allocating the precise mix of technology types has largely been arbitrary and led to suboptimal siting, uncompetitive prices and heightened community concerns.[90]

The DR policy goal set by the Ministry of Energy in 2013 is technology specific, as was the IESO's corresponding procurement. Currently, DR is the only capacity procured through an auction process. By limiting competitive procurement to one resource type, the IESO is limiting its ability to procure capacity at least cost. Fortunately, the IESO is considering the introduction of a technology-neutral capacity market, allowing for DR resources to compete against other technologies to provide capacity at least cost in the future.

The Need for Capacity

The quantity of DR capacity procured through the DR auction is determined by the intersection of the participant-offered supply curve and the IESO determined demand curve. The demand curve sets the bounds for how much DR capacity will be procured at different prices, including the maximum quantity at the auction's lowest price, and the minimum quantity at its highest price.

[89] Speech delivered by Glenn Thibeault (Minister of Energy) to the Empire Club of Canada on November 28, 2016.
[90] Comments made by Glenn Thibeault following his speech to the Economic Club of Canada on February 24, 2017, as reported in the Globe and Mail's article: *Ontario Liberals Eye Electricity Market Overhaul to Lower Rates*, available at: http://www.theglobeandmail.com/news/ontario-liberals-eye-electricity-market-overhaul-to-lower-rates/article34128778/

The IESO sets the position of the demand curve (i.e. how much DR will be bought at different prices) by setting a target quantity and price for procuring DR capacity. Recall that prior to the auction, DR was procured through bilateral contracting; those legacy contracts expire at different times, the last of these expires in 2018.[91] For the first DR auction, the IESO set the target quantity equal to the capacity that was expiring under those legacy contracts.[92] The IESO set the target price equal to the agreed upon price in those expiring contracts. In effect, the quantity of DR procured for 2016, and the price at which it was procured, was largely determined by market conditions that prevailed when those legacy contracts were signed (upwards of five years prior in some cases).[93] The IESO plans to increase DR capacity targets in future auctions by 7% per year, with additional increases as more legacy DR contracts expire.[94] In the Panel's view, the procurement of capacity for future periods should not be based on administratively determined growth rates or the volume of contract expirations, but rather on a reasonable expectation of capacity needs during the commitment period.

Regardless of the procurement mechanism, the decision on how much capacity to procure, if any, should be directly tied to the need for capacity. The IESO recently assessed the long-term need for capacity in Ontario, noting the province's strong capacity position in its *Ontario Power Outlook* report, "Ontario will have sufficient resources to meet demand requirements generally over the next decade across all [demand] outlooks".[95] This assessment is consistent with the IESO's most recent *18-month Outlook*.[96] Indeed, even without the expected capacity contributions of resources procured through the DR auction,[97] Ontario has sufficient capacity to

[91] See slide 4 of the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf
[92] See page 3 of the IESO's approved Market Rule Amendment Proposal (MR-00416-R01), available at: http://ieso.ca/Documents/Amend/mr2015/MR_00416_R01_Amendment_Proposal%20v5.0.pdf
[93] See slide 10 of the Ontario Power Authority's April 2014 presentation: *Demand Response Programs in Ontario*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/drwg-20140403-DRWG-OPA-Presentation.pdf
[94] See slide 3 of the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf
[95] See page 11 of the IESO's *Ontario Power Outlook*, available at: http://www.ieso.ca/Documents/OPO/Ontario-Planning-Outlook-September2016.pdf
[96] See page ii of the IESO's *18-Month Outlook,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18monthoutlook_2016sep.pdf
[97] The IESO's target procurement capacity for the DR auction is 648 MW in 2018, growing to 1,246 MW in 2025. For more information see the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at:

meet its needs for many years. Based on the IESO's most aggressive demand outlook (plus a reserve margin), and without any contribution from the DR auction, Ontario has sufficient capacity to meet its capacity needs until 2021. Under the most conservative demand outlook, Ontario has sufficient capacity until 2025.

Accordingly, the IESO is procuring capacity through the DR auction at a time when capacity is not needed. This procurement comes at a significant cost: resources procured through the 2016 and 2017 DR auctions will be paid upwards of $73 million in total. Under the most aggressive of assumptions, additional capacity is not needed until 2021. Fortuitously, the technology-neutral capacity auction in development is expected to have its first capacity auction in 2020 to procure capacity for future years.[98] Not only is the technology-neutral capacity auction a more cost effective way to procure capacity, but the timing of its implementation aligns far better with Ontario's capacity needs. [99]

In this regard it is noteworthy that various other capacity procurement projects have been cancelled or scaled back in recent years, including round two of the Large Renewal Procurement process,[100] and rounds five and six of the Feed-In Tariff program.[101]

Recommendation 4-2:

The IESO should reassess the value provided by the capacity procured through its Demand Response auction in light of Ontario's surplus capacity conditions, as well as the stated preference of the government and the IESO (through its Market Renewal initiative) for technology-neutral procurement at least cost.

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http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf

[98] See slide 44 of the Brattle Group's December 2016 presentation: *IESO Market Renewal Benefits Case: Preliminary Benefits Case Findings*, available at: http://ieso.ca/-/media/files/ieso/document-library/engage/me/me-20161219-preliminary-benefits.pdf?la=en

[99] As part of its reasoning for implementing the DR auction, the IESO stated the auction will, "Provide a stable transition [from bilateral DR contracts] that offers a learning opportunity for DR providers to be able to successfully compete in a full capacity auction." While that may be true, that learning opportunity comes at a cost that will well exceed $100 million, all the while providing little benefit. For more information on the IESO's justification for the DR auction, see its Market Rule Amendment Submission (MR-416-Q00), available at: http://www.ieso.ca/Documents/Amend/mr2015/MR-00416-Q00.pdf

[100] See the Minister of Energy's Letter to the IESO, dated September 27, 2016, available at: http://www.ieso.ca/-/media/files/ieso/document-library/ministerial-directives/2016/directive-lrpii-efwsop-20160927.pdf?la=en

[101] See the Minister of Energy's Letter to the IESO, dated December 16, 2016, available at: http://www.ieso.ca/-/media/files/ieso/document-library/ministerial-directives/2016/directive-nug-20161216.pdf?la=en

TAB 3

OEB STAFF INTERROGATORY 8

INTERROGATORY

Ref: Presentation to IESO Board - IESO Market Rule Amendments: Transitional Capacity Auction, August 28, 2019, p.6

Questions:

(a) IESO staff notes at slide 6 in the presentation that "Access to energy payments for DR resources with a capacity obligation has not been material historically nor is it expected to be material under the TCA rules for the December 2019 auction". Please explain this statement, including the meanings of "access" and "material" in this context.

Further on slide 6, IESO staff also notes "Economic activations of DR resources have been very limited to date, and we do not expect the likelihood of economic activation to increase appreciably in 2020".

(b) Please clarify the number of economic activations of DR resources in each year since the DRA was introduced in 2015 for: (1) HDR resources; and (2) Dispatchable load resources.

(c) Please describe the IESO's expectations for 2020 in relation to the number of economic activations of DR resources under the current TCA design. Please describe the anticipated market conditions (such as total load, MCP and/or HOEP) at times when activations, if any, would be expected.

(d) Would IESO expect the frequency of activations to change if DR resources received an energy payment and, if so, how?

RESPONSE

(a) In the referenced statement, the term "access" means an opportunity for a DR resource to receive an energy payment if activated. The IESO stated that access has not been historically "material" because HDR resources have only been economically dispatched on one occasion since the introduction of the DRA in 2015 and dispatchable loads have been dispatched less than 1% of the time over that same time period.

Based on the historical infrequency of DR resource activation in the DRA, and the IESO's short-term forecast for capacity need, the IESO estimates a very low probability of economic DR resource activation during the December 2019 TCA commitment period. Given this low probability of DR resource activation, theoretical access to energy payments should have no material impact on DR auction offers, and so would have no effect on their competitiveness in the auction.

(b) The number of activations under the DRA by year are shown on the table below for DL resources only.

	Activation (Interval Based)	Percentage of All Intervals within hours of availability (Interval Based)	Activation (Hourly Based)	Percentage of all hours within hours of availability (Hourly Based)
2016 (Since May 1st)	244	0.40%	74	1.45%
2017	142	0.20%	44	0.72%
2018	79	0.10%	34	0.49%
2019 to date	64	0.09%	23	0.38%
Total	529	0.18%	175	0.72%

Where:

- Activation (Interval Based) – Occurrences (count of intervals) that DLs were activated
- Activation (Hourly Based) – Occurrences (count of hours) that DLs were activated

Percentage of all hours within hours of availability - percentage of all hours within the availability window of the mentioned period

There has only been one activation for three hours of an HDR resource, this occurred in July, 2019.

(c) The IESO does not anticipate any change in the frequency of activations for the December 2019 commitment. There has been no material change in the target capacity for the December 2019 commitment period (675 MW for summer and winter commitment periods) as compared to the December 2018 commitment period (611 MW for summer and 606 MW for winter). The total target capacity is negligible in the context of total system need.

The IESO does not anticipate any activations of HDR resources during the December 2019 commitment period.

The IESO does not anticipate any activations of HDR resources and anticipated a similar historical activation of DL resources during the December 2019 commitment period.

(d) No. For the reasons described in paragraph (a), the IESO would not expect any energy payments to be material in respect of the December 2019 commitment period. Therefore, the IESO does not expect that the availability of an energy payment would influence frequency of activations of DR resources. As Navigant stated in section 3.1.5 of its report (Exhibit "I" to the Affidavit of David Short sworn October 25, 2019, "[l]arge 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".

TAB 4

DR STAKEHOLDER PRIORITIES FOR 2017

Demand Response Working Group

January 31, 2017

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Objective

- The objective of this presentation is to consolidate stakeholder priorities received and ensure it is documented accurately
- The purpose of this presentation is not to discuss the merits of each priority item but to ensure the feedback has been documented correctly

Introduction

- The IESO thanks all stakeholders who have taken the time to submit their DR priorities for 2017
- The IESO considers all feedback items
- Over 2016, the IESO has successfully implemented a number of stakeholder-driven initiatives:

Capacity Obligation Transfer	Target Capacity Growth Trajectory	Randomized Control Trials for RDR

Framework to Record Feedback

- The IESO has categorized all the feedback received into three broad categories that reflect the primary decision making authority:

1. **External to the IESO**
2. **Broader Market Impacts**
3. **IESO and DRWG**

- The categorization distinguishes each feedback item by decision-making authority

External to the IESO

- "External to IESO" decision items are those items where the IESO Markets team responsible for DR has limited or no decision-making authority over the change process
- On these items, the IESO can potentially facilitate discussion with key interested parties
- IESO will work with stakeholders to ensure alignment going forward

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Stakeholder Priorities: External to IESO

1. ***Easy access to residential measurement data***

- Streamlined, simple process for 3rd party providers to access residential customer measurement data without partnership with an LDC
- Concerned Green Button "Connect My Data" may be implemented differently by every LDC, making it harder to use across LDCs
- Direct access by third parties to the MDM/R for residential DR purposes

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Stakeholder Priorities: External to IESO

2. ***Commitment to DR Auction capacity and growth within the Long-term Energy Plan***

- The 2013 LTEP sets a target for DR to be 10% of peak demand by 2025
  - LTEP's definition of demand response includes Industrial Conservation Initiative (ICI), Time-of-use, etc.
- Ensure other forms of "Demand Response" do not squeeze out capacity in the DR Auction
- Consider dispatchable DR capacity before embarking on new procurements

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Broader Market Impacts

- Broader IESO priorities are related to broader market systems and processes that apply to all energy resources are not specifically for demand response
- Changes will require internal and external stakeholdering

Stakeholder Priorities: Broader IESO

1. ***Reduce 1 MW minimum size for energy resources to 100 KW***

- Reducing minimum size for energy resources will allow greater participation from the residential sector

2. ***Peaksaver transition***

- Optimize use of existing Peaksaver devices
- Ensure value of Peaksaver resource is not lost
- Implement a pilot program to transition Peaksaver resources

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Stakeholder Priorities: Broader IESO

3. *Reciprocal Settlement terms*

- Market Participants must submit Notice of Disagreements within 4 business days of the Preliminary Settlement Statement (PSS) but the IESO is not subject to the same deadline

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IESO and DRWG

- Priorities that are directly related to DR processes and procedures with limited broader market impact and where the IESO has direct decision-making authority
- Changes will still require internal and external stakeholdering

Stakeholder Priorities: DR Auction

1. ***Preparation for future Incremental Capacity Auction***

- Evolve the DR resource to help meet changing system needs
- Transition/integrate DR resources into ICA

2. ***Allow DR Capacity Obligation transfers within a commitment period and between zones***

- Obligation transfers are permitted only during the forward period
- Allow transfers to occur during the commitment period and between zones within their respective limits

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Stakeholder Priorities: DR Auction

3. ***Eliminate virtual zonal DR limits***

- Virtual limits restrict the amount of aggregated resources that can clear an auction in a zone
- Eliminate virtual limits and only apply a single zonal limit for both physical and virtual resources

Stakeholder Priorities: DR Auction

Commitment Period

4. ***Allow longer Commitment Periods***

- Commitment periods are currently 6 months in duration
- Allow some amount of DR capacity to be committed longer than 1 year through the DR Auction

5. ***Allow DR Capacity Obligations to vary on a monthly basis***

- Currently DR Capacity Obligations are fixed for a 6-month commitment period
- Allow DR Capacity Obligations to vary on a monthly basis

Stakeholder Priorities: DR Auction Administration

6. ***Implement a more efficient contributor management data entry system***

- For C&I HDR resources, contributors are currently entered manually, one contributor at a time
- A more efficient system would make the process easier for aggregators

7. ***Implement automated data submission (not via OnlineIESO)***

- IESO requests clarification from participants on this item

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Stakeholder Priorities: DR Auction Administration

8. ***Change requirement for record of installation (ROI) for all HDR C&I contributors***

- Less stringent requirements to recognize barriers faced by C&I HDR participants
- Requirement should be changed to best-efforts basis or a threshold-based requirement

Stakeholder Priorities: DR Auction

Utilization

9. Allow dispatchable loads to be contributors to an HDR resource

- Modify IESO systems to allow dispatchable loads to participate simultaneously as an energy market resource and as a contributor to an energy market resource

10. Send automated notification of standby and activation notices to Market Participant so they do not have to log-in to IESO portal

- DRMPs are required to check their private participant reports for standby and activation notices

Stakeholder Priorities: DR Auction

Utilization

11. Maintain day-ahead standby notice for HDR resources

- The IESO clarifies that the current standby notice deadline is 7am EST of the dispatch day and not in the day-ahead

12. Shorten or eliminate standby notice for HDR resources

- Standby notice is not necessary for DR resources
- DR should become a more flexible resource
- Other jurisdictions (PJM, Alberta, ERCOT, ISO-NE) do not provide a standby notice

Stakeholder Priorities: DR Auction

Utilization

13. Duration of activations should reflect system need

- Mandatory 4-hour activation block does not reflect system needs
- Allow a minimum 1 hour dispatch time

14. Reinstate utilization payments for DR activations

- HDR resources are not compensated for DR activations
- Other jurisdictions (ISO-NE, NYISO, PJM) provide both energy and availability payments to DR

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Stakeholder Priorities: DR Auction

Utilization

15. Increase test dispatch structure

- IESO requests greater clarity from stakeholders on this feedback item

IESO Priorities

1. ***Alignment with Incremental Capacity Auction development***

- Evolution of DR should be consistent with ICA design

2. ***How HDR resources are called upon in the energy market***

- Review activation requirements
- Review 4-hour dispatch block

3. ***Further integration of residential DR resources***

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Summary of Stakeholder Priorities

Category	Item
External to IESO	Easy access to residential measurement data
	Commitment to DR Auction capacity in LTEP
Broader IESO	Reduce minimum energy market resource size
	Peaksaver transition
	Reciprocal settlement terms for IESO and MPs
DR Auction	Preparation for future Incremental Capacity Auction
	Allow capacity transfers within commitment period and between zones
	Eliminate virtual zonal DR limits
	Longer commitment periods for some DR
	Varying DR Capacity Obligations
	More efficient contributor management data entry process for aggregated resources
	Automated measurement data submission capability
	Less stringent ROI requirements
	Allow dispatchable loads to be contributors in HDR resources
	Automated notification for standby and activation notices
	Maintain standby notice
	Eliminate or shorten standby notice
	More flexible dispatch duration
	Utilization payment
	Improved test dispatch structure

Next Steps

- Please ensure the IESO has captured all feedback items accurately
- To provide feedback, please contact engagement@ieso.ca as soon as possible to have a priority item considered for the 2017 DR workplan

TAB 5

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**

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TAB 6

Utilization Payments – 2017 Work Plan Item

Demand Response Working Group

Gordon Drake

May 30, 2017

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

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

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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 7

UTILIZATION PAYMENTS – 2017 WORK PLAN ITEM

Scope of Discussion Paper

July 21st, 2017

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Update

- The topic of utilization payments for demand response was selected by stakeholders to be part of the 2017 DR work plan as a discussion item
- At the May 30th DRWG, the IESO informed stakeholders of the plan to engage with an independent consultant to produce a discussion paper on the merits of utilization payments to facilitate further discussion
  - The IESO presented initial scope topics and invited stakeholder feedback

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Discussion Paper Scope

- The purpose of the discussion paper is explore whether utilization payments can facilitate greater economic participation of HDR resources
- After incorporating stakeholder input, the discussion paper scope is:
  - **Jurisdictional review** - A summary of practices that are adopted in other markets
  - **Economic efficiency** - Arguments for/against providing a utilization payment to DR resources in light of current and future system needs
  - **DR Participation** – The likely impacts of utilization payments to the dispatch frequency of HDR resources in Ontario
  - **Wider market impacts** - Spillover effects on the wider market

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Next Steps

- Navigant has been selected as the consultant to produce the discussion paper through an RFP process
- The discussion paper is expected to be completed in Q3 and will be posted on the DRWG webpage
- Utilization payments will be an agenda item at the next DRWG meeting once the discussion paper is posted

If you have any questions or feedback,

please submit to engagement@ieso.ca

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TAB 8

Demand Response Discussion Paper

Utilization Payments

Prepared for:

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December 18, 2017

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

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[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.

<u>Considerations for Ontario:</u> 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.

<u>Considerations for Ontario:</u> 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.

Considerations for Ontario: 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]

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[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?
Texas (ERCOT)	Ancillary	Synchronized reserve, Frequency regulation	10 min or 30 min	Spot price for service	Ancillary services market
	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

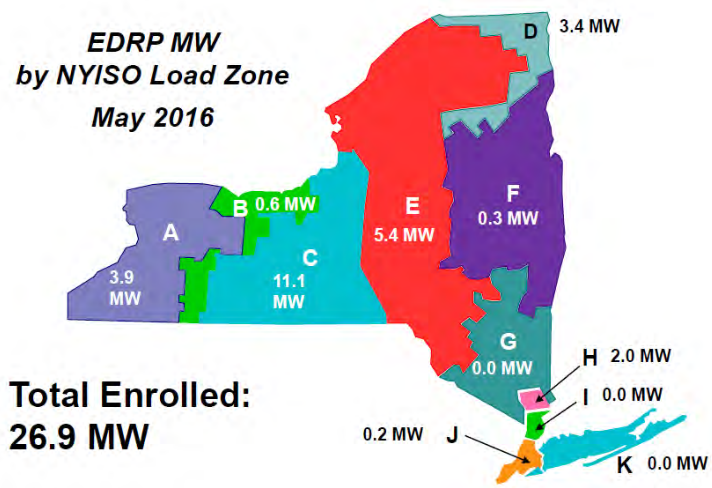
Category	Capacity Market	Energy Market
Program Period	Annual (can bid seasonally or monthly)	Annual (bid at will)
Event Windows	Anytime	Based on bidding and clearing
Dispatch Limits	4 hours	Based on bidding and clearing
Notification Time	Day-ahead and 2-hours prior	Day-Ahead or Real-Time, based on bidding 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)

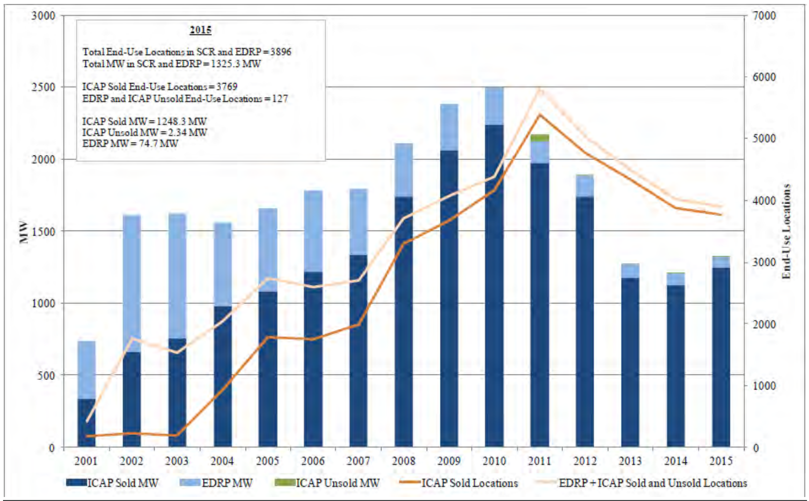
Payment: Monthly Capacity payments are based on sales made through ICAP auctions or bilateral contracts. The energy payments are based on performance in events & tests; Locational Based Marginal Pricing (LBMP) with daily guarantee of strike price recovery.

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.

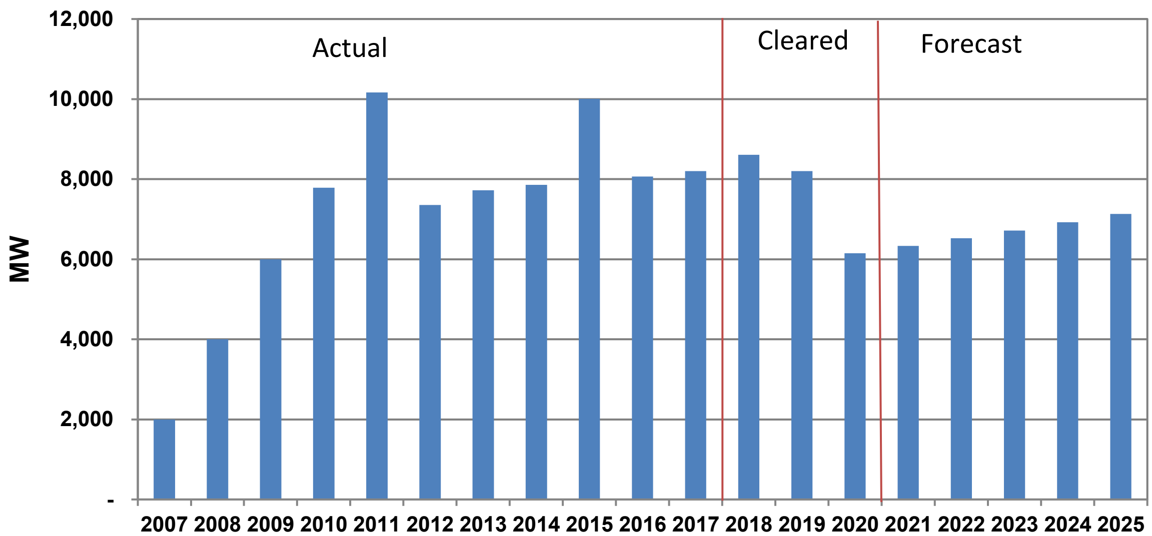
Payment: Resources are paid marginal clearing prices for Ancillary Service product scheduled. This price is based on auction clearing price which is dependent on location and the product.

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

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[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.

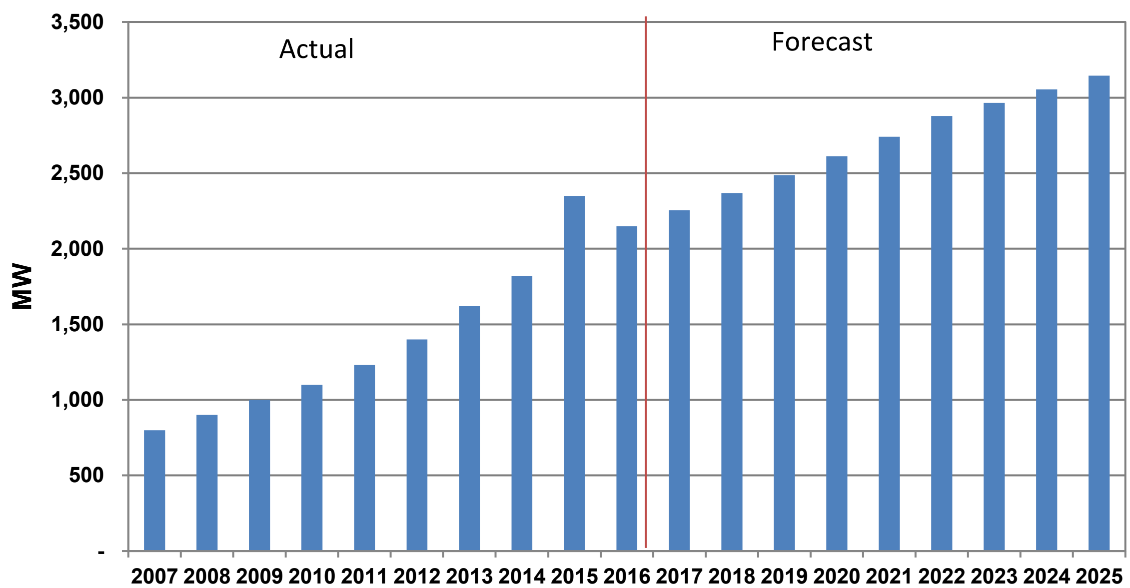
SCE offers the ***Scheduled Load Reduction Program (SLRP)*** to qualified bundled-service customers whose average monthly demand is 100 kW or more. The program provides a $0.10 per kWh on-bill credit for reducing load on prescheduled days and times on weekdays from June 1 through September 30.

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.

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[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.

[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.

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[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 9

DEMAND RESPONSE DISCUSSION PAPER

UTILIZATION PAYMENTS

NOVEMBER 16, 2017

NAVIGANT

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.

ARGUMENTS FOR AND AGAINST UTILIZATION PAYMENTS

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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

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

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

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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.

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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***.

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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.

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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.

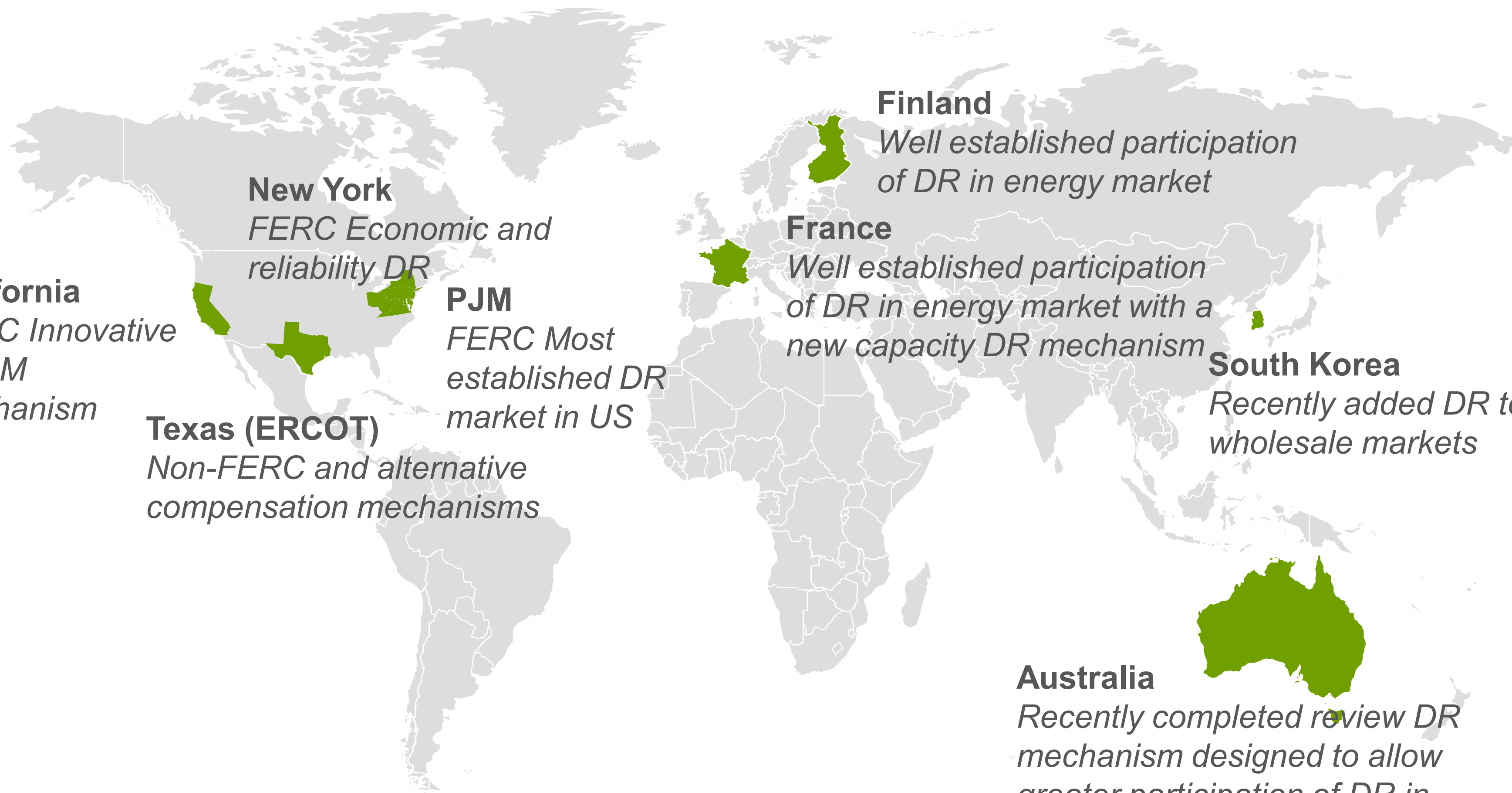
	Economic/Energy	**Reliability/Capacity**
Receives availability payment	No	Yes
Receives utilization payment	Yes	Maybe
Voluntary availability	Yes	No

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

JURISDICTION SCAN OVERVIEW



NAVIGANT

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**

NAVIGANT

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)

NAVIGANT

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.

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

NAVIGANT

TAB 10

IESO Engagement

From: IESO Engagement
Sent: December 19, 2017 3:02 PM
To: IESO Engagement
Subject: Utilization Payments - Discussion Paper

Good Afternoon,

A notice to all DRWG members that the report on Utilization Payments prepared by Navigant (consultants) is now available on the DRWG page.

As a reminder, this report was commissioned as it emerged as a priority item in the DRWG 2017 work plan. Next steps for this particular priority is to have members review the report over the next month and engage in discussion at the January 30, 2018 DRWG meeting. Also, the IESO is calling on members to consider making short informal presentations/remarks to the DRWG at that time to further progress this review if interested.

Thank you and if you have any questions, please let us know.

Jason – IESO Engagement

TAB 11

UTILIZATION PAYMENT DISCUSSION PAPER

Demand Response Working Group

January 30, 2018

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Purpose

- To facilitate a discussion with questions on the key arguments and observations from the Navigant Demand Response Discussion Paper on Utilization Payments
- Hear representations from stakeholders for IESO to better understand perspectives, concerns and rationales on this issue
- Determine whether and how best to proceed

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Utilization Payments - Background

- Utilization Payments has been a recurring topic of discussion by stakeholders in the DRWG and was 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 discussion paper authored by Navigant was published in December 2017
- Stakeholders provided input into potential topics to be included in the scope of the discussion paper

Re-cap of Scope

- The paper provides research on utilization payments within the following framework

Economic Efficiency	• Arguments for/against providing a utilization payment to DR resources in light of current and future system needs
DR Participation	• The likely impacts of utilization payments to the dispatch frequency of HDR resources in Ontario
Wider Market Impacts	• Spillover effects on the wider market
Jurisdictional Review	• A summary of practices that are adopted in other markets

Considerations for Ontario

- The Paper does not include formal conclusions or recommendations.
  - For each of the arguments presented, the Paper outlines considerations for Ontario which may affect the applicability and materiality of some of the issues discussed
- IESO is interested in better understanding how members view these observations and what is instructive for the DRWG to consider further
- Next slides outline some of the key considerations and questions for further discussion

Overview of Arguments

- Paper reviews common arguments put forward by proponents and detractors on merits the issue

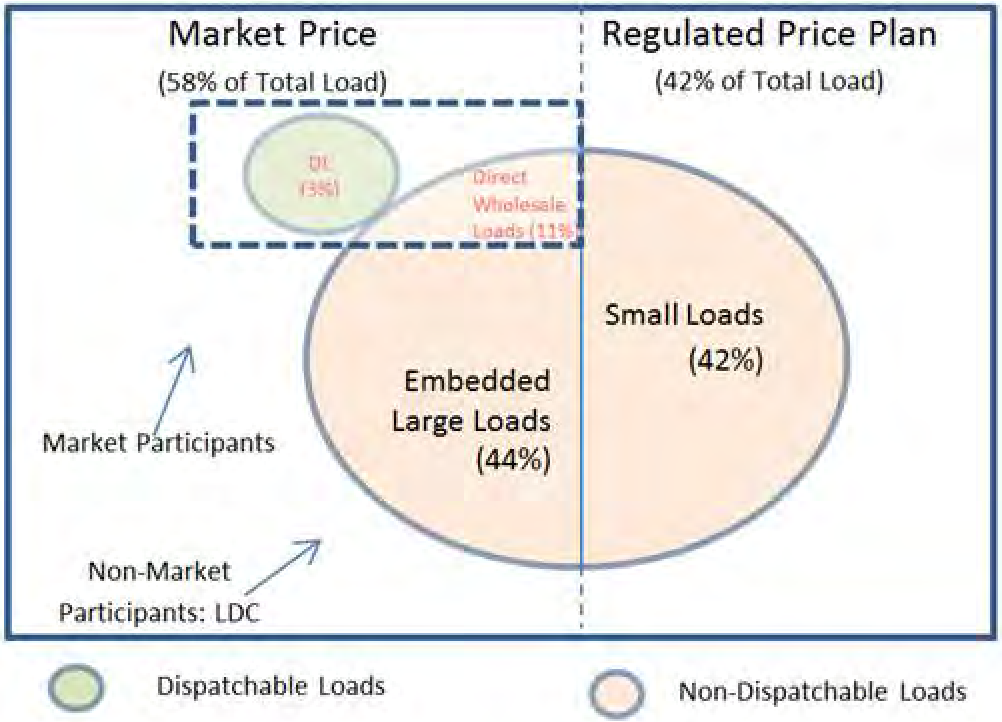
Against	*For*
• Wholesale Price Efficiency • Disproportional Benefits • Harm to Other Suppliers • Harm to Economy	• Reducing Consumer Costs • Disconnect between Wholesale and Retail Prices • Fairness • Other Costs Associated with Curtailment

Discussion: Where to go from here?

- IESO is looking for compelling rationales from the DRWG on the merits of DR utilization payments
  - Need feedback and arguments on whether the DRWG should continue to pursue the utilization payment issue and why?
- IESO and stakeholders will also need to consider the broader implications of this issue beyond the DRWG (and Market Renewal and the ICA in particular)
- Out of this Discussion Paper, the IESO has some initial questions for the working group on the materiality and impact of utilization payments

Discussion – Market v. Retail Price

- The Paper notes that a number of the arguments are contingent upon whether customers pay the market price for electricity or are on retail rates



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

Arguments

Against: Wholesale Price Efficiency	*For*: Disconnect Between Wholesale and Retail Prices
• Price-responsive loads determine whether it is more cost-effective to operate or curtail based on market price signal	• Customers on regulated price plans are not exposed to real-time signals • Utilization payments may improve efficiency of retail price as additional incentive during periods of high market prices

Discussion Questions

- *What are members' views on these arguments?*
- *How applicable is the market v. retail pricing issue to HDR resources?*
- *What proportion of existing DR contributors are exposed to market price v. retail price?*

Discussion – Utilization Frequency v. Cost of Activations

- The Paper notes that the arguments depend a great deal on whether utilization payments result in a considerable increase in activations
- These arguments are also closely tied to the cost of curtailment, ie the value of lost load (VOLL)

Arguments

Against:	*For:*
• Payments may lead to greater activations →putting downward pressure on prices →negatively impacting other suppliers	• Increased DR participation/lower energy prices • There is a cost associated with curtailment (**value of lost load**), which can be higher than avoided cost

Discussion Questions

- *What impact do members believe utilization payments would have on their own energy bid prices?*
  - *Lower bid prices may increase frequency of activations and overall participation*
  - *Would energy bid prices be lowered to the point where utilization is impacted?*
    - *The IESO provided historical price observations at its Sept 12 DRWG meeting:* http://www.ieso.ca/-/media/files/ieso/document-library/working-group/demand-response/drwg-20170912-update-improved-utilization-dr.pdf?la=en
  - *How does it change by type of load?*
  - *How are VOLL considerations currently reflected in bids into the energy market?*

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Discussion – Fairness and Equity

- The Paper also considers utilization payments in a broader context of fairness and equity

Arguments

Against:	*For:*
• Utilization payment compensates DR disproportionately because DR resource did not incur a cost associated with the production of electricity (**negawatt ≠ megawatt**)	• Generators receive a utilization payment via an energy payment; should DR should be treated consistently and receive curtailment payment?**(negawatt = megawatt)**

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Member Representations/Discussions

- Interested in hearing member perspectives and observations
  - *What arguments did members find compelling and why?*
  - *Are there areas which require further analysis/discussion?*

Next Steps

- Please send any additional feedback by February 13 to engagement@ieso.ca
- This feedback will help IESO make a determination on how to proceed on this issue for 2018

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TAB 12

IESO Engagement

From: IESO Engagement
Sent: February 12, 2018 3:19 PM
To: IESO Engagement
Subject: DRWG - Call for Feedback and Next Meeting Registration

Good Afternoon DRWG members!

A friendly reminder to all DRWG members that that the IESO is looking for feedback by end of day tomorrow for discussion topics from the January 30 DRWG session to help advance the priorities and development of a 2018 work plan which will be presented at the March 1 meeting. As an aside, if you have not registered for the March 1 meeting yet, please do so now by emailing engagement@ieso.ca. The March 1 meeting is scheduled to take place at the Four Points by Pearson Airport. The meeting time is currently set for 9:30 am to 3 pm.

For more information or as a reminder of the discussion topics covered on January 30, please review the presentations on the DRWG page.

Please let us know if you have any questions.

Thanks – Jason
IESO Engagement

TAB 13

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

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

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*

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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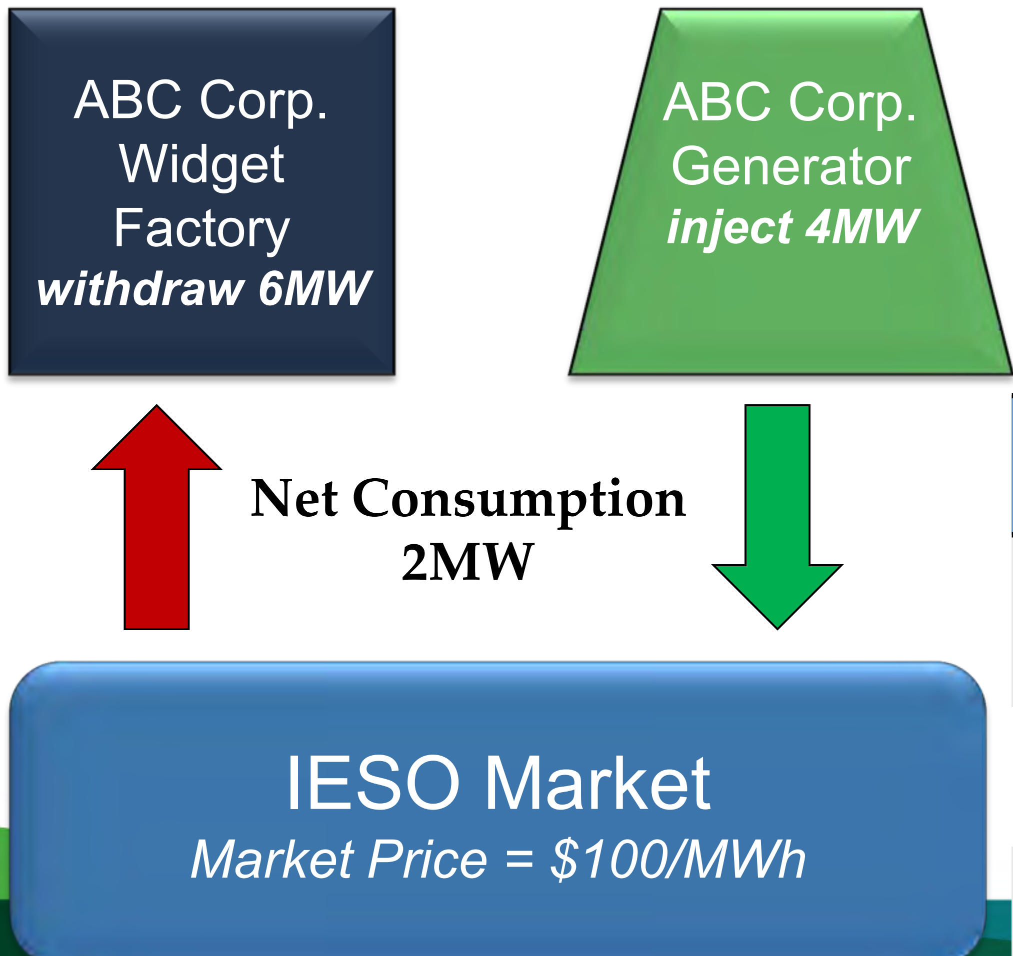
Negawatts and Megawatts

IESO Example 1

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

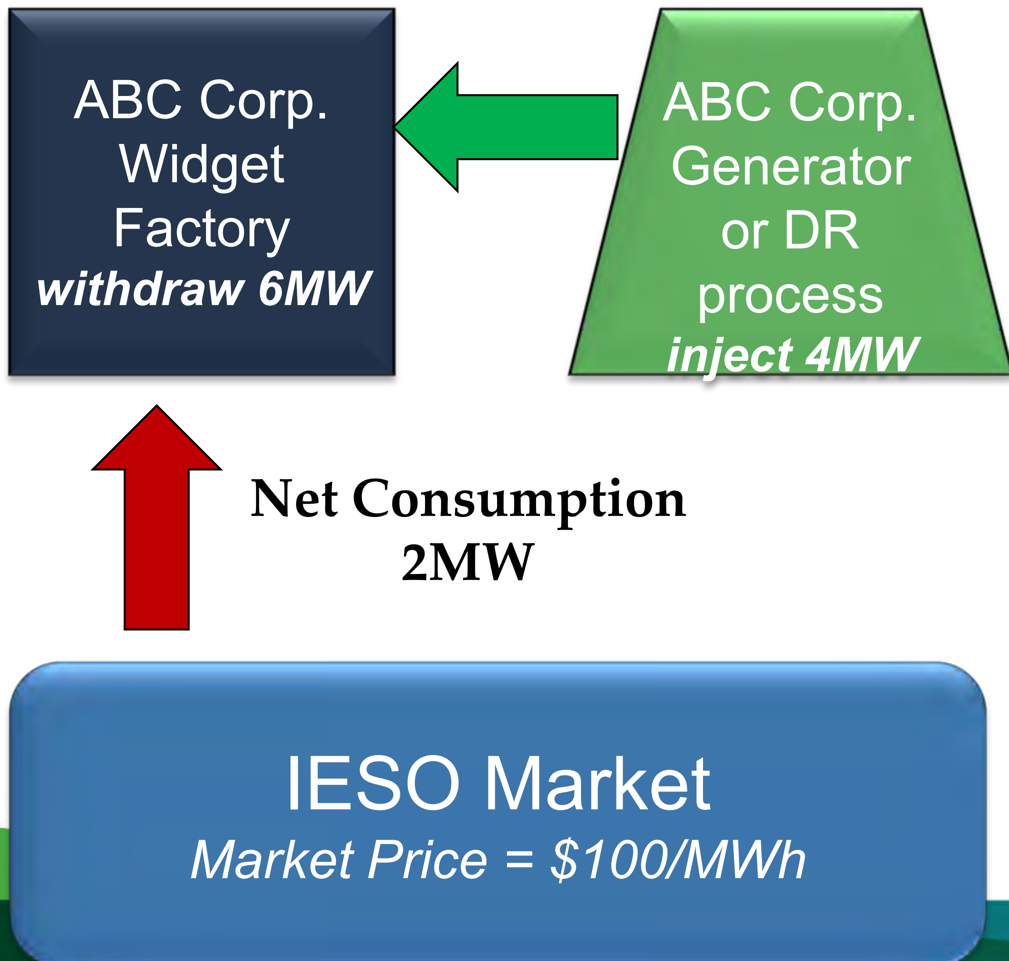


ABC Corp. Energy Bill	
Net Consumption MW	2MW (6MW-4MW)
Energy Price	× $100
Net Settlement	**$200**

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

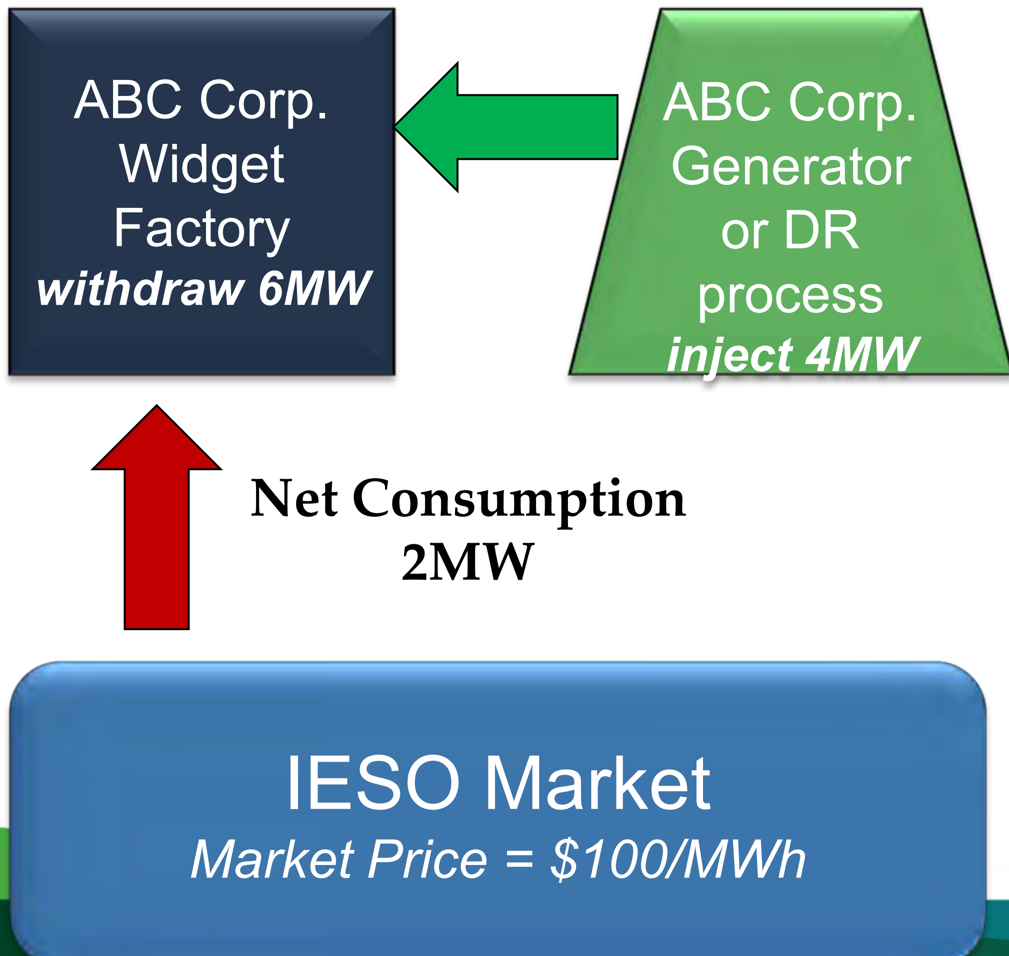


ABC Corp. Energy Bill	
Net Consumption MW	2MW (6MW-4MW)
Energy Price	× $100
Net Settlement	**$200**

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

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 14

Demand Response Working Group (DRWG)
Meeting Notes - March 1, 2018

Meeting Notes

Date held: March 1, 2018	**Time held:** 10am to 3pm	**Location held:** Four Points Toronto Airport
Company Name	**Invited/Attended**	**Attendance Status** (A)ttended; (R)egrets; (S)ubstitute
Alectra	Carr, Daniel	A
AMP Energy	Luukkonen, Paul	A
City of Toronto	Koff, Chaim	A
City of Toronto	Poto, Angelo	R
Compass Energy Consulting	MacDougall, Jim	R
EnerNOC, Inc.	Griffiths, Sarah	A
Great Circle Solar Management Corp.	Wharton, Karen	A
Honeywell Smart Grid Solution	Donovan, Dan	A
Hydro One	Katsuras, George	A
Stem/Nest Labs	Amaral, Utilia	A
NRG Curtailment Solutions, Inc.	Vukovic, Jennifer	R
Powerful Solutions	Inman, Peter	A
Rodan Energy Solutions	Goddard, Rick	A
Rodan Energy Solutions	Quassem, Farhad	A
Tantalus	Tiwari, Sudhir	R
Voltus, Inc.	Strawczynski, Zygmunt	A
Registered to participate via teleconferencing		
City of Toronto	Cheng, Jessie	TC
Cpower Energy Management	Hourihan, Mike	TC
Customized Energy Solutions	Withrow, David	TC
Ecobee	Houle, Jonathan	TC
Energy Hub	Kier, Laura	TC
EnerNOC, Inc.	Chibani, Yanis	TC
Hamilton Utilities Corporation	Crown, Mike	TC
Ministry of Energy	Tomlinson, Patrick	TC
NRG Curtailment Solutions, Inc.	Popova, Julia	TC
OhmConnect	Kooiman, Brian	TC
Resolute Forest Products	Degelman, Cara	TC
Toronto Hydro-Electric Services Ltd.	Marzoughi, Rei	TC
IESO	King, Ryan	A
IESO	Kwok, Jason	A
IESO	Trickey, Candice	A
IESO	Agrawal, Vipul	A
IESO	Butterfield, Adam	A

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Date held: March 1, 2018	**Time held:** 10am to 3pm	**Location held:** Four Points Toronto Airport
Company Name	**Invited/Attended**	**Attendance Status** (A)ttended; (R)egrets; (S)ubstitute
IESO	Cowx, Christina	A
IESO	Fitzgerald, Dale	A
IESO	Grbavac, Jason	A
IESO	Matsugu, Darren	A
IESO	Zaworksi, Richard	A
Scribe: Name of scribe Please report any corrections, additions or deletions e-mail to scribe.		

All meeting material is available on the IESO web site at: www.ieso.ca/drwg

Item 1 – 2018 DR Work Plan

Ryan King provided the members of the DRWG with a review of the proposed work plan items including those items submitted as feedback since the last DRWG meeting in January. The goal of the presentation was to finalize the 2018 DRWG work plan, however, feedback and discussion on each item was encouraged. A proposed 2018 DRWG work plan was presented and stakeholders were asked to provide any feedback on that work plan by March 16.

Member Questions and Comments, *with the IESO's response in italics*:

With regards to slide 11 on the priority item Varying DR Capacity Obligations, a member asked for clarification on what is meant by the IESO when noting this would require a "change to the DR auction".
This priority item proposal speaks to changing the capacity obligation (the number of MWs) from a fixed value for a six-month period to enabling different capacity obligation values on a month-to-month basis. This would be a significant change to many design elements of the DR Auction. The auction selects the most-competitive offers for six-month seasonal commitment periods, moving away from this design would require modifications to many associated elements such as auction frequency, registration and settlement tools.

Members of the DRWG agreed that there should be further discussion on the priority item Dispatchable Loads in Aggregated Resources.
The IESO committed to have a more in depth technical discussion on this item at an upcoming DRWG meeting.

A stakeholder asked how feedback provided at the DRWG on other IESO engagements, such as the ICA, will be passed on to those respective engagements.
The DRWG should not replace any other IESO engagements and feedback on other engagements should still be provided in their respective forums. However, the DRWG can be utilized as a forum to facilitate discussion on how ICA design decisions might impact DR. These discussions can help support transition from the DR Auction to the ICA.

A member asked how issues or concerns from the DRWG on the ICA can get added onto the ICA agenda.
The ICA is currently working through each of the design elements and has made some preliminary decisions on less contentious items. Stakeholders should continue to provide their feedback directly to that forum. Moving closer to the summer engagements the ICA will begin to discuss more resource-specific design issues (including for DR); participation in those sessions is encouraged.

A stakeholder commented that many of the mechanisms in the ICA, such as the hours of availability, standby notice, etc., are different than the ones currently in place for DR. The stakeholder wondered to what extent have past programs, such as CBDR, DR3 and the DRA, played into the design of the ICA.
The design of the ICA is still in the process of being developed with stakeholders. However, it is in the collective interest (both IESO and DRWG) to ensure that DR is able to effectively participate in the ICA. This is one of the reasons why a focus for 2018 will be on enhancing the value of DR resources in the short term because doing so will help transition DR to compete with other supply types under an ICA.

Item 2 – Market Renewal Discussion: Energy Stream

Darren Matsugu presented an overview of the Market Renewal Program Energy Workstream to the members of the DRWG. The energy workstream will improve the dispatch, commitment and pricing of resources in the energy market. Darren mentioned a new participant type within the Day-Ahead Market (DAM), price responsive loads, may be of interest to DRWG members. There are opportunities for resources that could benefit from the more localized price signals as a result of this new market.

Member Questions and Comments, *with the IESO's response in italics*:

A member asked if the IESO is expecting loads to participate in the Day-Ahead Market (DAM) in the same way generators will be.
Participation in DAM by price responsive loads is voluntary. If a price responsive load wants to participate in order to have less exposure to the real-time market prices, the opportunity is there. The IESO believes there is benefit to resources from participating and that aspect of the design would benefit from stakeholder feedback.

A stakeholder asked what percentage of the load would be facing the locational marginal price (LMP).
Approximately 14%.

Item 3 – Non-Emitting Resource RFI

Adam Butterfield from the IESO provided the members of the DRWG an update on the Non-Emitting Resource Request for Information (NER RFI). While the RFI is not part of the Market

Renewal Project (MRP), phase one of the two RFI phases is aligned to support the work of the Non-Emitting Resource Sub-Committee (NERSC) of the Market Renewal Working Group (MRWG). The final Phase 1 RFI is planned to be posted as early as March 19 and a Technical Conference will be held at the Metro Toronto Convention Centre on April 5th. Registration for the event can be found https://www.eventbrite.ca/e/nersc-technical-conference-tickets-43622227256?aff=es2 .

Member Questions and Comments, *with the IESO's response in italics*:

No comments were provided.

Item 4 – Utilization Payments

Ryan King provided the members of the DRWG with a review of the stakeholder feedback received and encouraged discussion on the merits of DR utilization payments. The IESO presented each feedback item and offered its own perspectives. The IESO is seeking compelling rationales from the DRWG on the merits of DR utilization payments in order to better evaluate this priority work plan item.

Member Questions and Comments, *with the IESO's response in italics*:

A stakeholder commented that they would be willing to share specific information on a confidential basis on how customers on the Regulated Price Plan would benefit from utilization payments.

The IESO is interested in evaluating the priority item on utilization payments appropriately and therefore would appreciate stakeholders sharing as much information as they are willing.

A stakeholder commented that they disagreed that utilization payments would not make a difference at the residential customer level.

The IESO wants to better evaluate the priority item and therefore needs detailed feedback from stakeholders to demonstrate why this might be the case.

A member commented that when utilization payments were previously in place, the payment was a large support for participation. They stated that the savings from curtailing is not as great as an incentive for activation compared to the revenue gained from a utilization payment.

The IESO requested more stakeholder feedback to better understand this statement.

A member asked if the IESO could provide clarification on the difference between a capacity payment and a utilization payment.

Participants that have cleared the Incremental Capacity Auction will receive a capacity payment for being available to be called upon for demand response. The utilization payment is in addition to the capacity payment and is only made when a DR resource is utilized.

The member then asked if an LDC would be eligible for a capacity payment if they were to run a program for smart thermostats.
If the LDC meets the requirements to participate in the auction then they would have the potential to receive a capacity payment. The capacity payment would only be received if the participant cleared the auction.

A stakeholder asked for clarification on how loads bid their opportunity costs.
Loads have the ability to submit bids for their energy reflective of their willingness to pay for electricity (and above which they would rather not consume i.e. curtail). For some loads, it is not uncommon for them to bid very near the maximum market clearing price if their opportunity cost of curtailment is very high. This however may not be the case for all resources.

A member made the comment that DR resources are different than other resources because of the requirement to be curtailed for 4 consecutive hours. Because this curtailment is based on pre-dispatch prices, the actual avoided cost savings for settlement purposes over the course of 4 hours may not result in the same amount of savings the participant initially thought. The implementation of utilization payments may change the behaviour of loads willing to participate in DR.

A stakeholder commented that the resources in the ICA will be a different product than the resources currently in the DRA. With that in mind, they are not looking to implement utilization payments for the DRA; however, they will be advocating strongly for utilization payments to be a part of the ICA.

With respect to the Negawatts and Megawatts example presented on slide 11, a stakeholder commented that the example pre-supposes a single market participant exposed to a single market price. Another stakeholder asked how many participants fit into that example and is this the exception rather than the rule?
The example is meant to illustrate that from a grid perspective, the two scenarios create the same net impact and thus should receive the same settlement treatment. The point being made in this example is that a utilization payment is in fact an unequal treatment because it provides an additional payment to a DR resource. The IESO encouraged participants to provide feedback on the examples.

A member commented that the IESO currently pays for negawatts through other energy efficiency incentives. Therefore, it is not out of the realm of the IESO's current operations to pay for the non-utilization of energy.
There may be many direct and indirect incentives from various programs to encourage participation from various resource types but this does not provide a rationale for a market operator to incorporate utilization payments into market dispatch.

A stakeholder commented that the value of lost load (VOLL) may be higher for resources during a 4 hour dispatch duration, where the VOLL may not be as high if the duration is shorter, for example 1 or 2 hours. Another stakeholder countered saying that there are participants that have a minimum dispatch time and therefore a shorter dispatch duration would not be applicable.

Item 5 – HDR Performance Testing

Candice Trickey provided the members of the DRWG with an outline of the IESO's plans for DR resource testing and ensured participant understanding of their obligations and consequences of non-performance. Since DR resources are not being used frequently, tests are necessary to ensure that they are a reliable resource. The IESO has the ability to test a resource up to twice a commitment period and will use both opportunities if the participant fails.

Member Questions and Comments, *with the IESO's response in italics*:

A member asked if the IESO will test a resource a second time if the resource failed the first test.
Yes, the IESO has the authority to test up to twice a commitment period. The aim is to test only once a period; however, if a resource doesn't pass a test then the IESO will use the opportunity to test again.
Another member commented that they disagree with tests that fail for reasons outside of the participant's control, such as aborted tests.
The IESO has the ability to test twice in a period and will use the second chance to test if it is necessary.

Item 6 – Maximizing the Value of HDR Resources through Improved Utilization

Jason Kwok provided the members of the DRWG an update on adding HDR resources to the Emergency Operating State Control Actions (EOSCA) list and proposed changes to HDR scheduling protocols to maximize value. Adding HDR resources to the EOSCA list is currently on track for the Summer 2018 commitment period with Market Manual changes expected to be posted on March 15 for stakeholder review. Jason discussed how reducing the minimum dispatch duration and improving real-time availability of HDR resources will aid in improving scheduling flexibility and the utilization of HDR resources.

Member Questions and Comments, *with the IESO's response in italics*:

A member asked in other jurisdictions where the must-run period is longer than 4 hours, is this criteria for all DR resources or other participant types as well. They also asked how this will be taken into account for the ICA.
Through the design element "Visibility and Control", the ICA stakeholder engagement will be discussing minimum dispatch durations for all resource types.

A member commented that with the change in the minimum dispatch duration, one-up-to-four hour block, and the uncertainty of not knowing whether the dispatch will be 1 hour or 4 hours is a concern. They suggested that a separate participant type be created for curtailments of only 1 to 2 hours.

The current requirement for HDR resources is to be able to remain down for 4 hours and therefore all current HDR resources should have this capability. The one-up-to-four hour block provides greater flexibility to the IESO but should not be a barrier to continued participation for existing capacity.

A stakeholder asked for the number of activations that would have occurred during the look-back period for the price-based trigger standby notice analysis.
There would have been two days with in-market activations for the Southwest, Toronto and East HDR resources over the look-back period.

The stakeholder then asked what the purpose of a standby notice is if no activation is to follow.
The purpose of the standby notice is to simply ensure that these resources are available in real-time to the system if they are needed. When capacity is being procured through the DRA or the ICA, the IESO needs to ensure that it has sufficient resources available to be called upon during all times. Currently, if an HDR resource is not placed on standby by 7 am of the dispatch day, it would no longer be available after 7 am for the IESO to utilize if the need emerges. Having DR resources more available in real-time increases the value of DR as a capacity resource.

A member commented that with the standby notice being based only on 1 hour and the dispatch duration being one-up-to-four hours, the standby is not an equivalent test to what the requirement is.
The 4 hour requirement is a barrier to getting access to the real-time availability of the resource, which is why the IESO is proposing to trigger a standby based on one hour. This will increase the availability of HDR.

A stakeholder commented that the IESO is reducing the value of the standby notice by issuing standby notices that do not result in activations. There is a cost to the resource when they are issued a standby notice and the reliability of the resource might decrease when activations are not issued after a standby notice. A member also asked how the IESO is evaluating what a successful price-based trigger is.
Ideally, the IESO would want to transition away from standby notices and require DR resources to be available in real-time every single day. At previous DRWG meetings, the IESO has discussed eliminating the standby notice so that HDR resources are available to be utilized in real-time every day. Stakeholders advised that eliminating the standby notice right away would significantly reduce their participation. Based on this feedback, at the Jan 30 DRWG meeting, IESO advised that it would not be eliminating the standby notice in 2018. However, the IESO continues to be interested in maximizing value of HDR and based on historical analysis, $100 price trigger is a good transitional step because it demonstrates strong correlation with availability at times of system peak as illustrated in the slides.

The IESO asked members of the DRWG to provide feedback on the two proposals the IESO presented to improve the utilization of HDR resources.

Next Steps

Members are asked to send any feedback from the March 1st meeting by March 16 to engagement@ieso.ca. The next DRWG meeting is an in-person session tentatively scheduled for May 3.

Note: The next in-person ICA meeting is scheduled for April 19.

TAB 15

2018 Technical Planning Conference

September 13, 2018

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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

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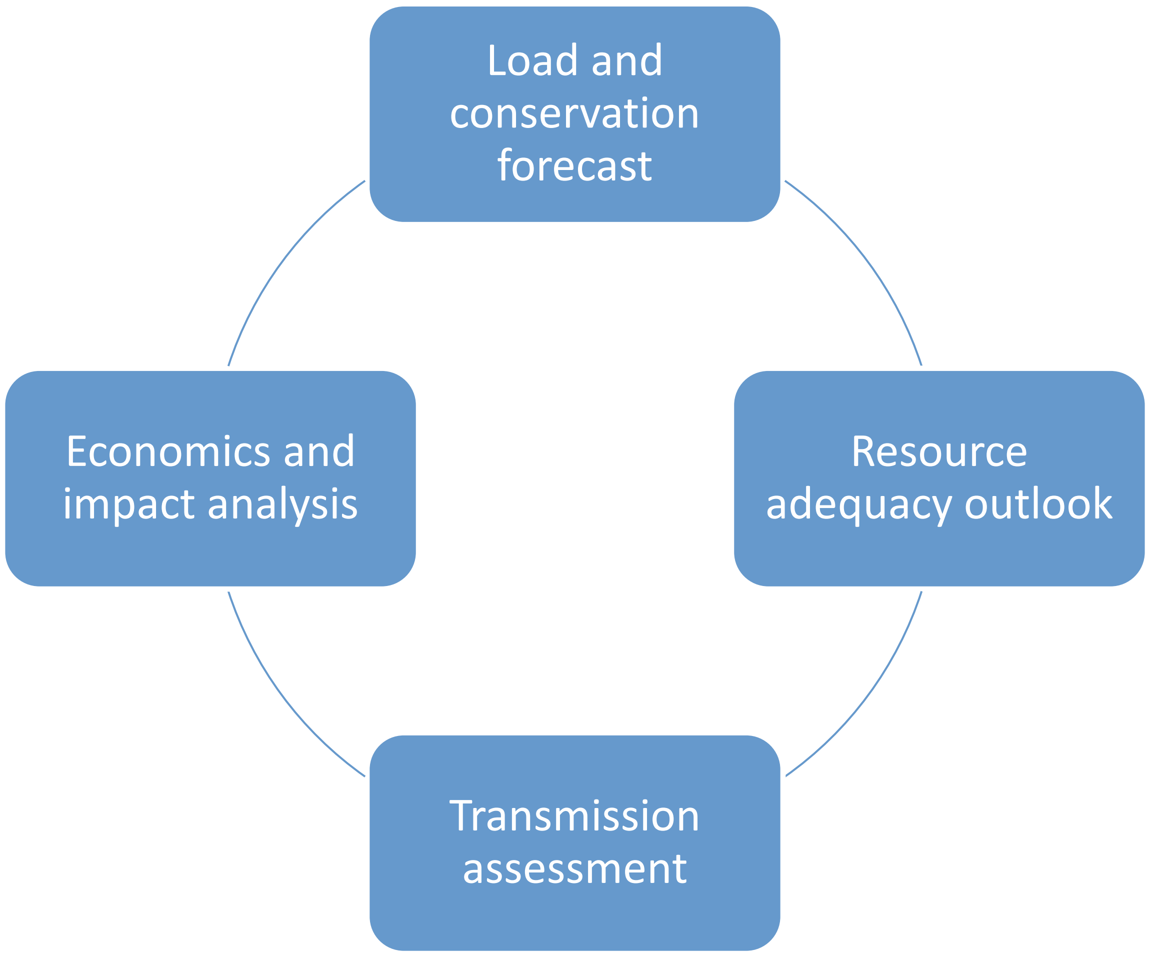
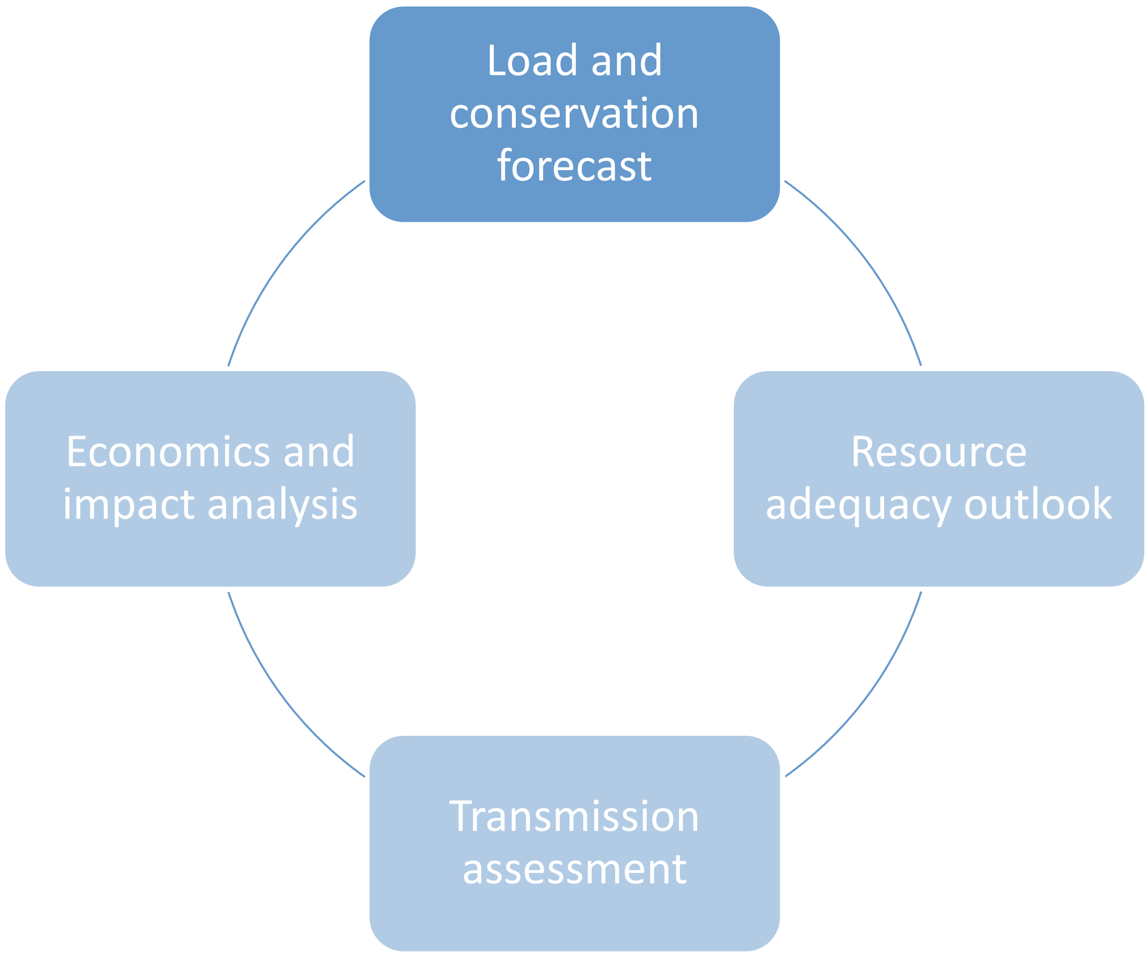
Bulk system planning process



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.

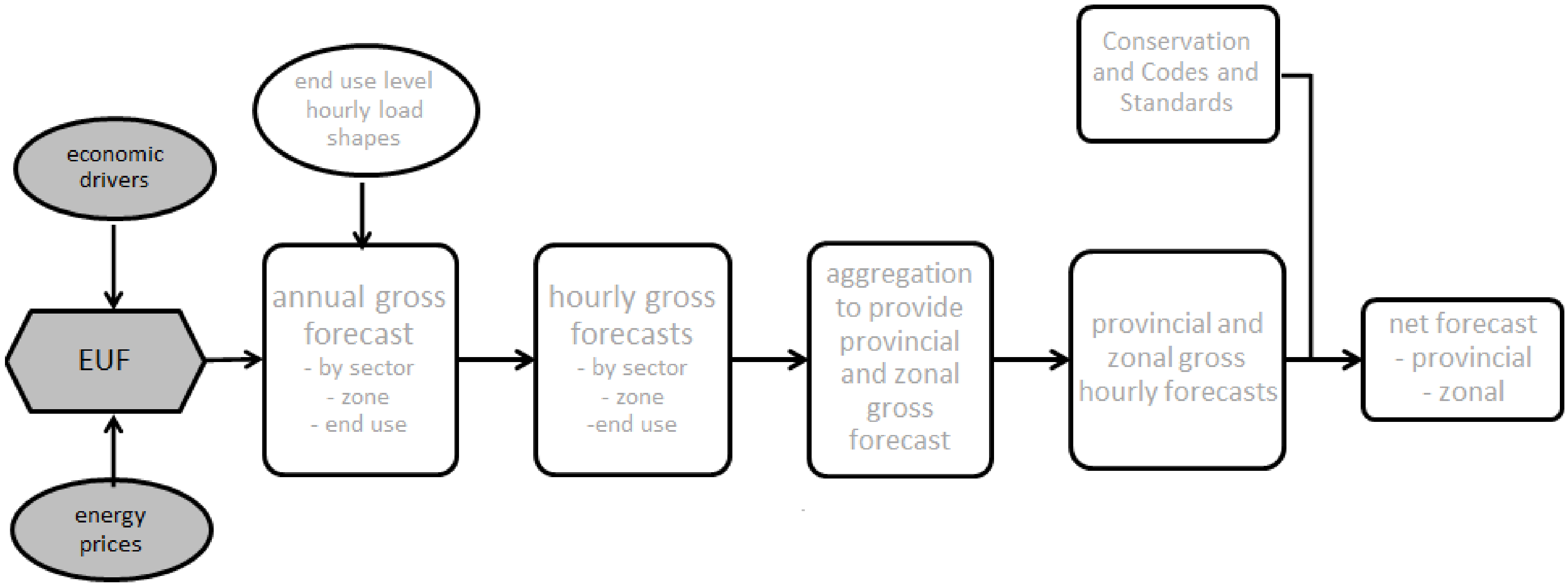
- The IESO conducts short, medium and long-term integrated power system planning for the province.

- 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



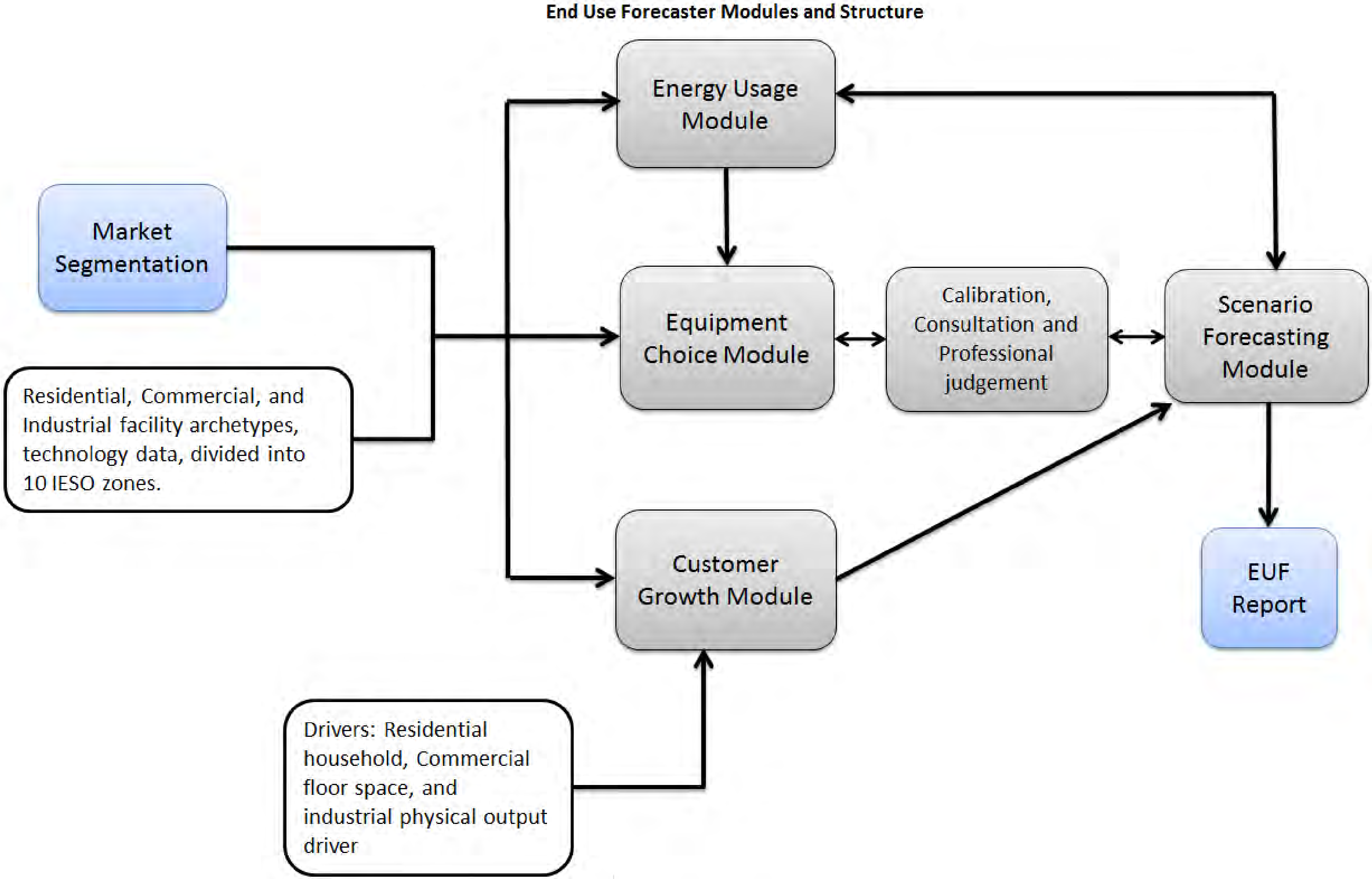
Key drivers considered for electricity demand

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

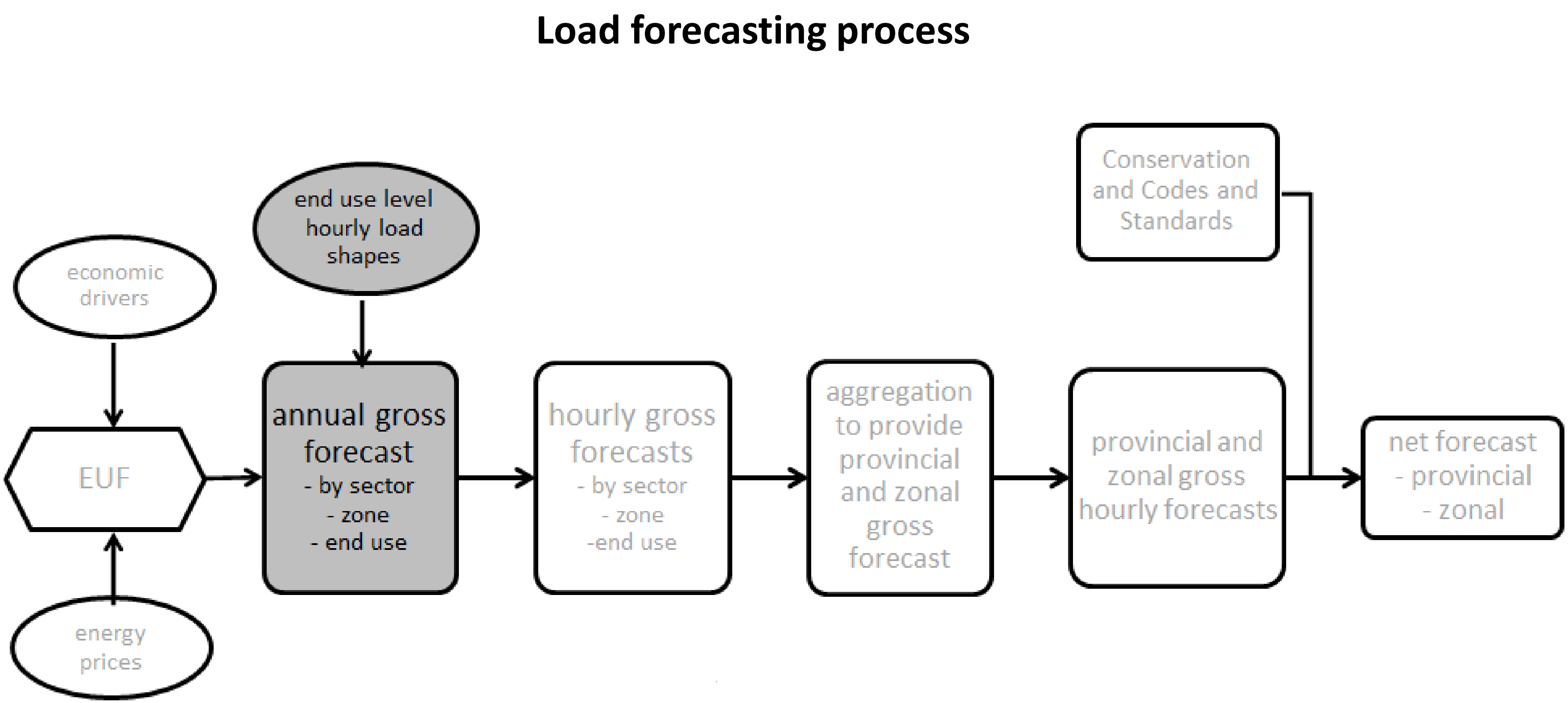
- **Electricity price and natural gas price forecast:**
  - High electricity price results in greater natural efficiency uptake
  - Rate design impacts – annualized price effect of the Industrial Conservation Initiative is included in the sector price forecast

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

End Use Forecaster (EUF) model schematic

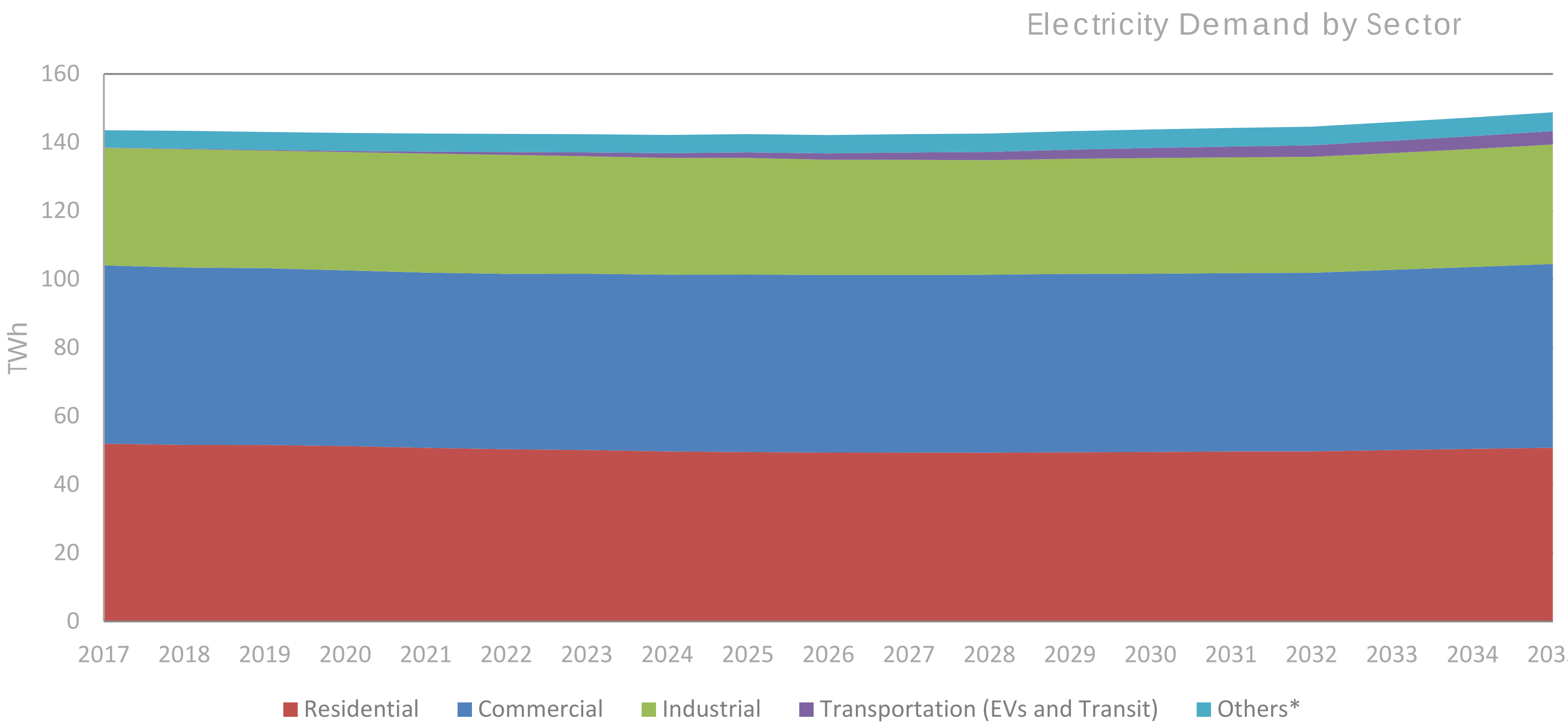


How we develop long term load forecast



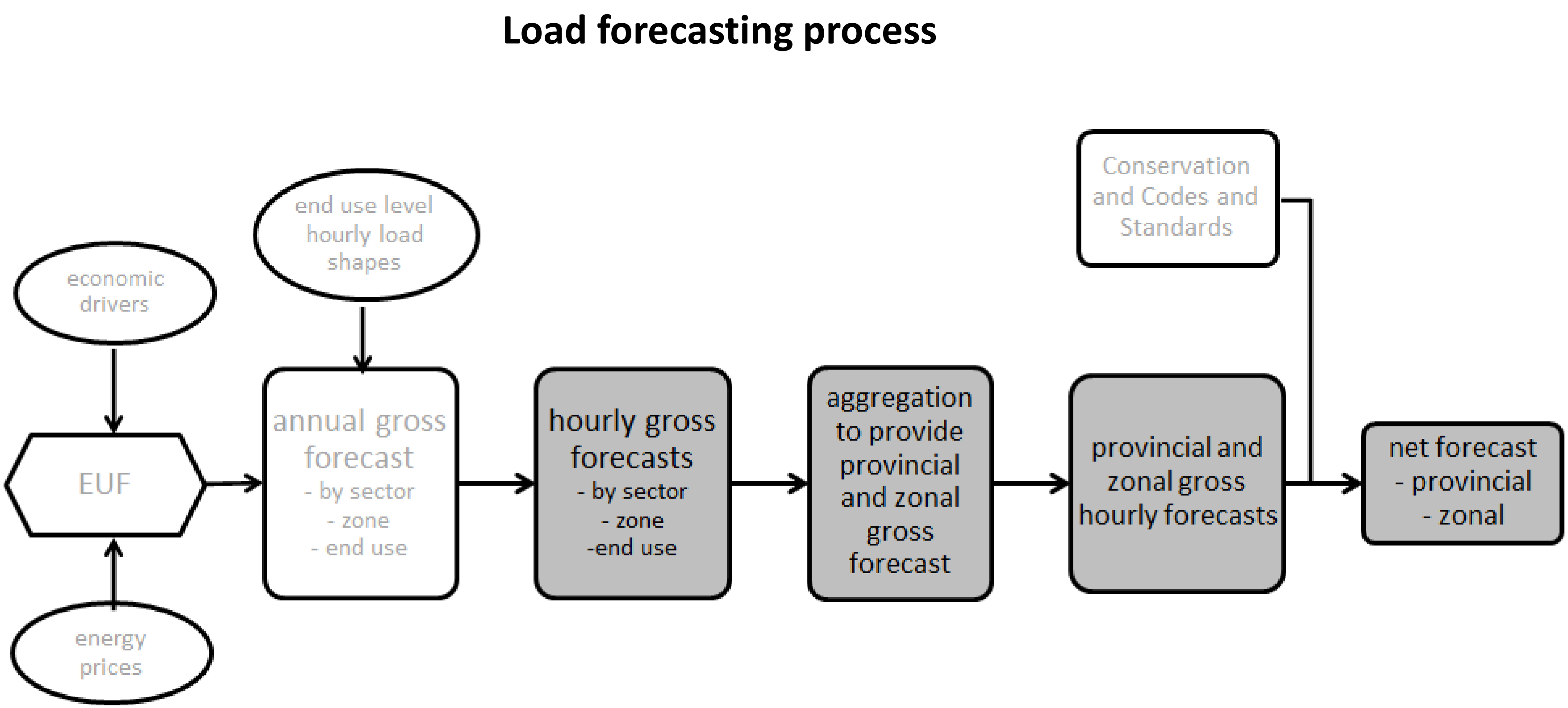
Demand sector – Reference Forecast

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



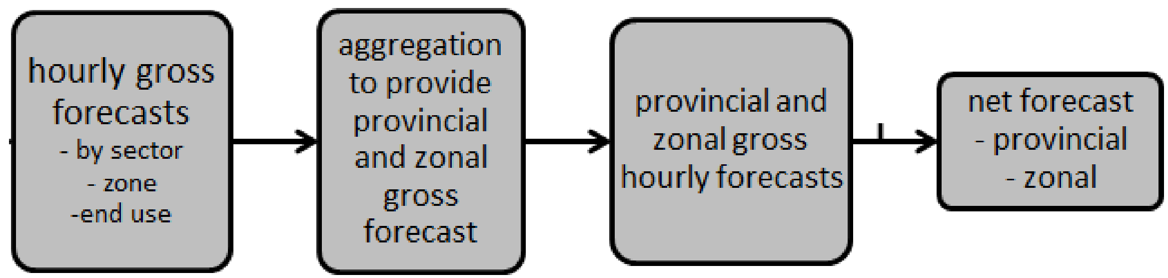
* Others = Agriculture, Remote communities, Generator Demand, IEI and Street Lighting

How we develop long term load forecast

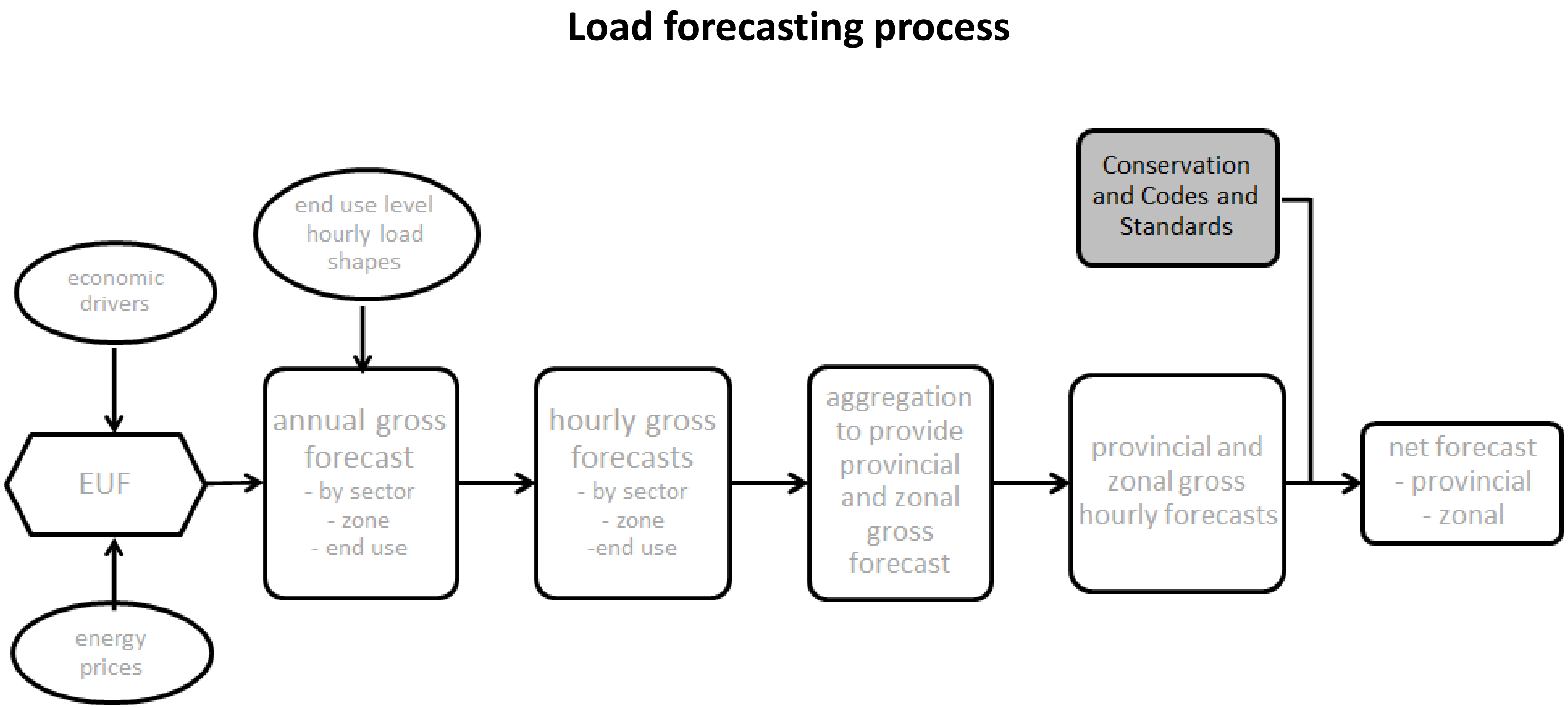


How we develop the long-term load forecast

Load forecasting process



How we develop the long-term load forecast



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

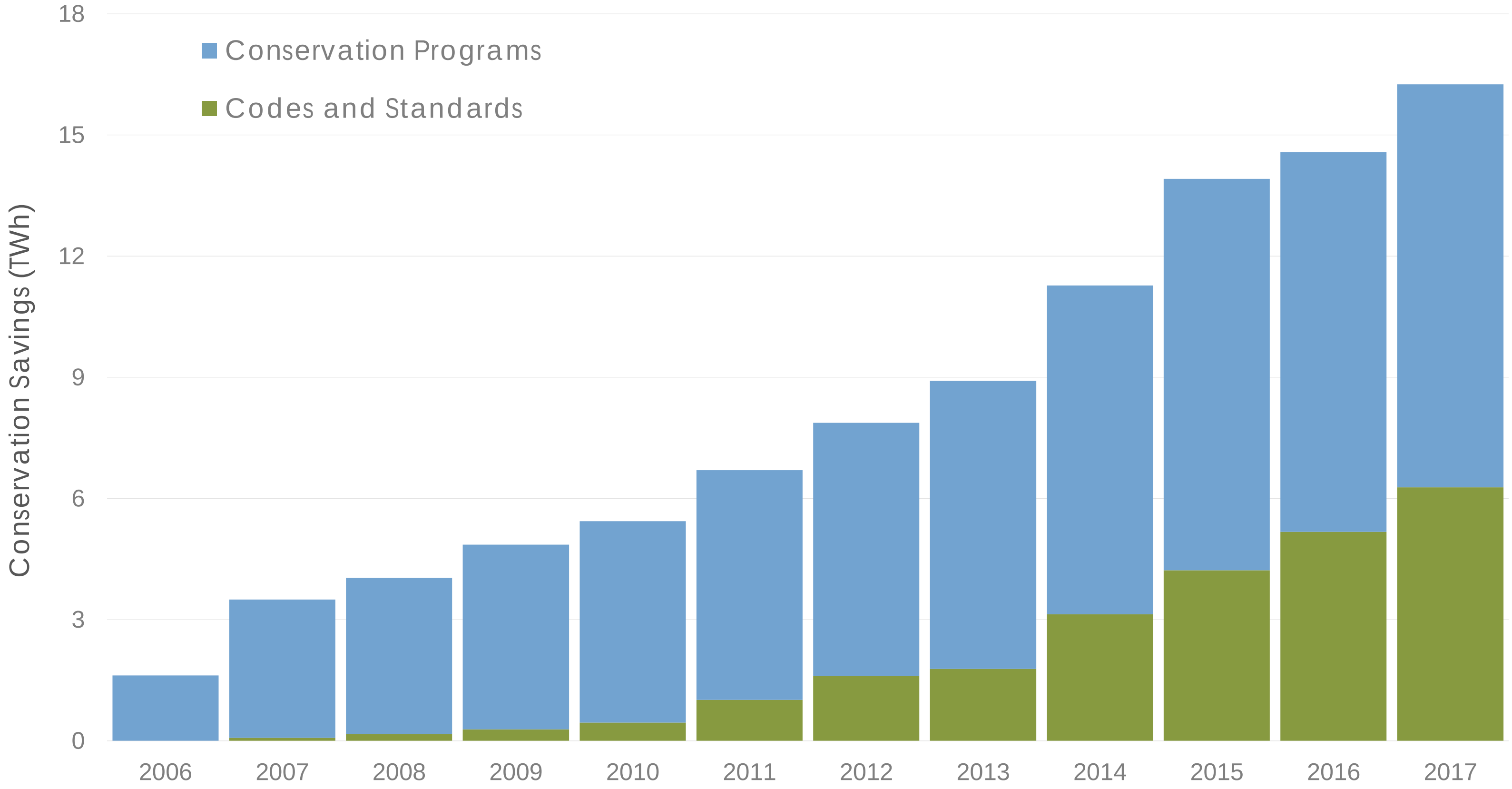
Gross Demand: is the total demand for electricity services in Ontario prior to the impact of conservation programs

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



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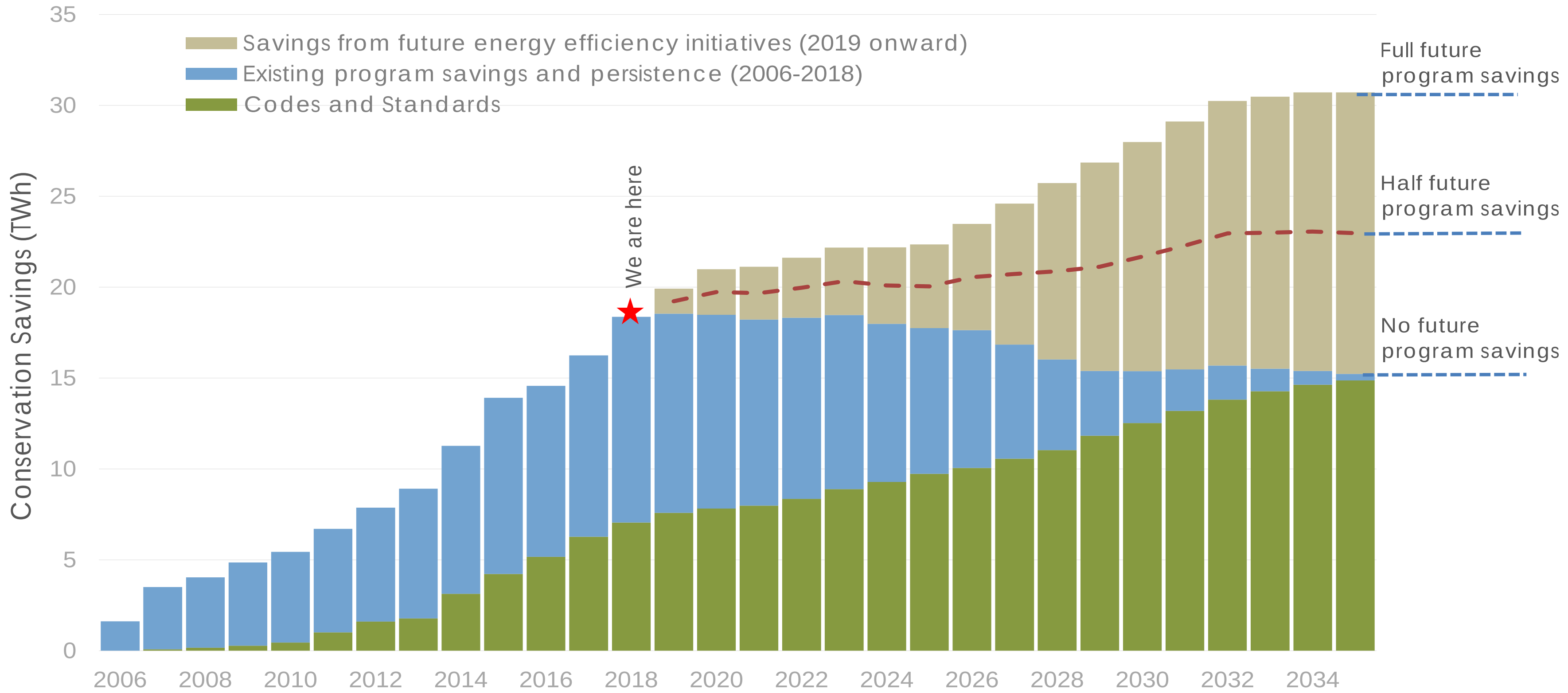
Long-term conservation forecast of 32 TWh by 2035

- 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.



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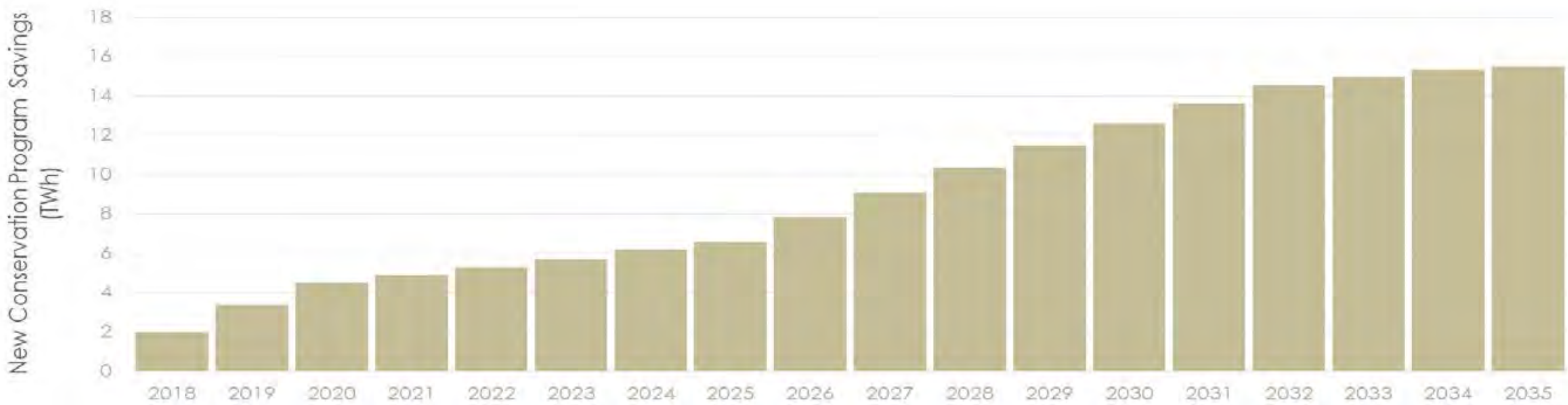
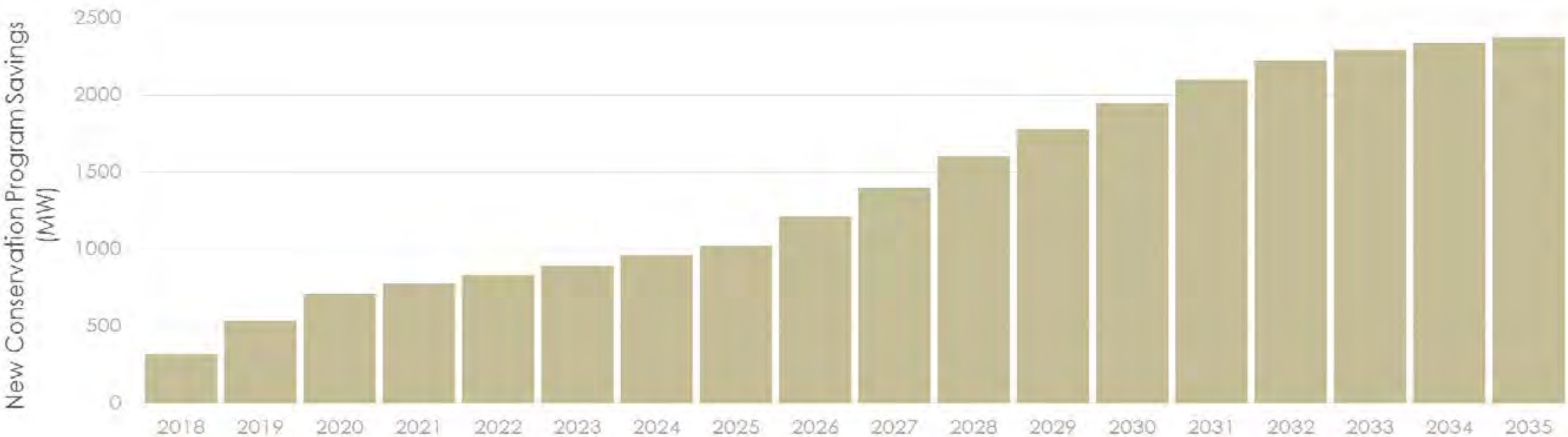
Long-term conservation forecast

- 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.





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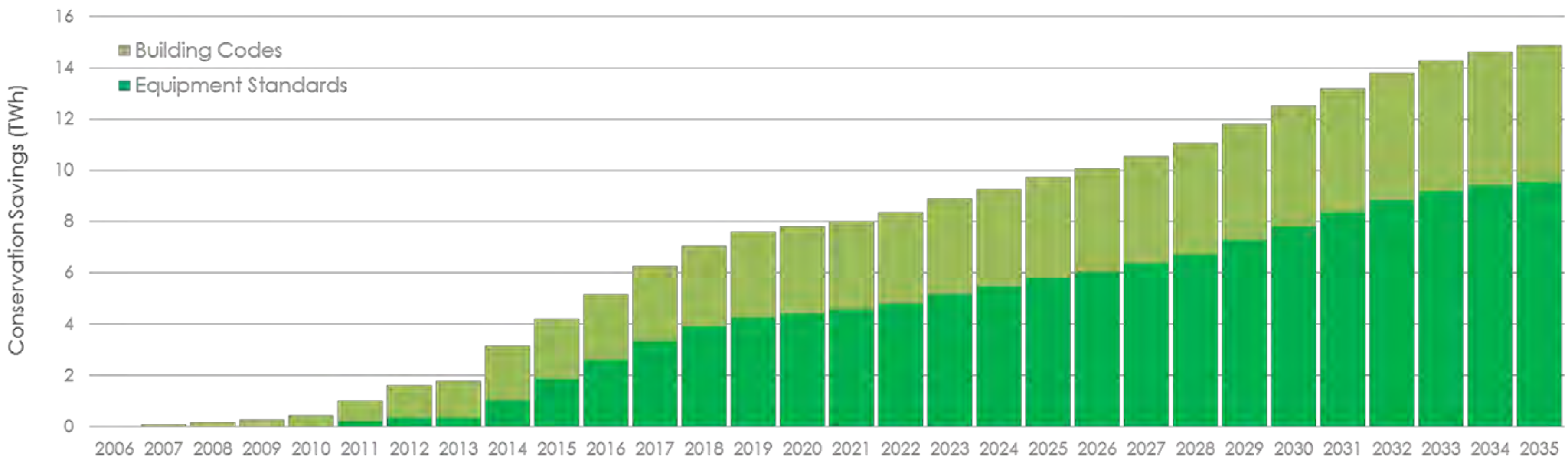
Factoring in codes and standards



- 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.

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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

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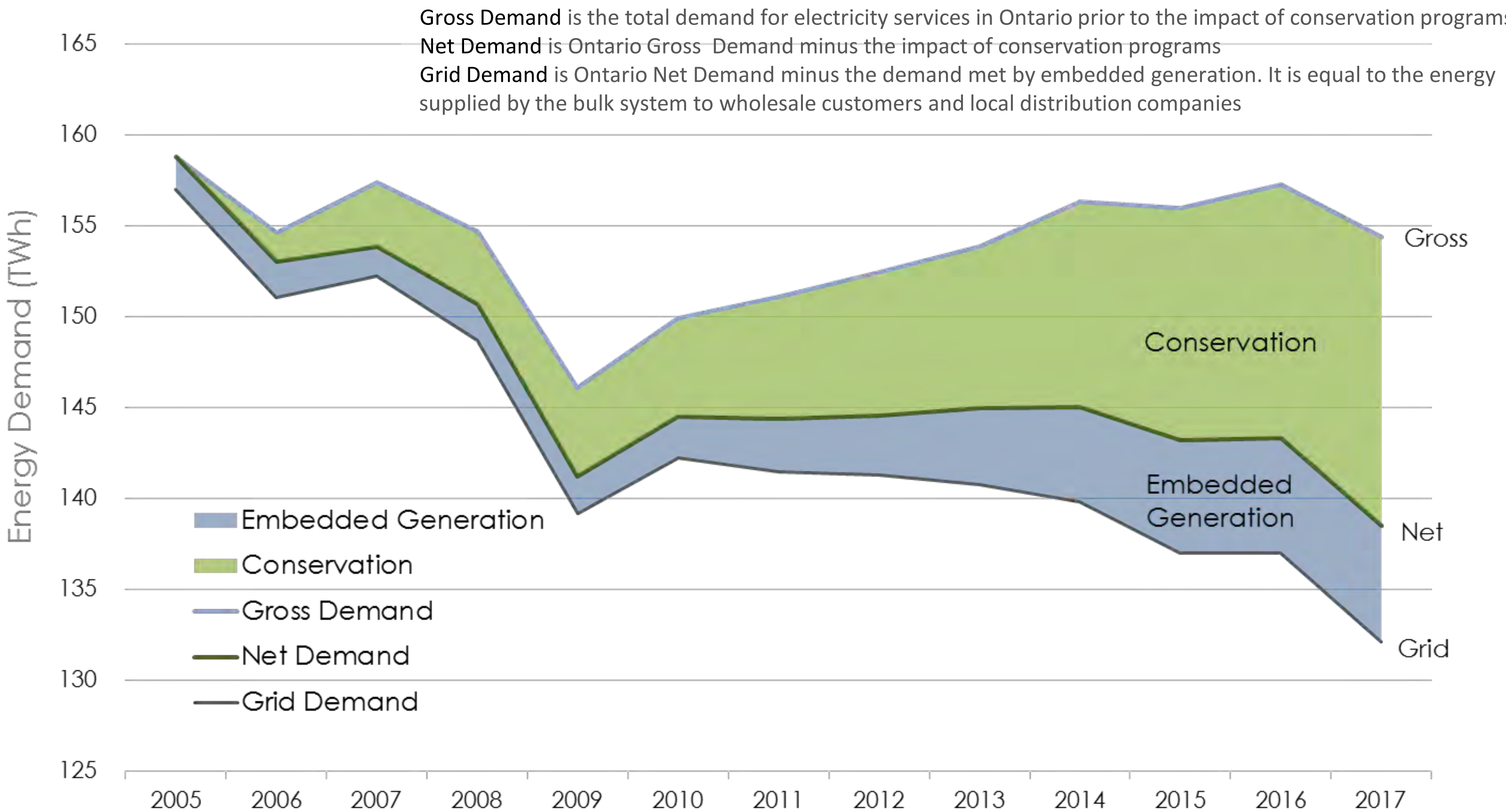
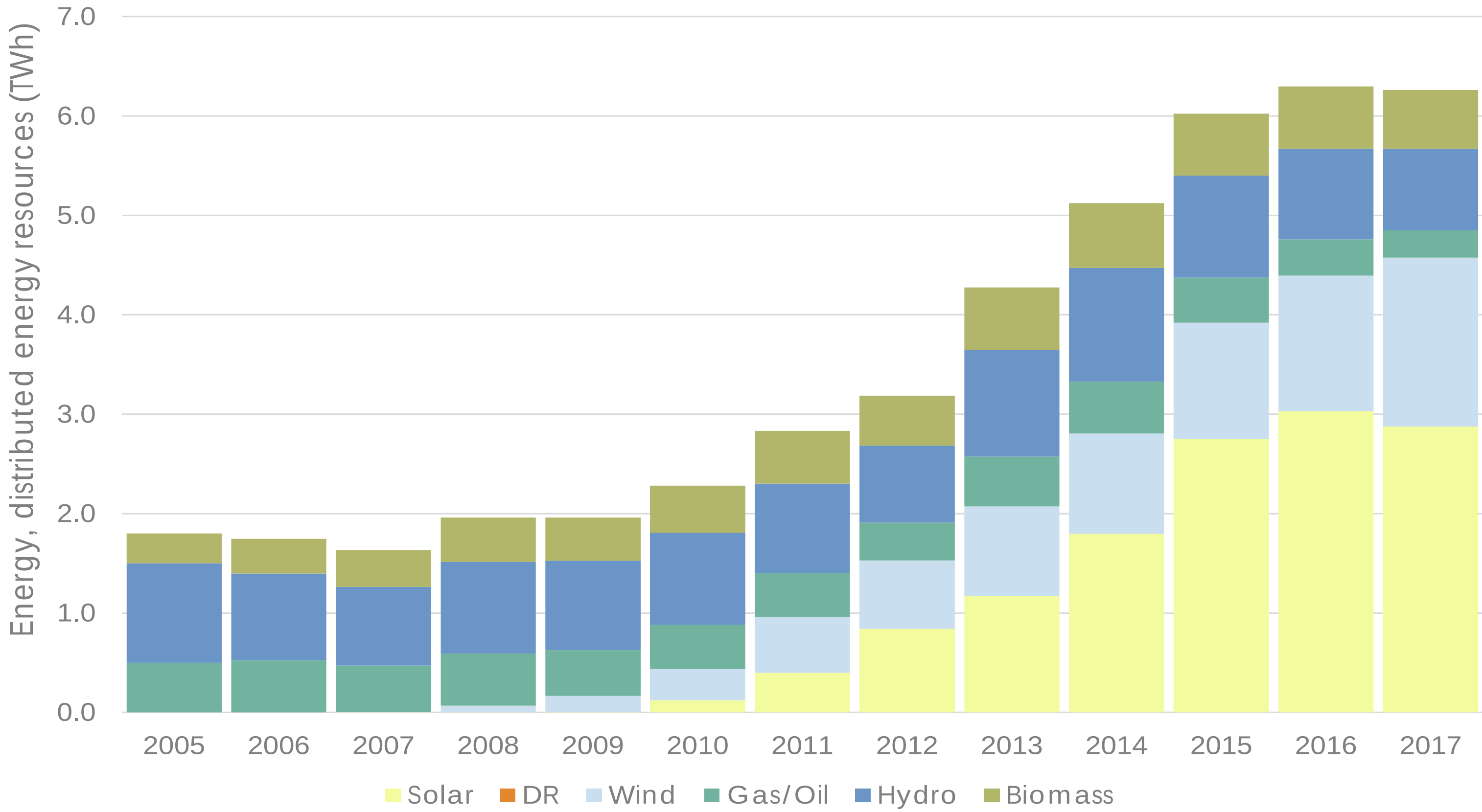
Historical demand: 2005 – 2017

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



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.

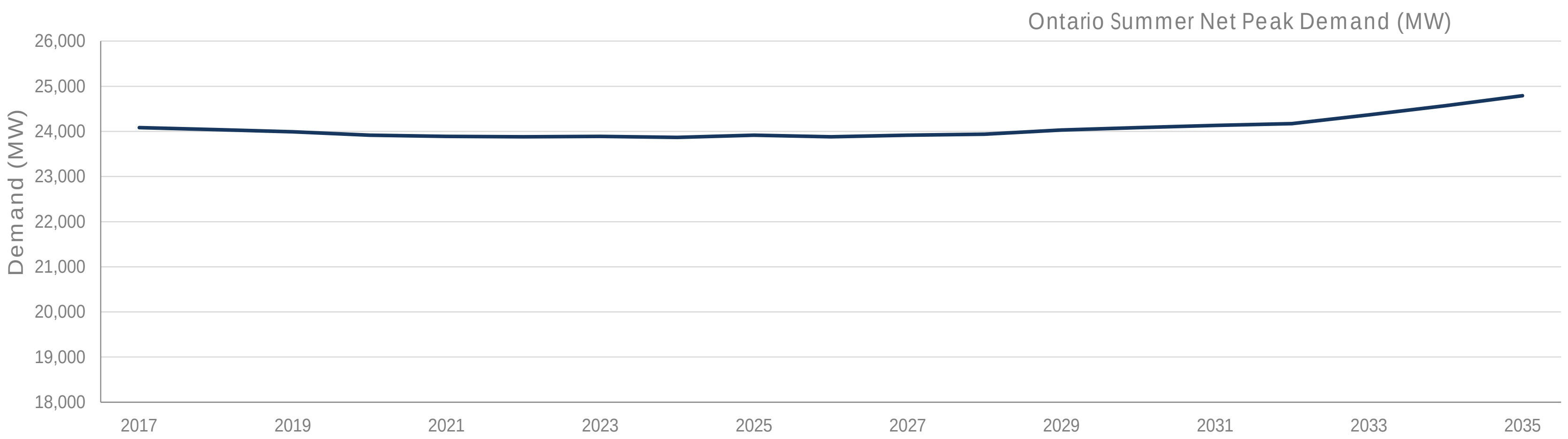


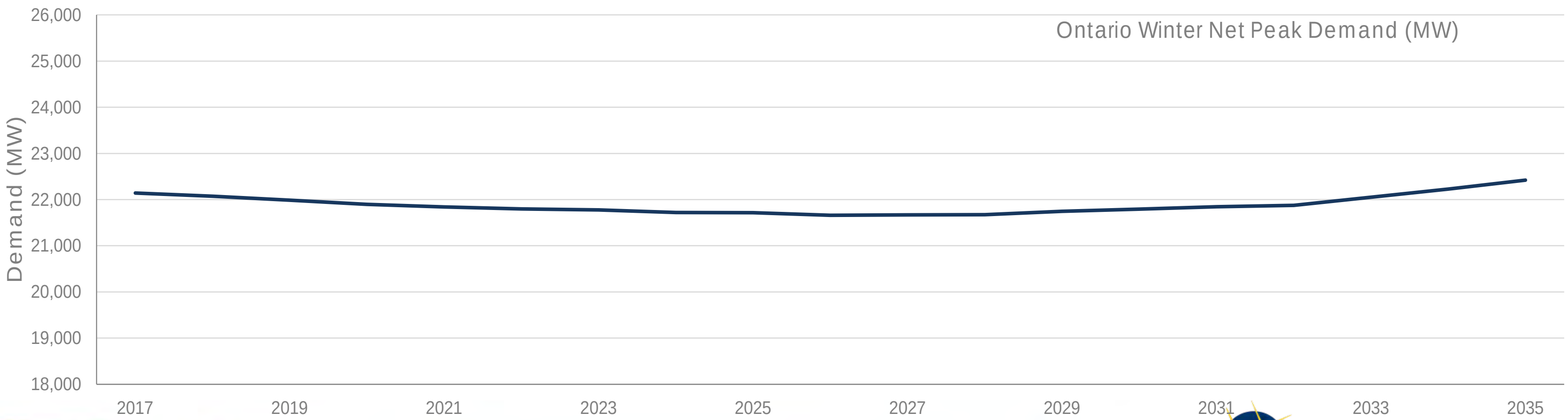
Energy demand by sector: Scenario/Outlooks, with key assumptions

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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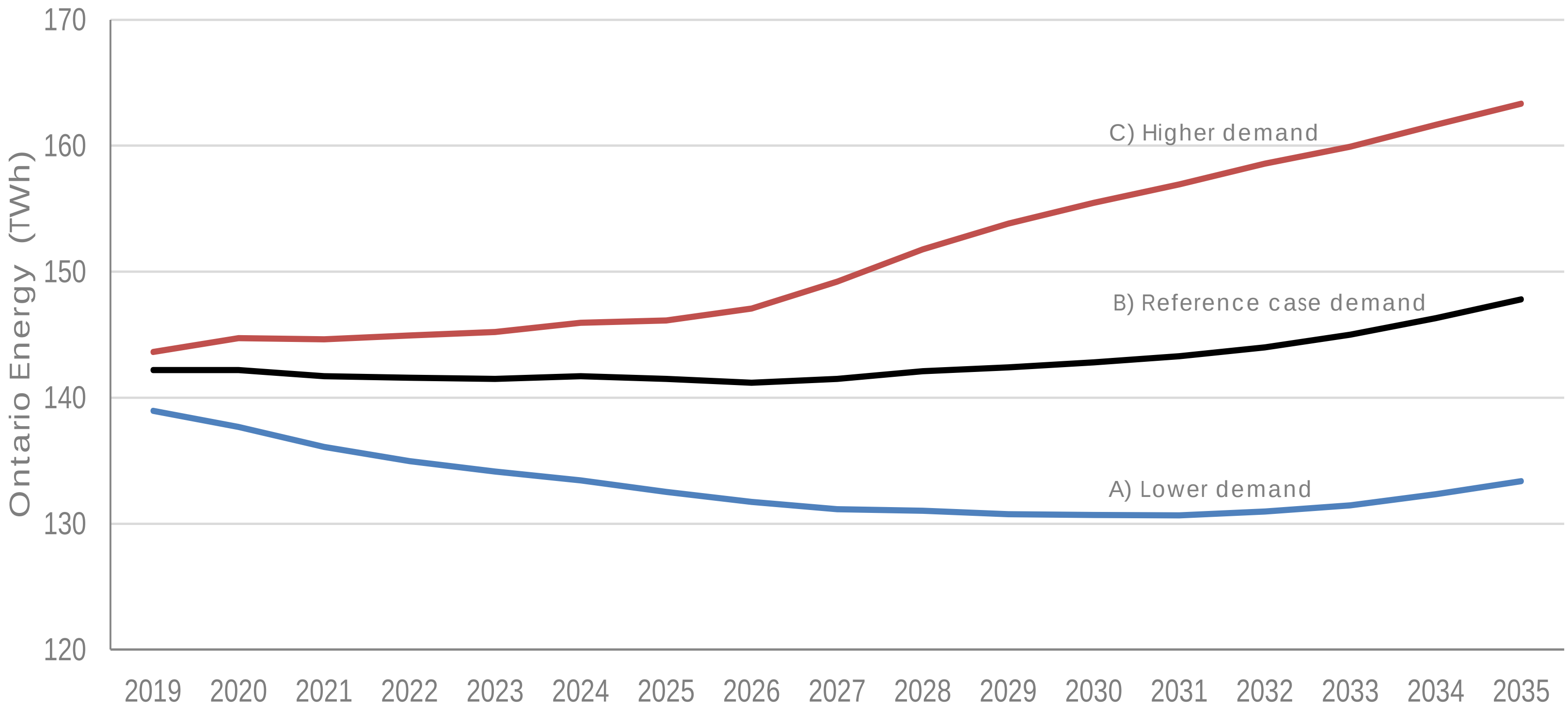
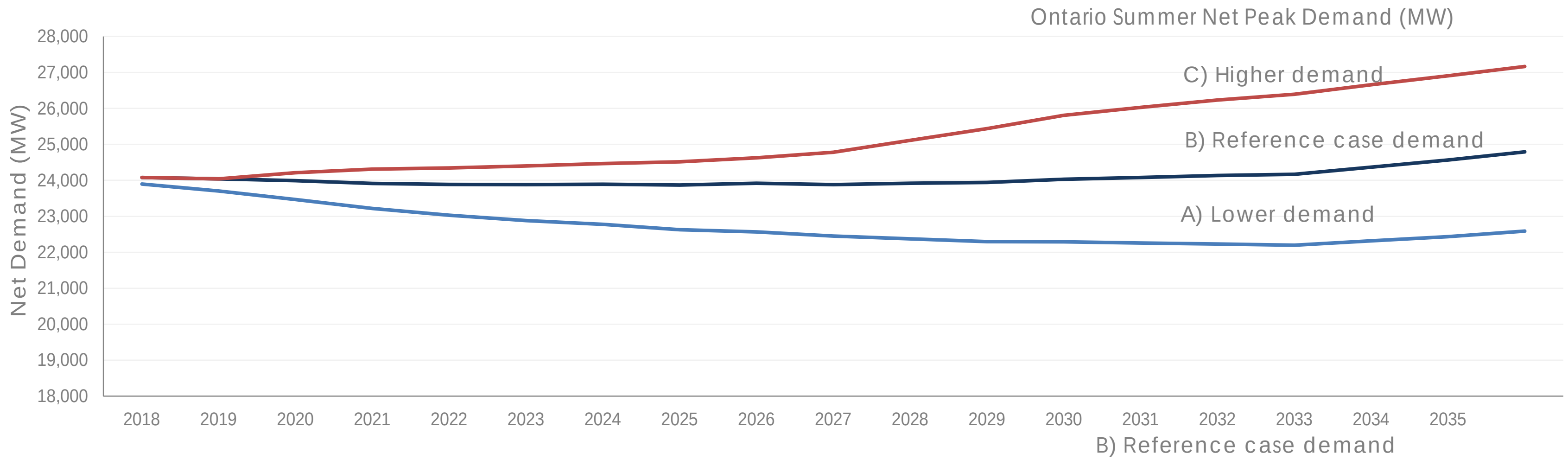
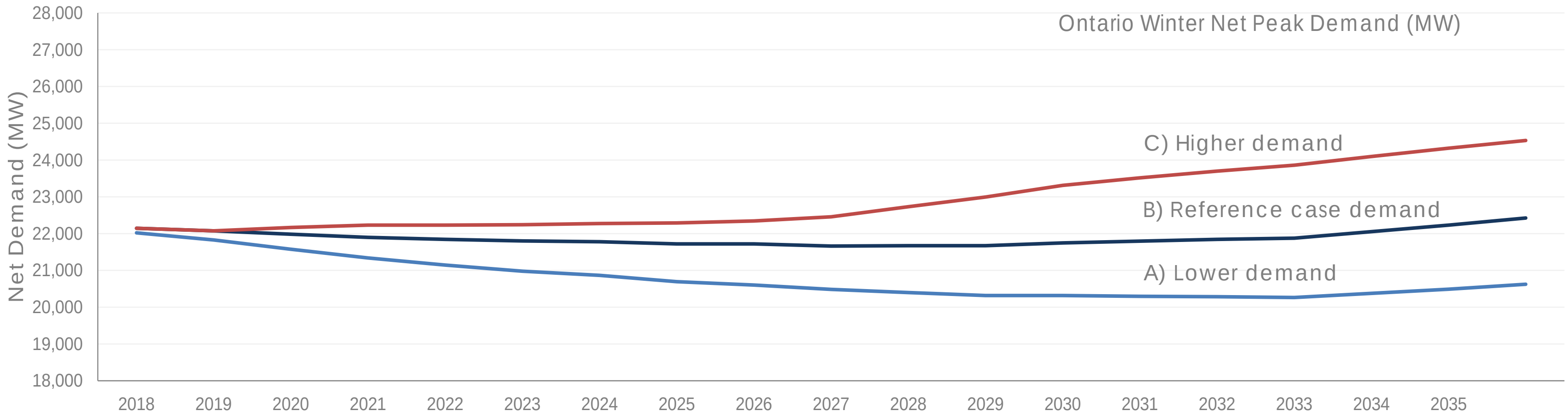
Demand outlooks: Energy demand

- 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.

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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*

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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

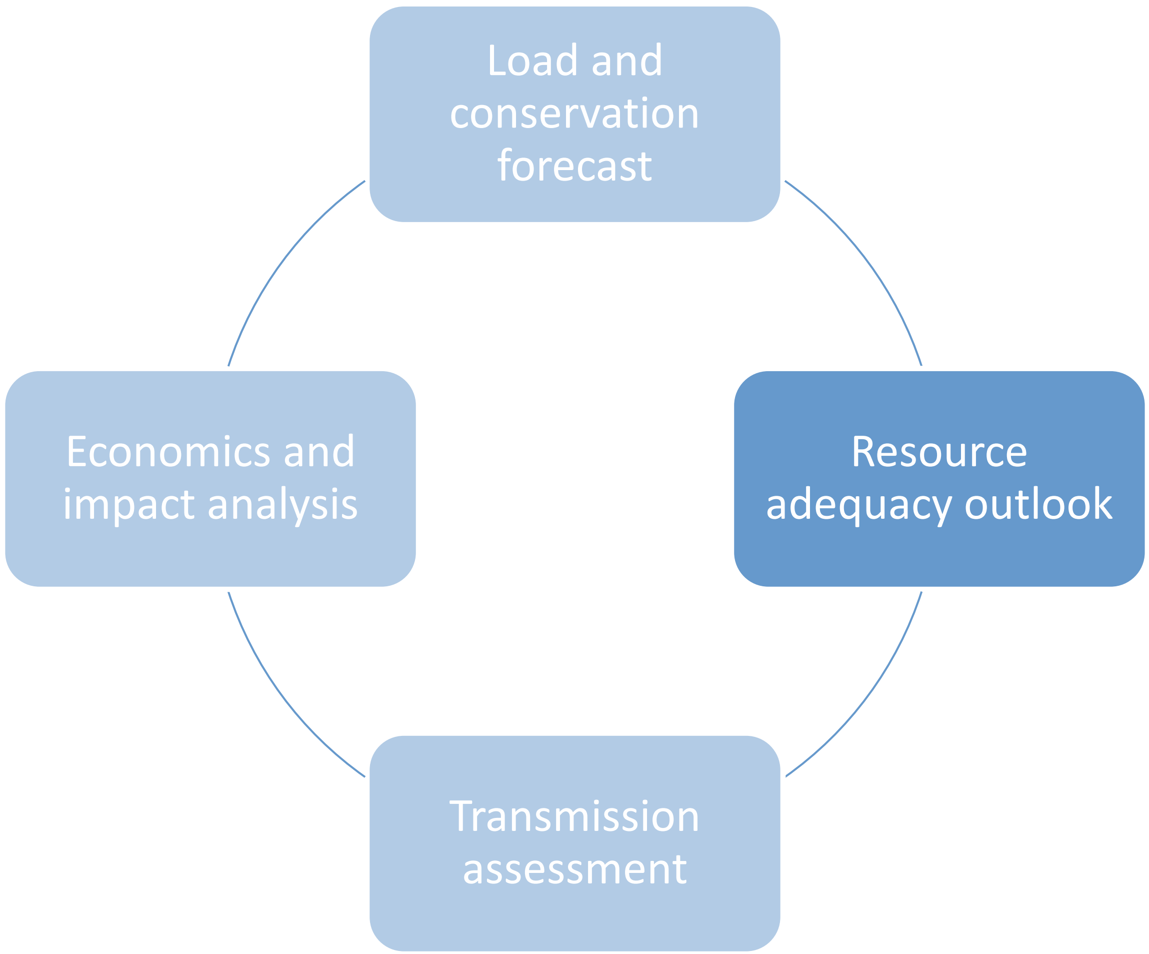
- Scenarios need to be developed to address the risk of change in demand and to provide more context for planning. Factors to consider include:

  - ✓ 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

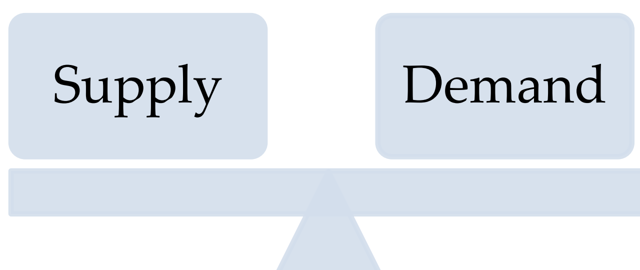


What is resource adequacy?

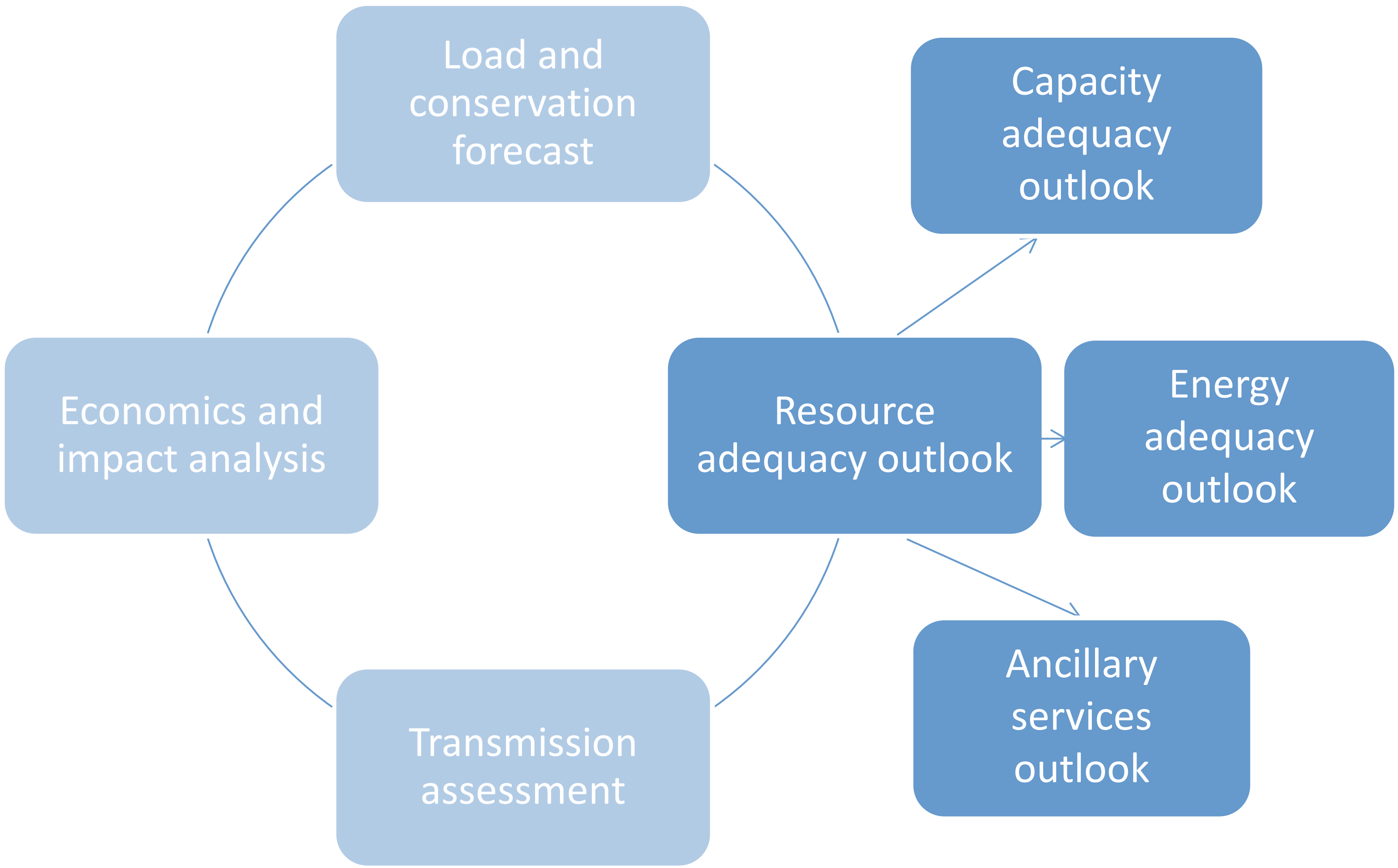
- Adequacy assessments are a way to assess the ability of electricity resources to meet electricity demand at all times, taking into consideration the demand forecast, generator availability, and transmission constraints.

- 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



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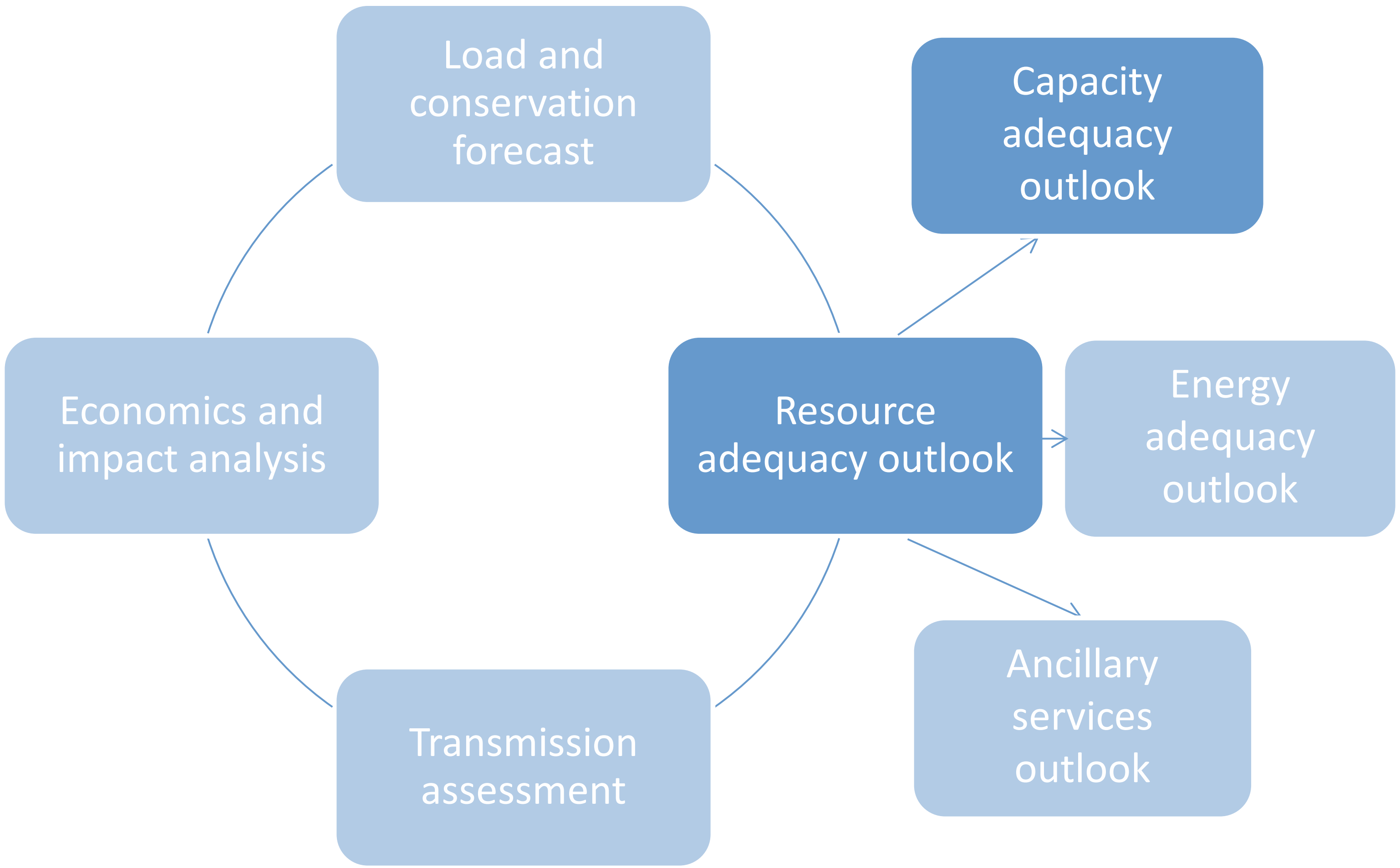
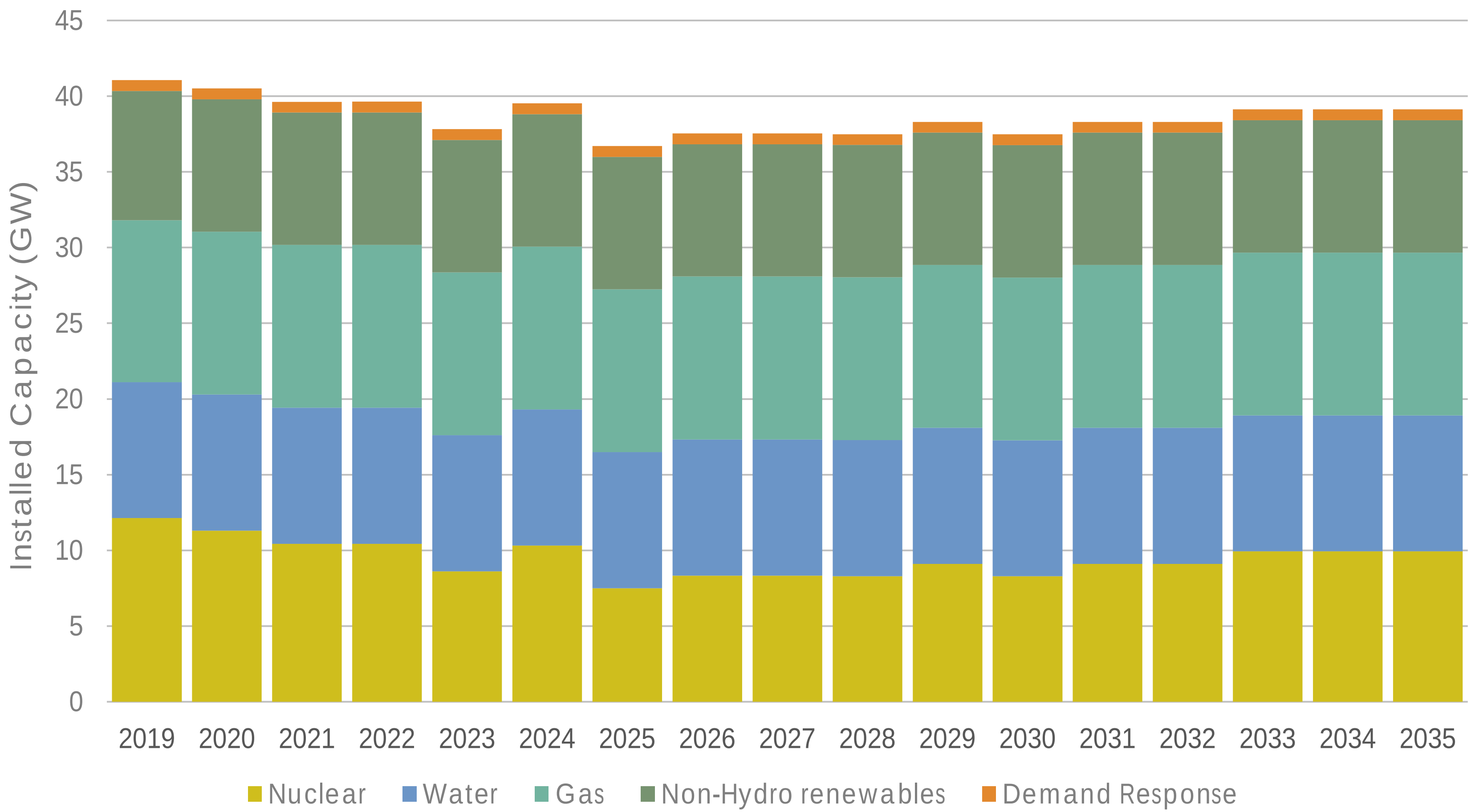
Capacity Adequacy Outlook



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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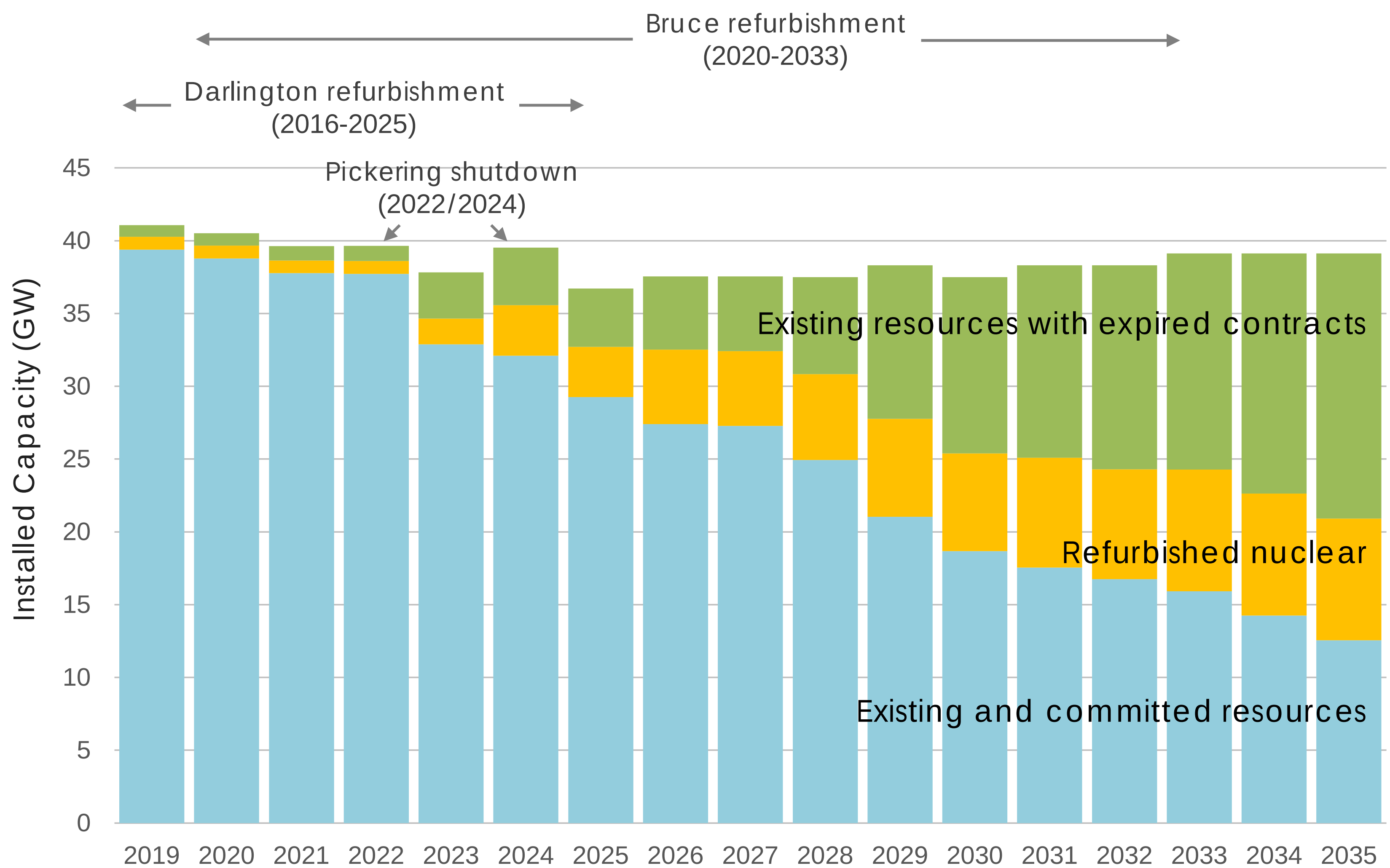
Outlook for supply resources

- 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

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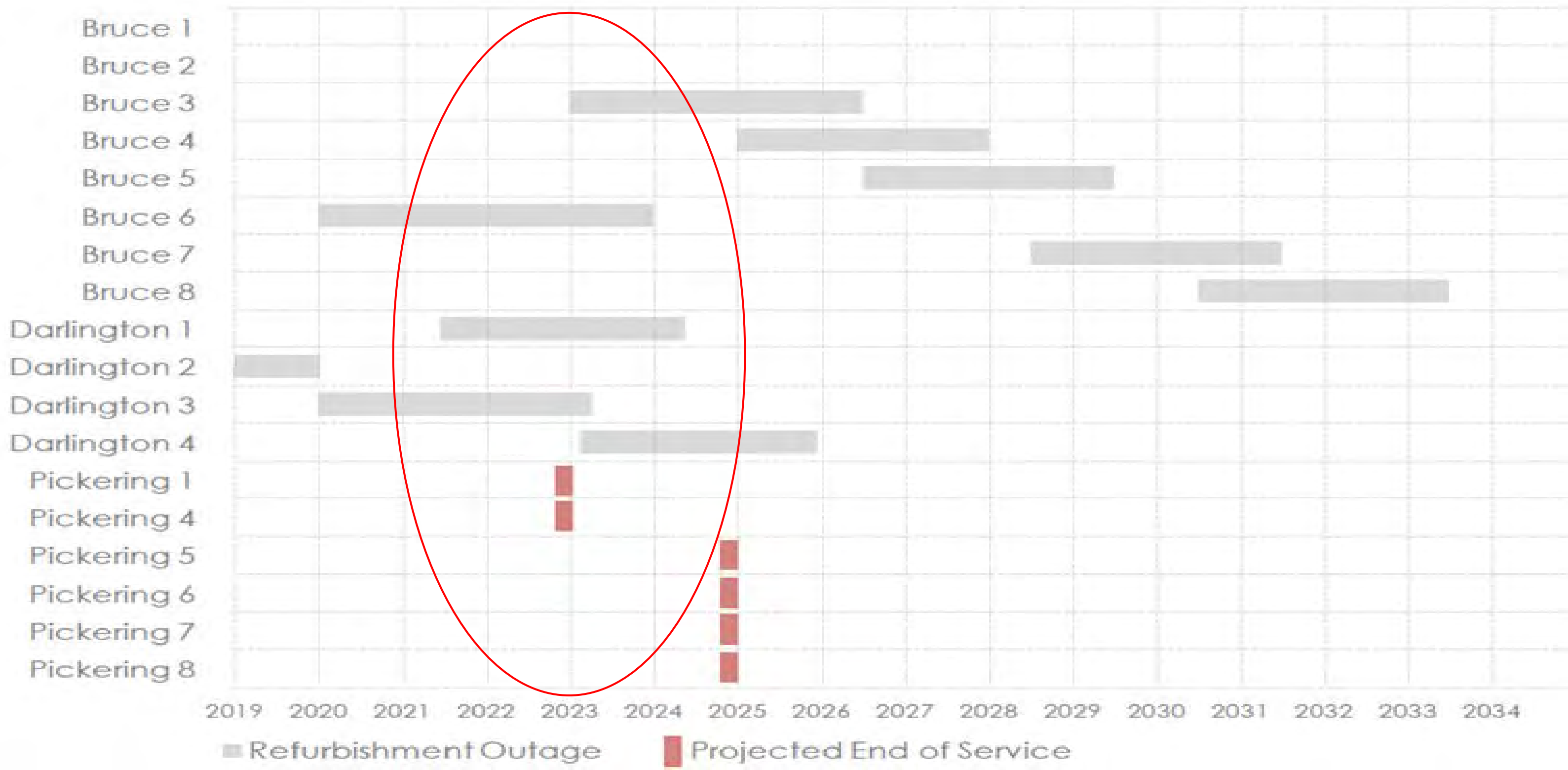
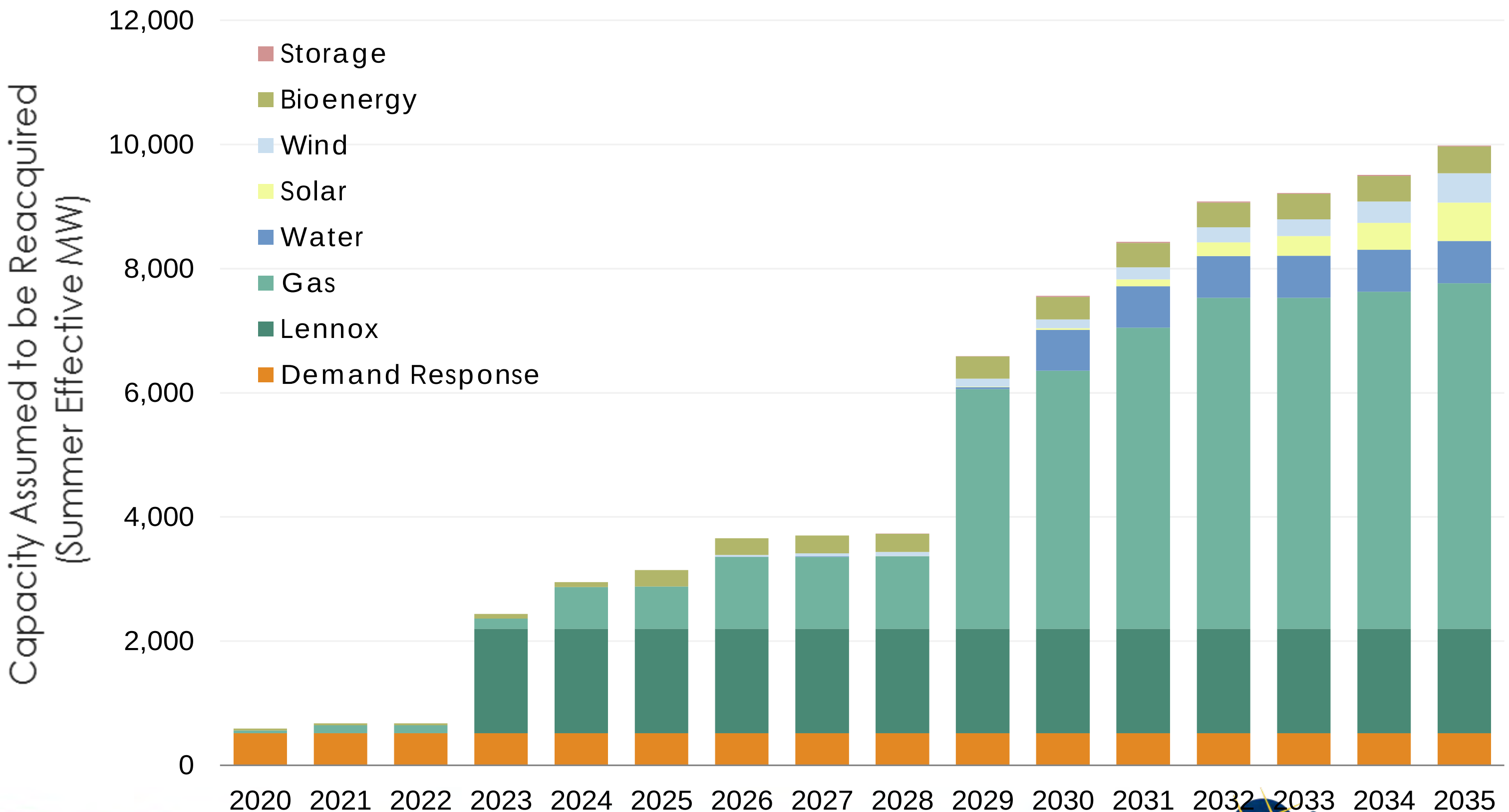
Nuclear refurbishment and retirement schedule

- 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.



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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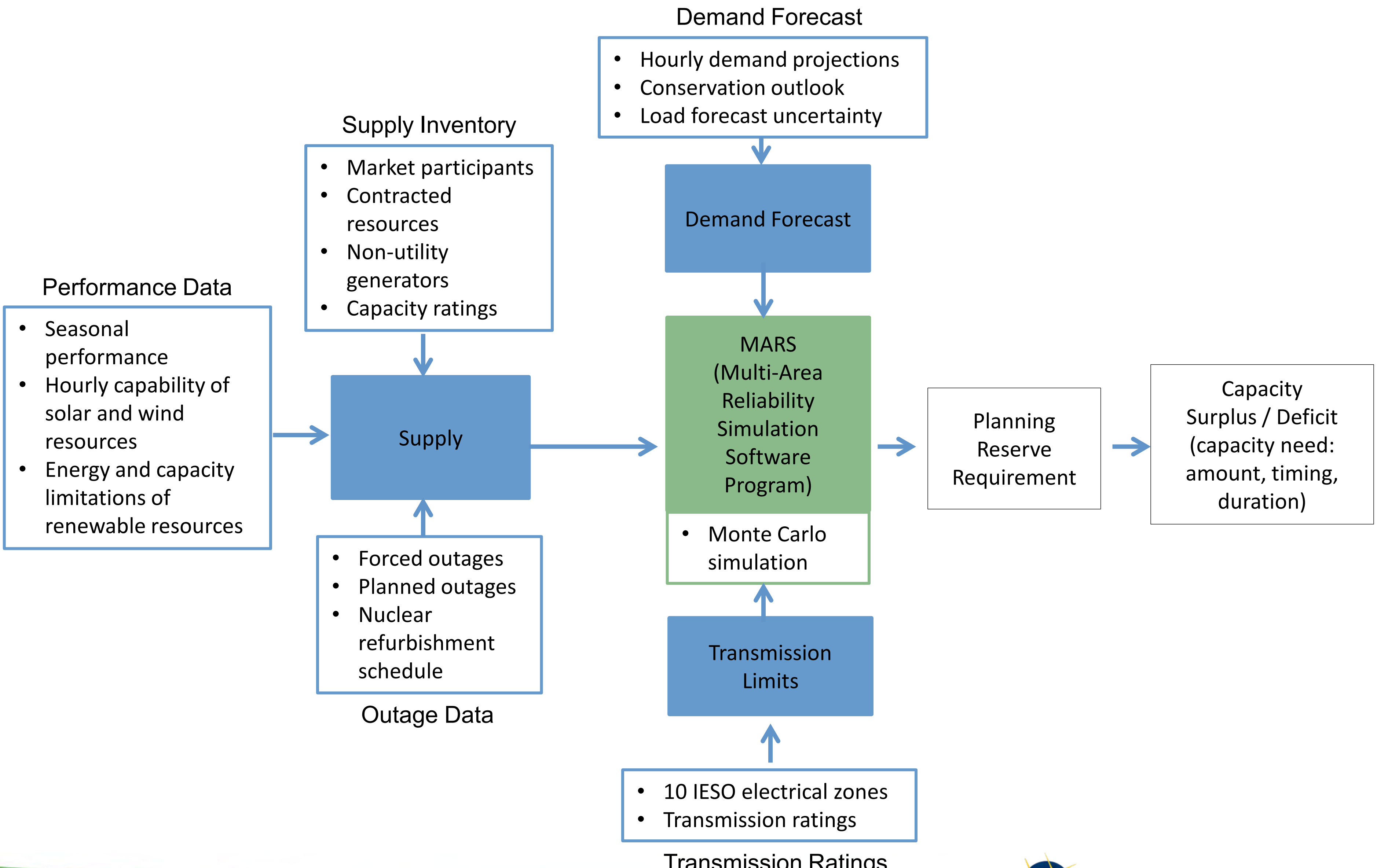
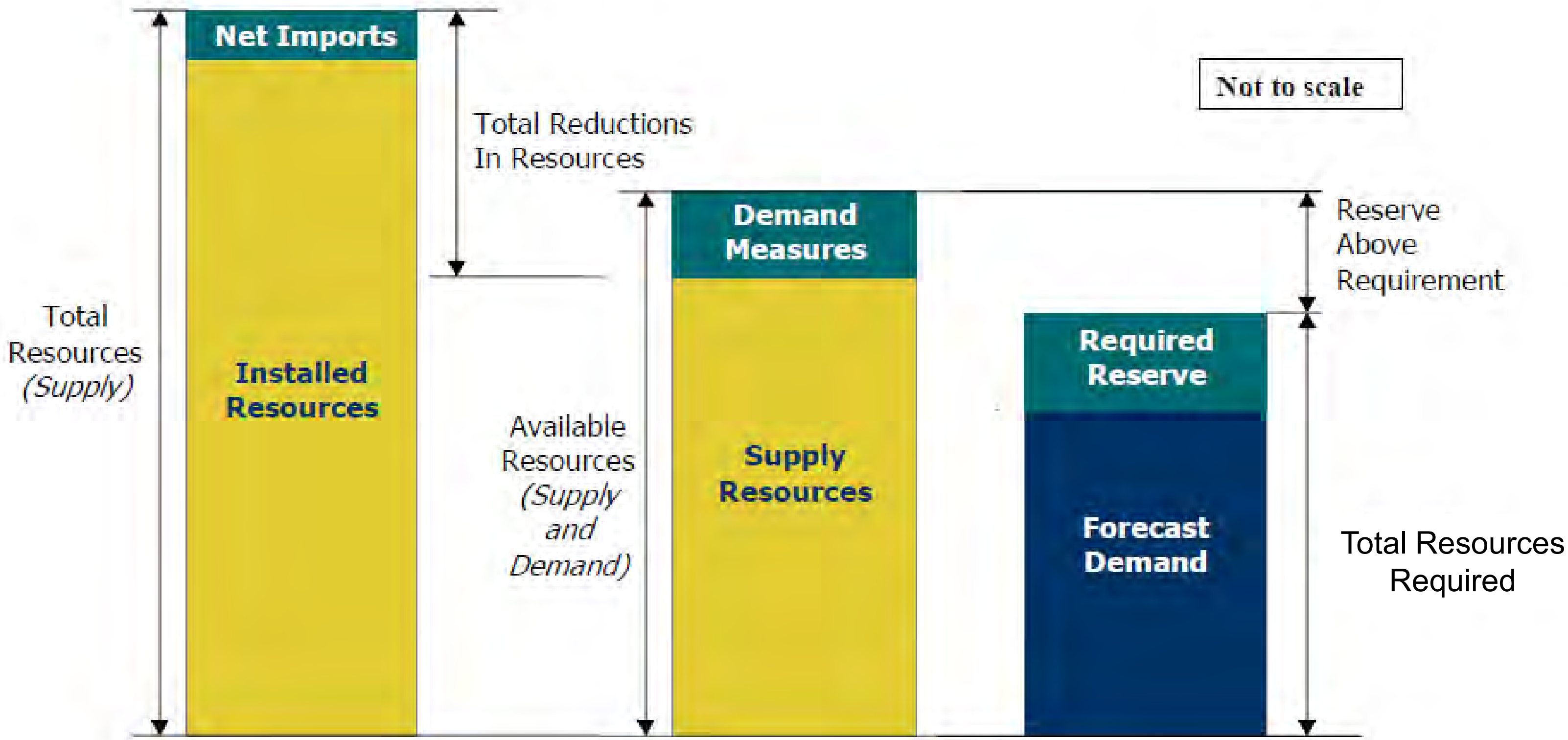
Resource adequacy assessment process



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).

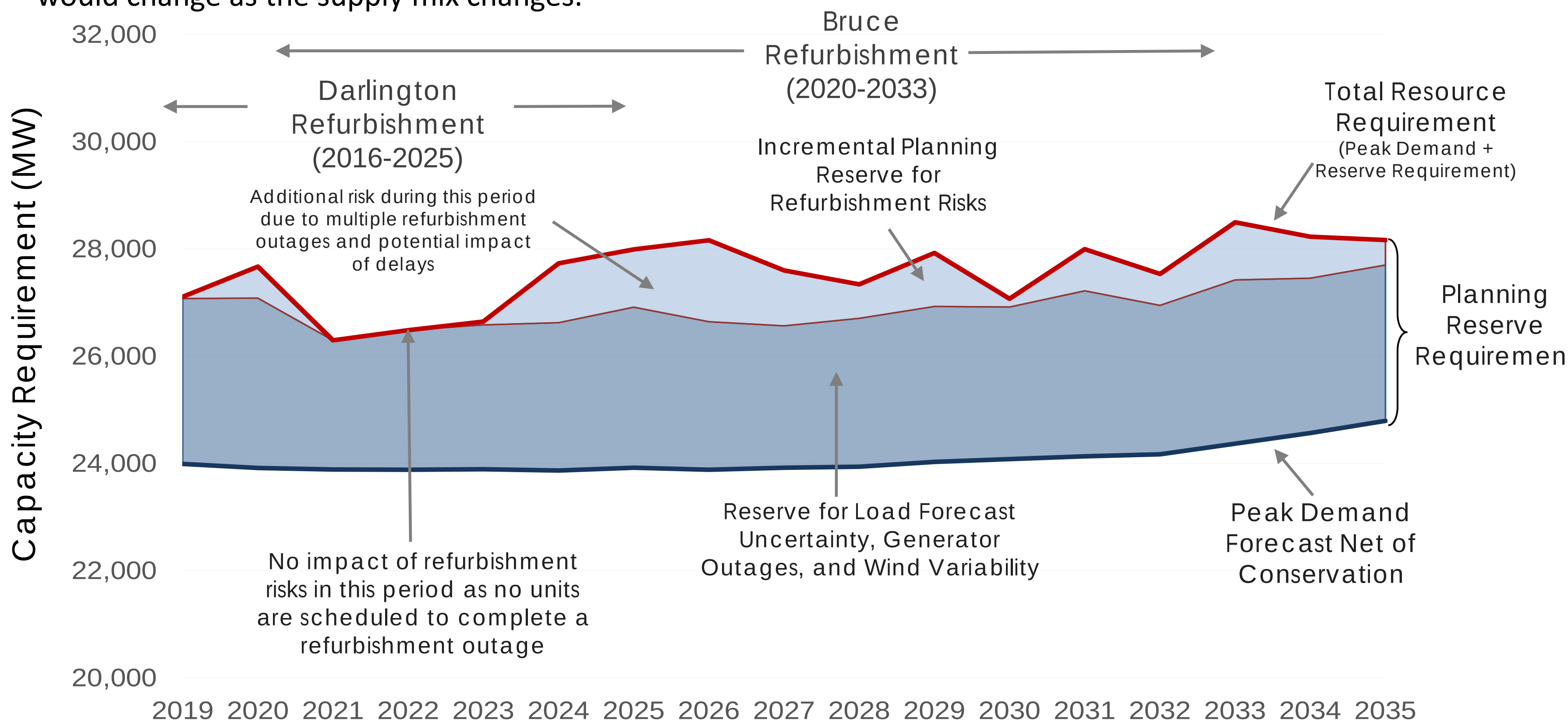
Reserve assessment – model and key inputs

- 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.

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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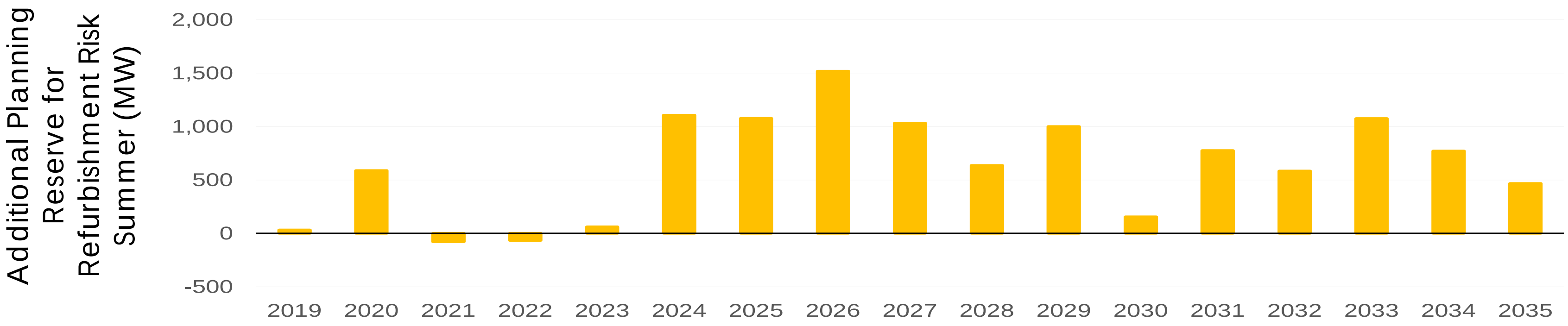
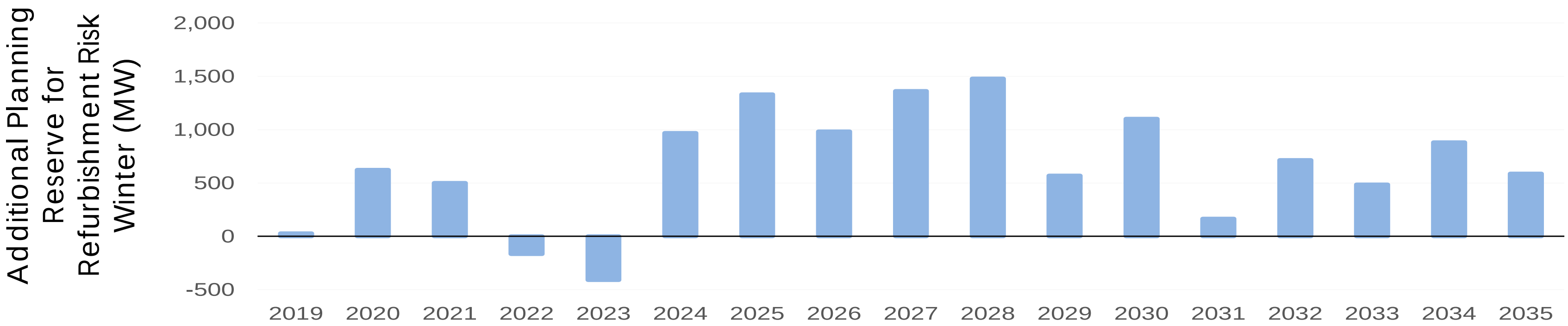
Incremental planning reserve required to cover refurbishment performance risk

- 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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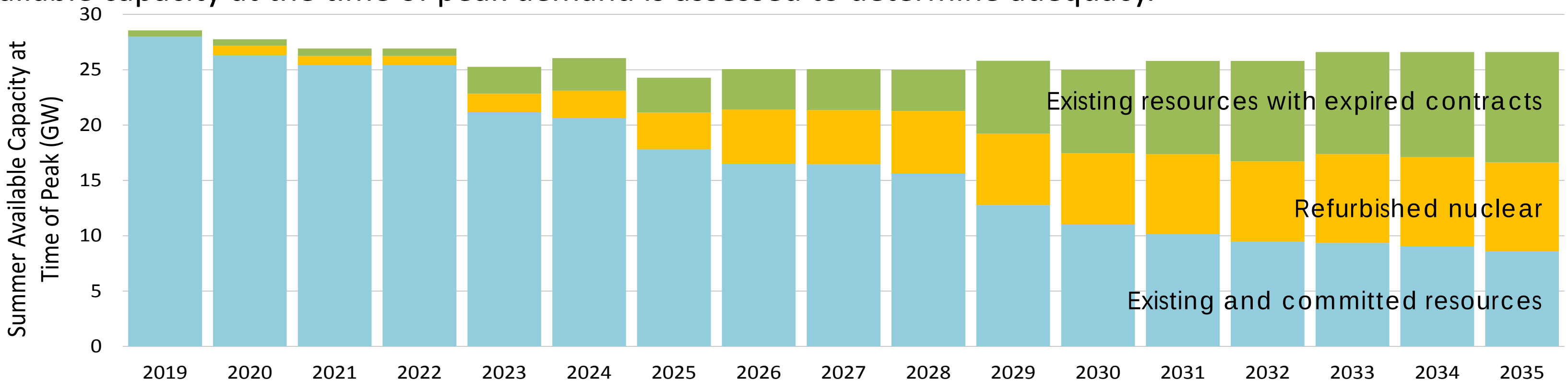
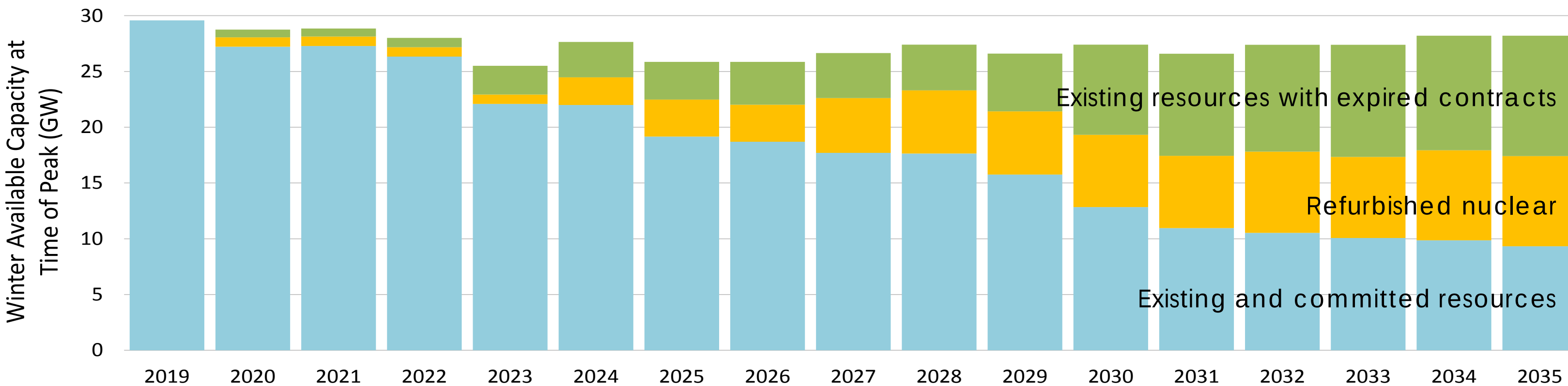
Available capacity at time of peak

- 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.

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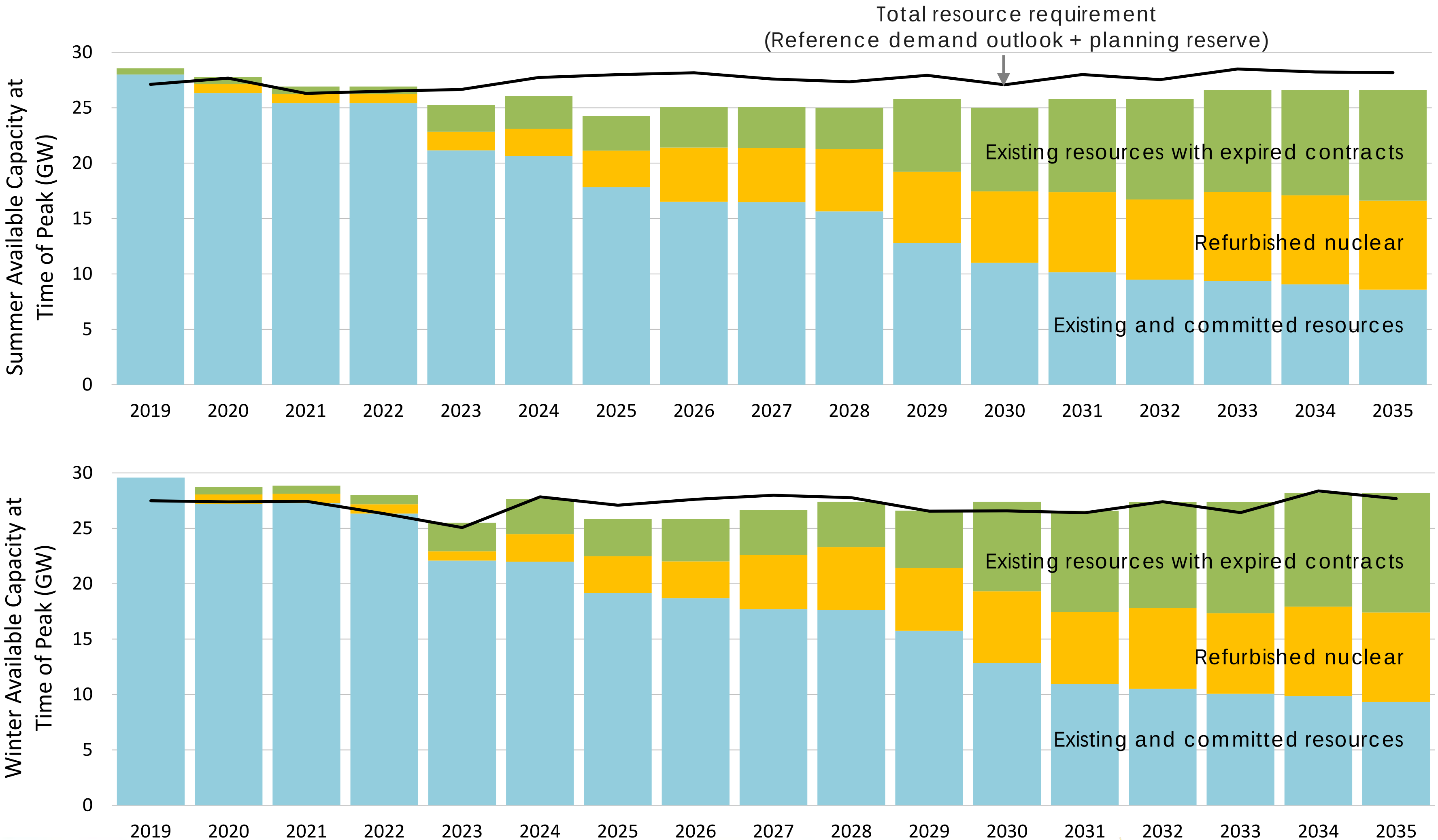
Available capacity compared to the total resource requirement

- 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).



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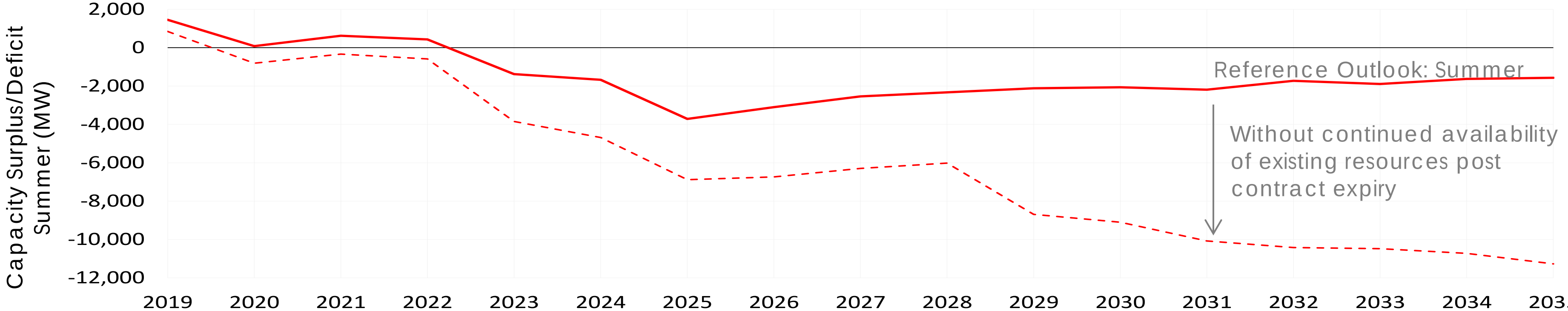
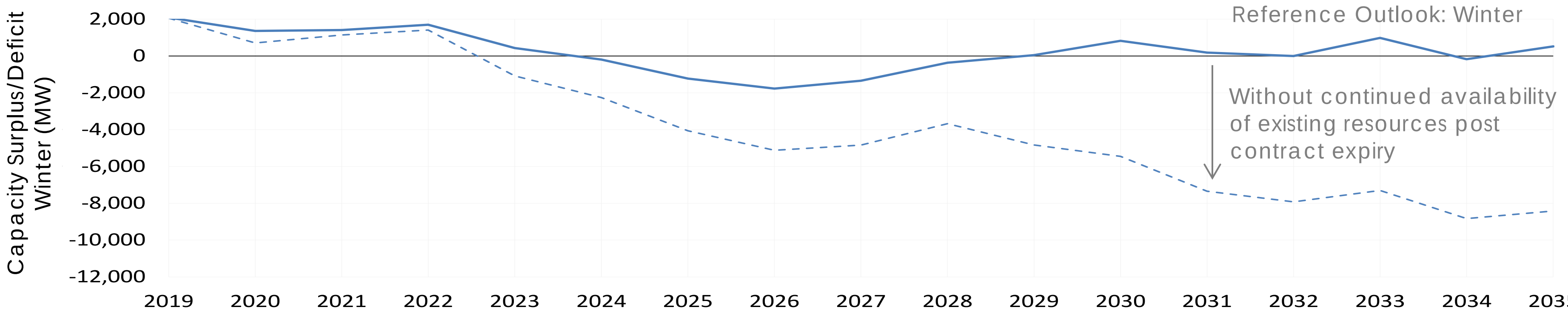
Capacity adequacy outlook (surplus/deficit): Reference demand outlook, with continued availability of existing resources with expiring contracts

- 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

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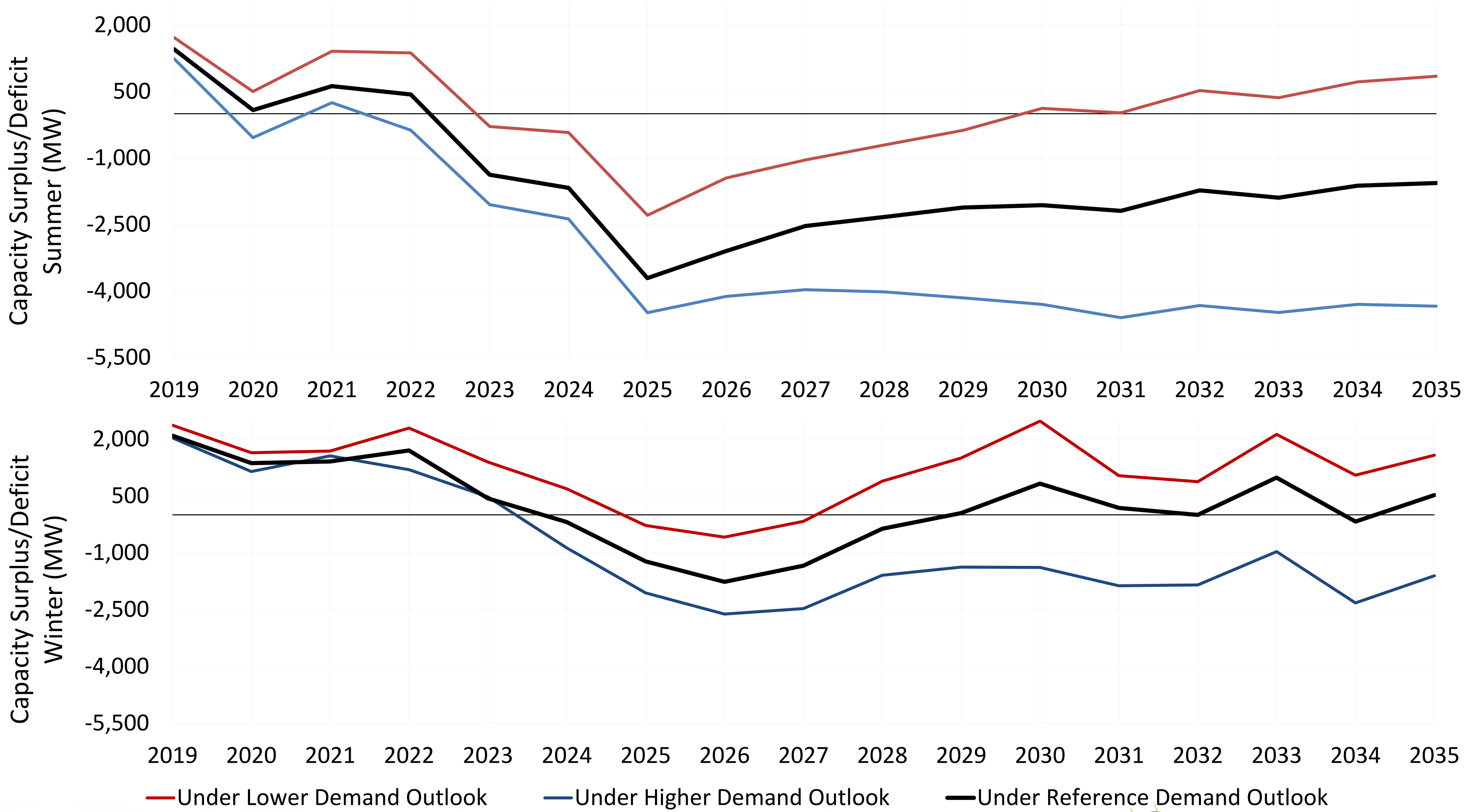
Capacity adequacy outlook (surplus/deficit): Across demand outlook scenarios, with continued availability of existing resources with expiring contracts

- 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.

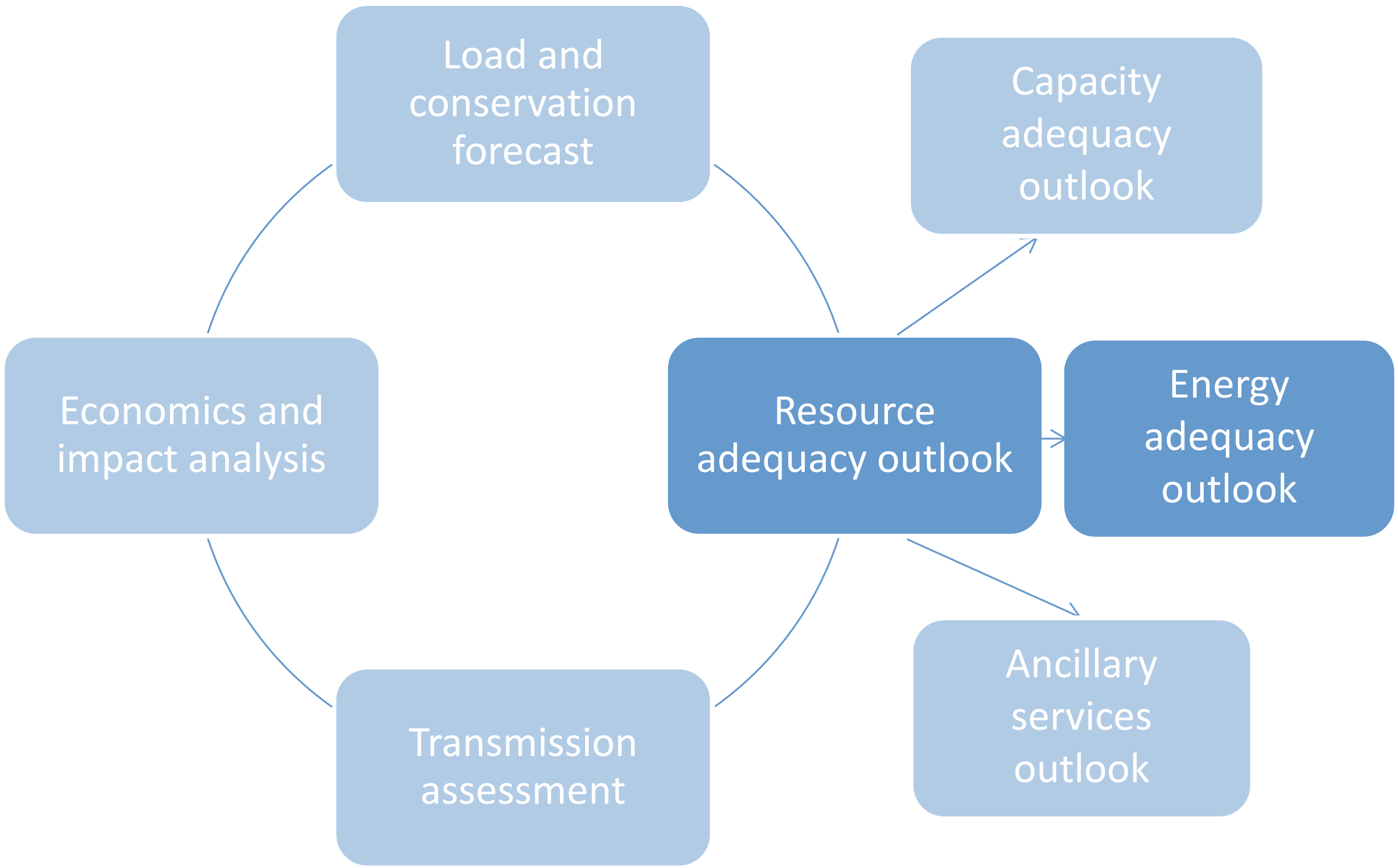
- Many North American jurisdictions (PJM, MISO, NYISO, ISO-NE, etc.) rely on non-firm imports for capacity to contribute towards meeting their capacity adequacy requirements.
  - Supported by NPCC interconnection assistance reports in the near-term.
  - At various times, NERC has raised concern about 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.

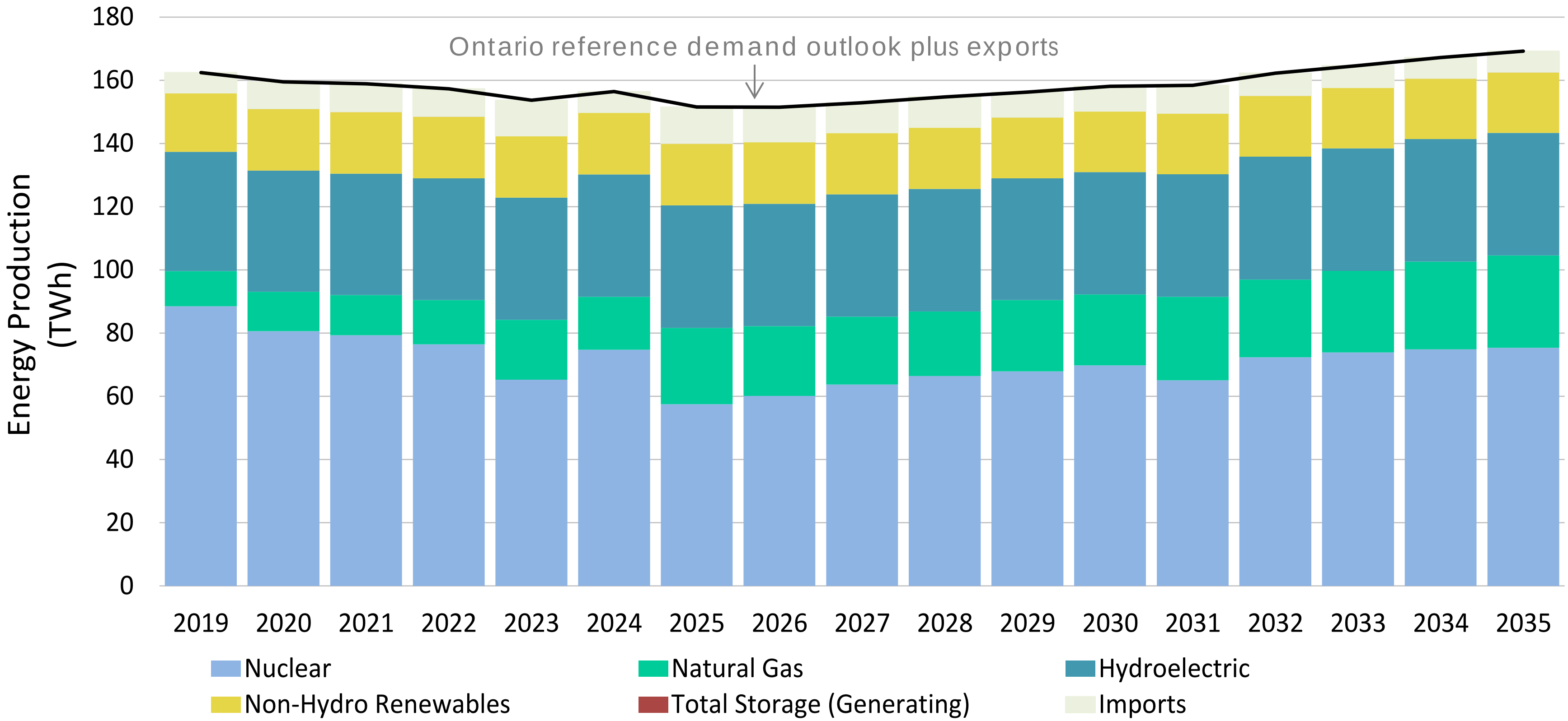
Energy production and economic dispatch assessments

- 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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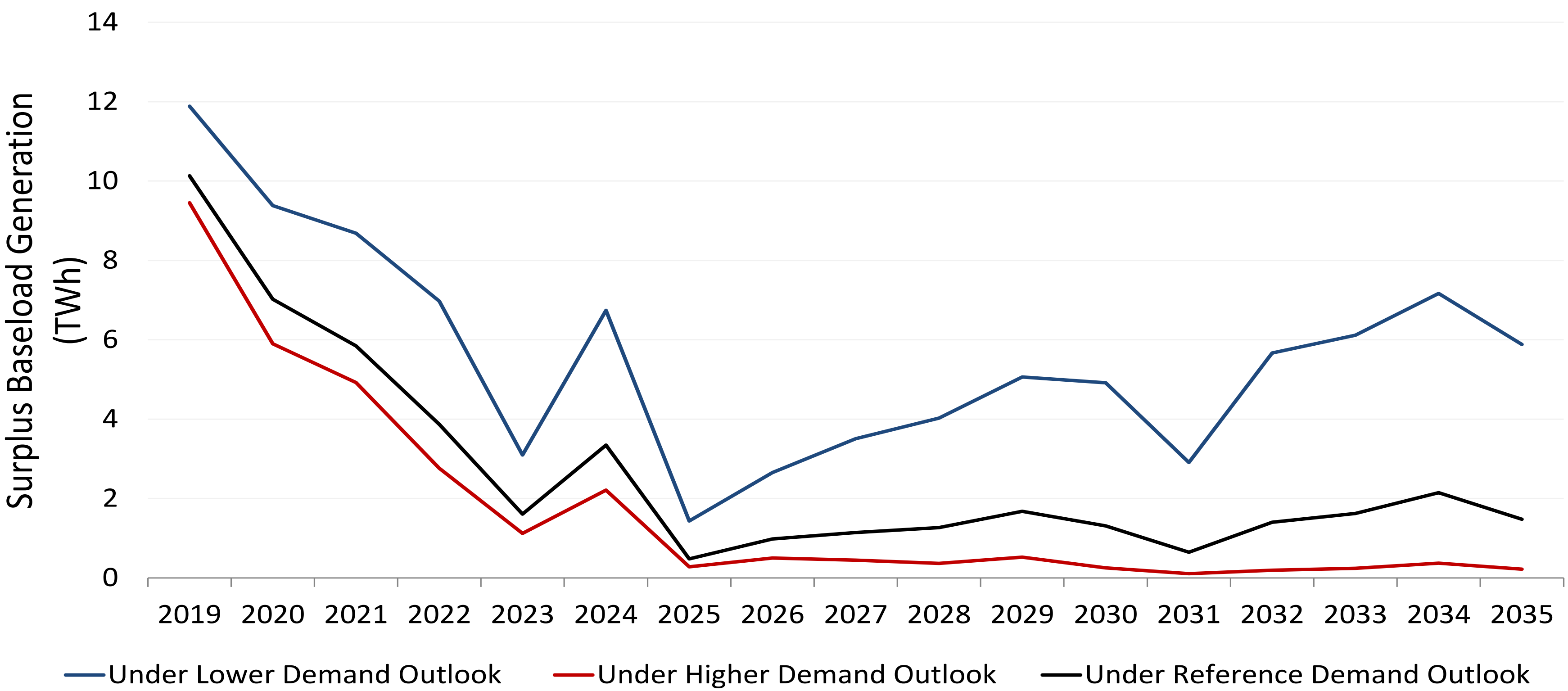
Energy adequacy outlook - key observations

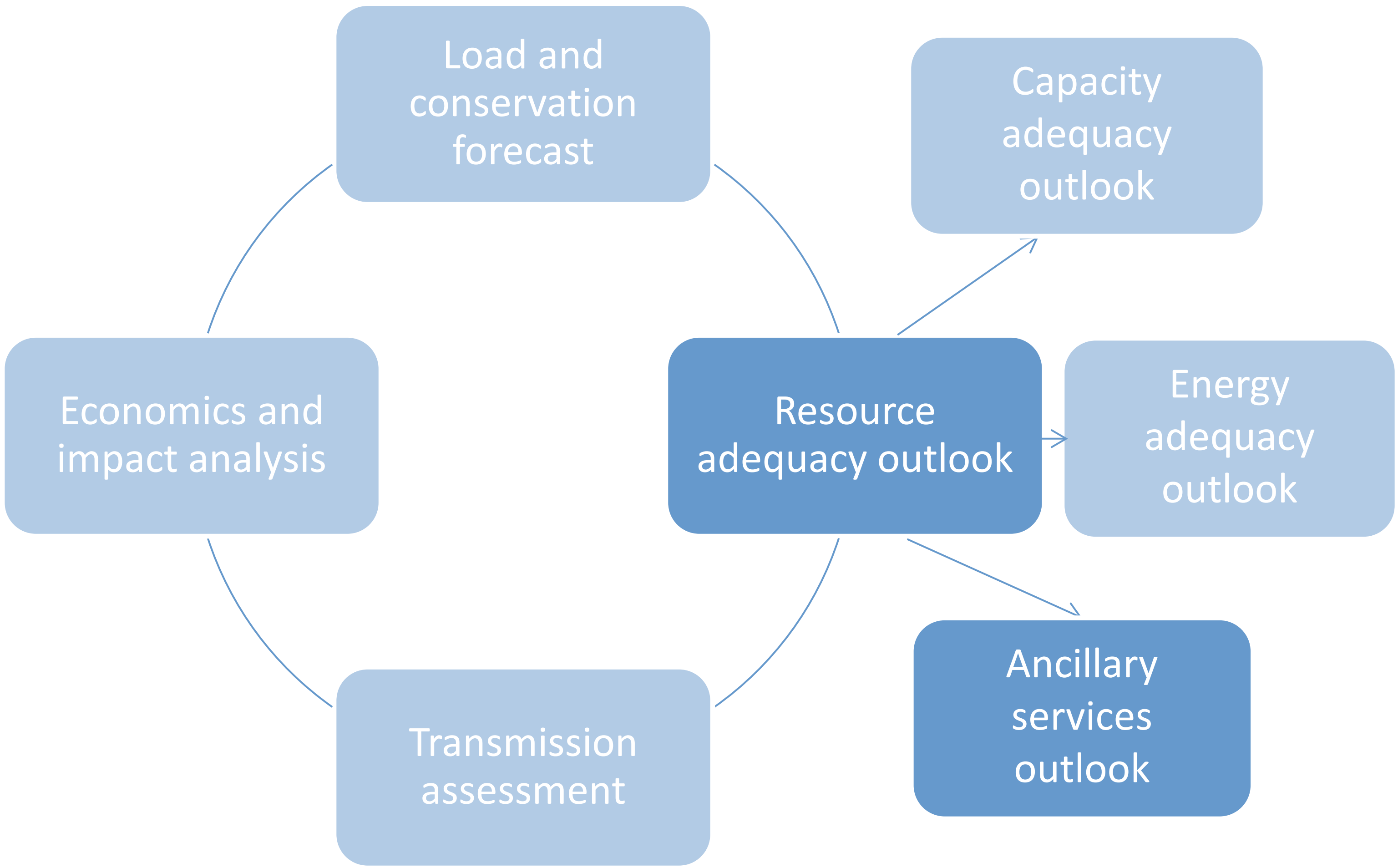
- Across the demand outlooks, it is seen that energy production from natural gas-fired generation changes the most, followed by energy production from hydroelectric generation. Nuclear and non-hydro renewable energy production remains unchanged across the demand outlooks.
- The natural gas-fired fleet 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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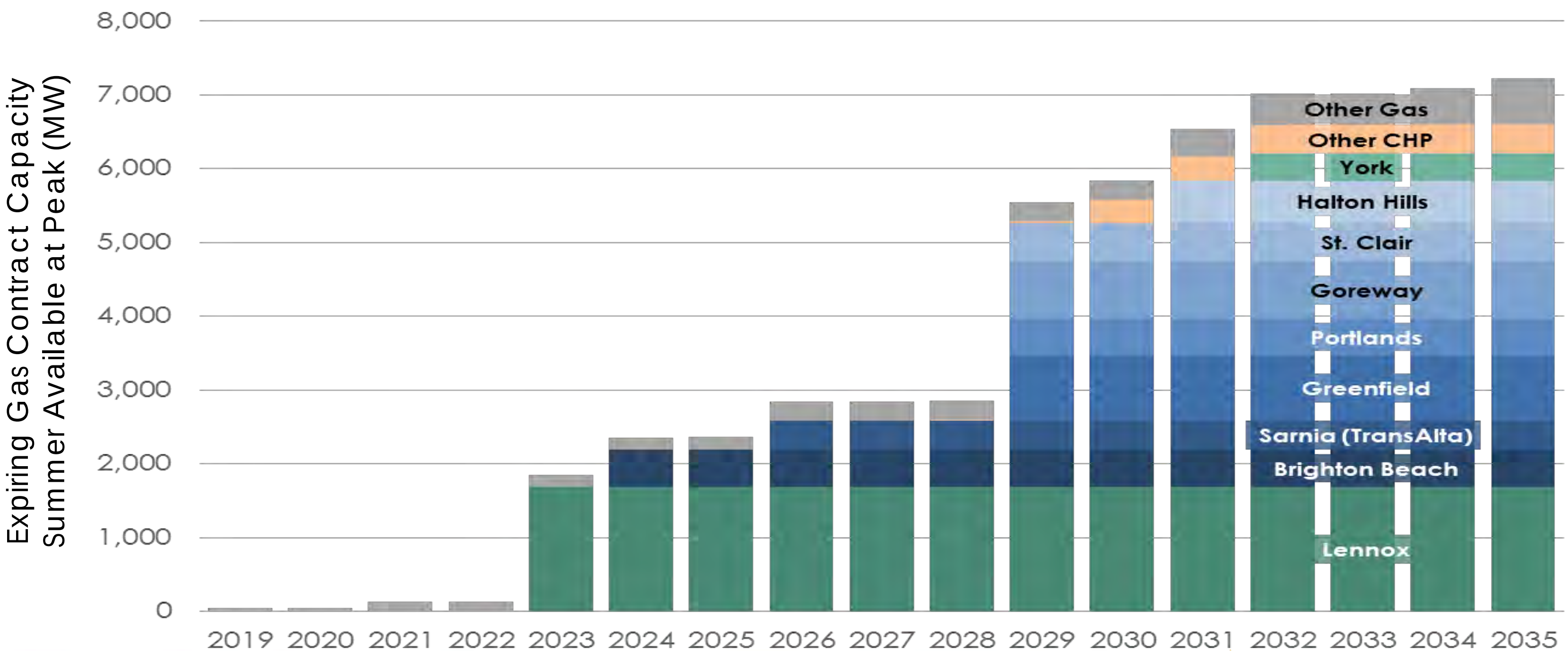
The gas generation as currently configured may not provide the operational flexibility required in the future

- 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

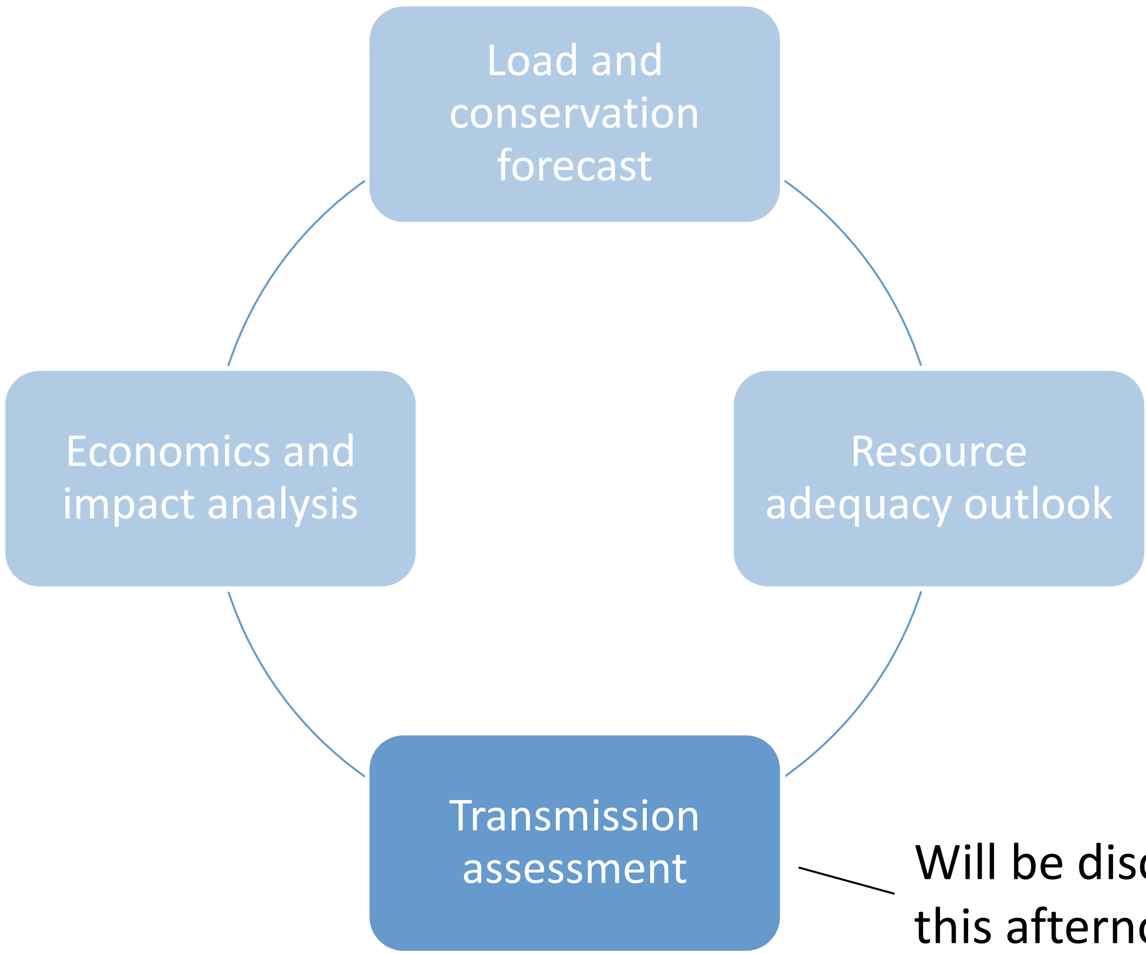
- Various sector uncertainties will impact supply availability in the coming years.

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

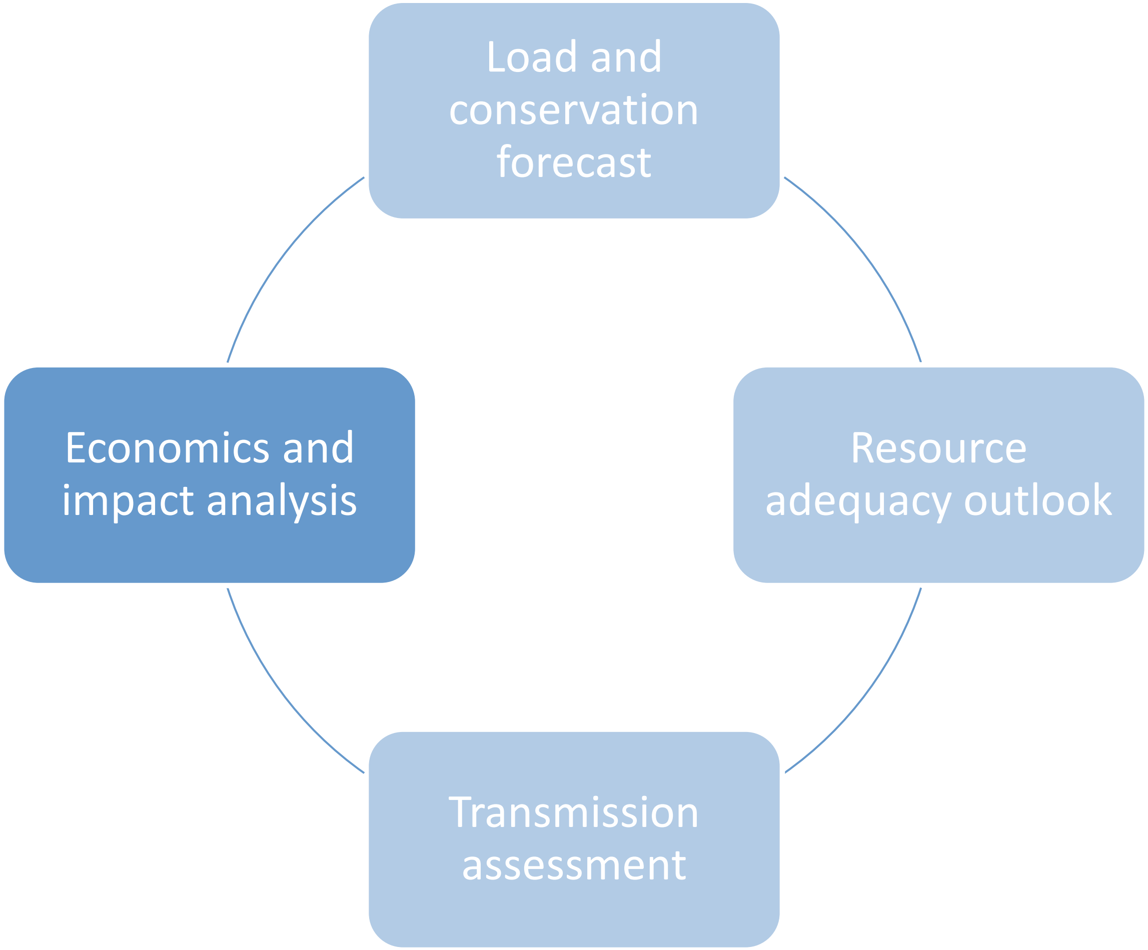
- What other key factors, uncertainties, scenarios, indicators, etc. should be considered in the resource adequacy assessment?
- How should we recognize and integrate risks related to the resource adequacy assessment?
- What additional information should the IESO provide to the market?

Bulk system planning process – Transmission assessment

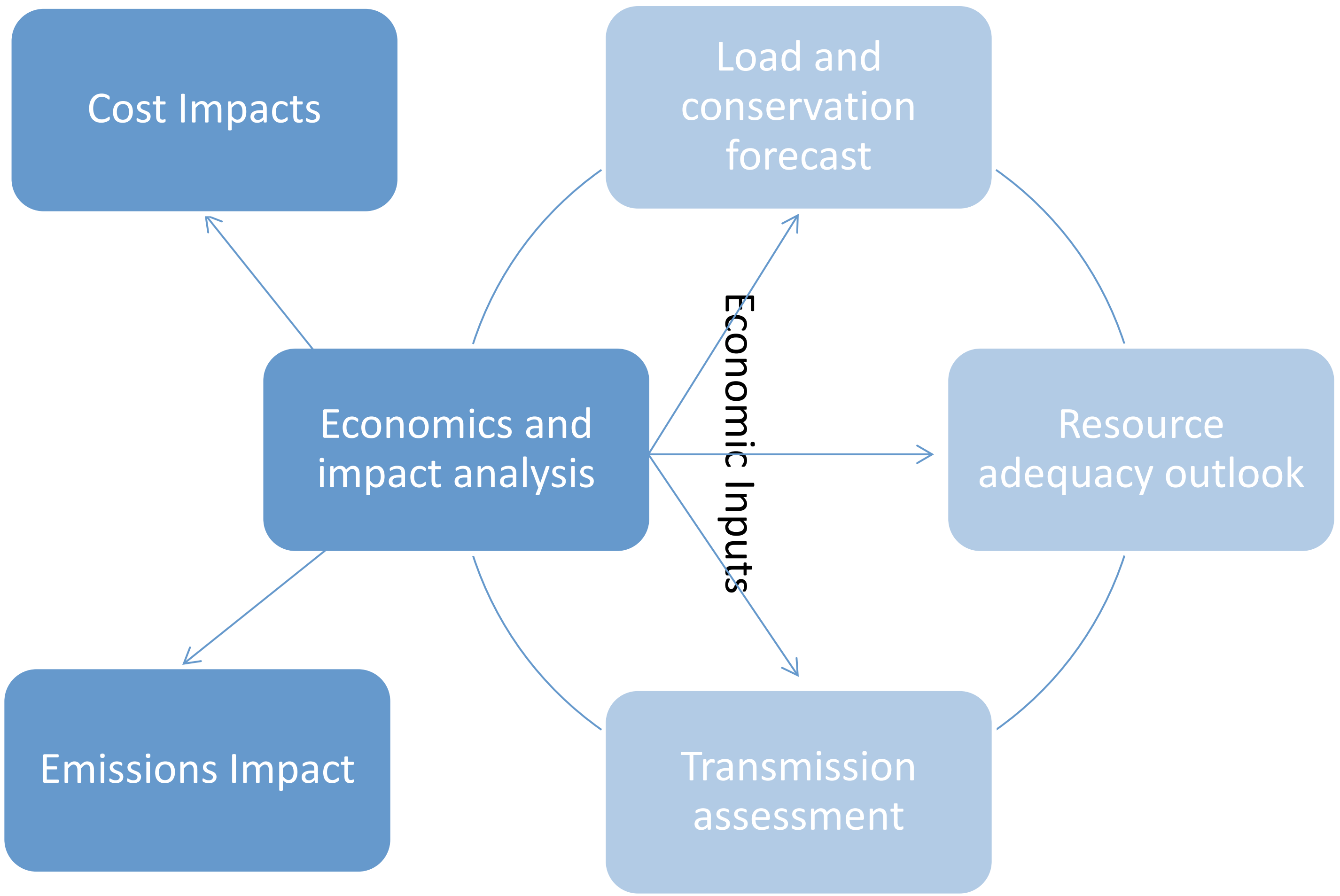


Will be discussed this afternoon

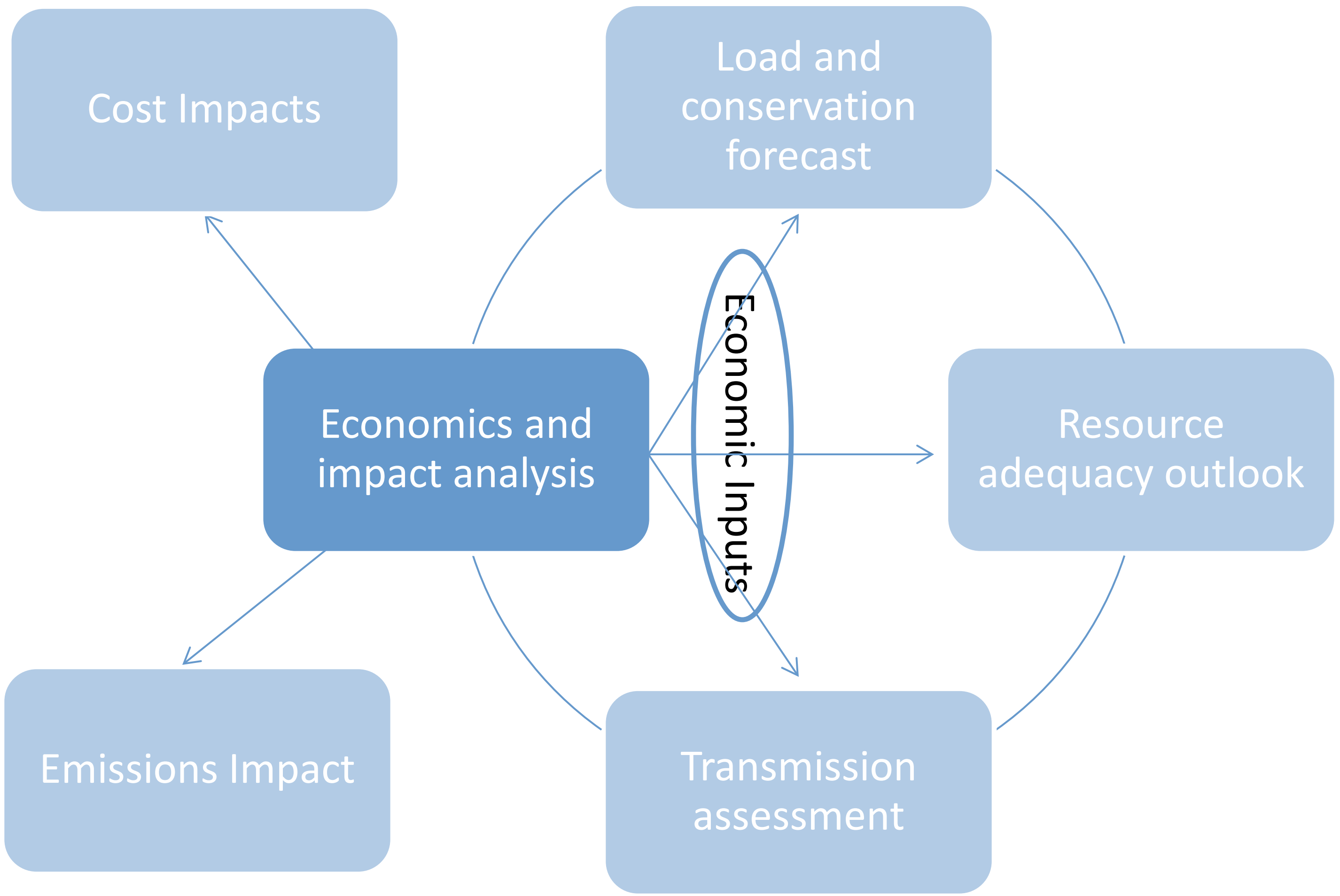
Bulk system planning process – Economics and impact analysis



What is economics and impact analysis?



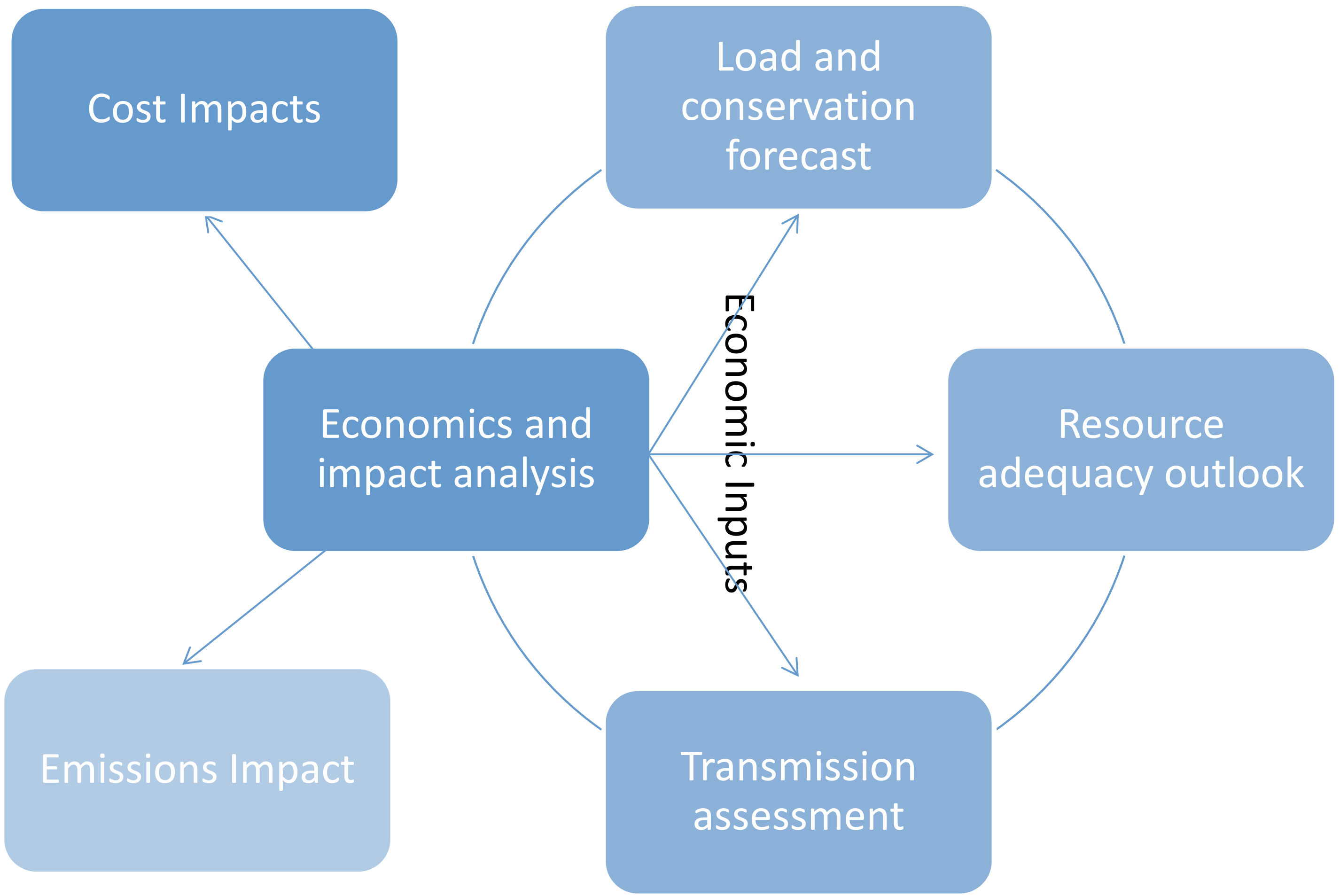
Economics and Impact Analysis – Economic Inputs



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.

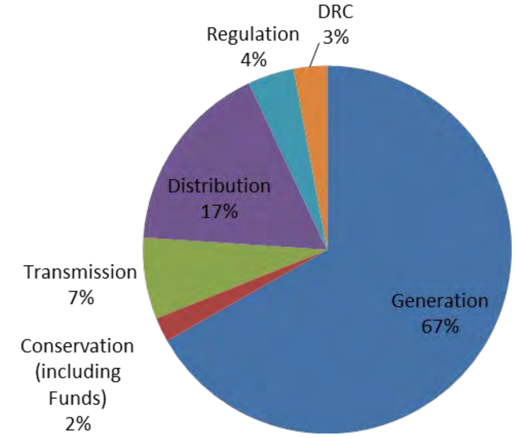
ii. Electricity Conservation: Program delivery and incentive costs recovered from electricity ratepayers, excluding equipment investments made by customers through conservation initiatives.

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



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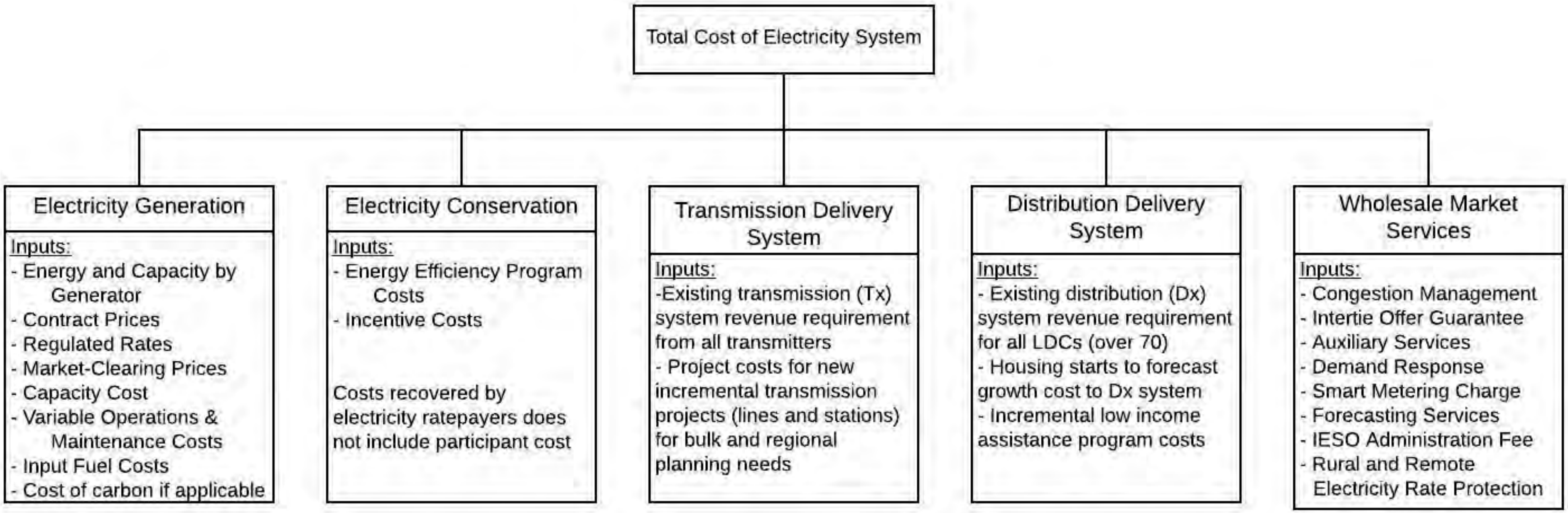
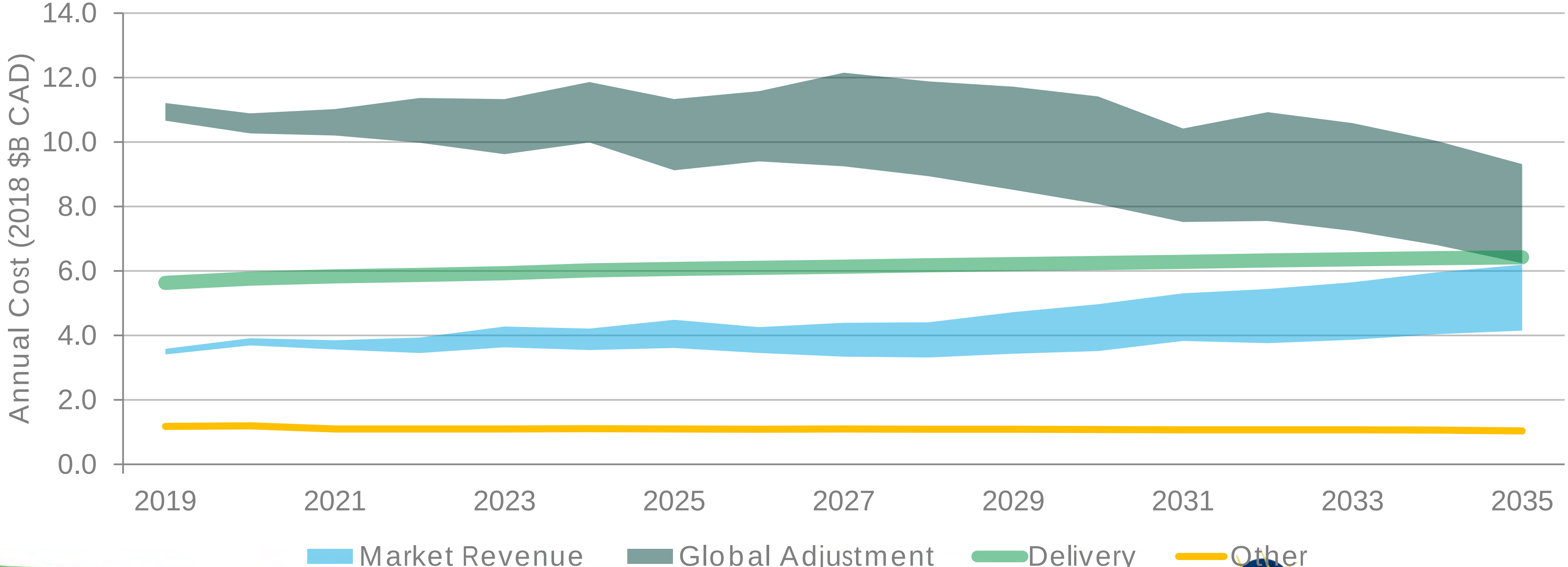
Total cost of electricity system key inputs



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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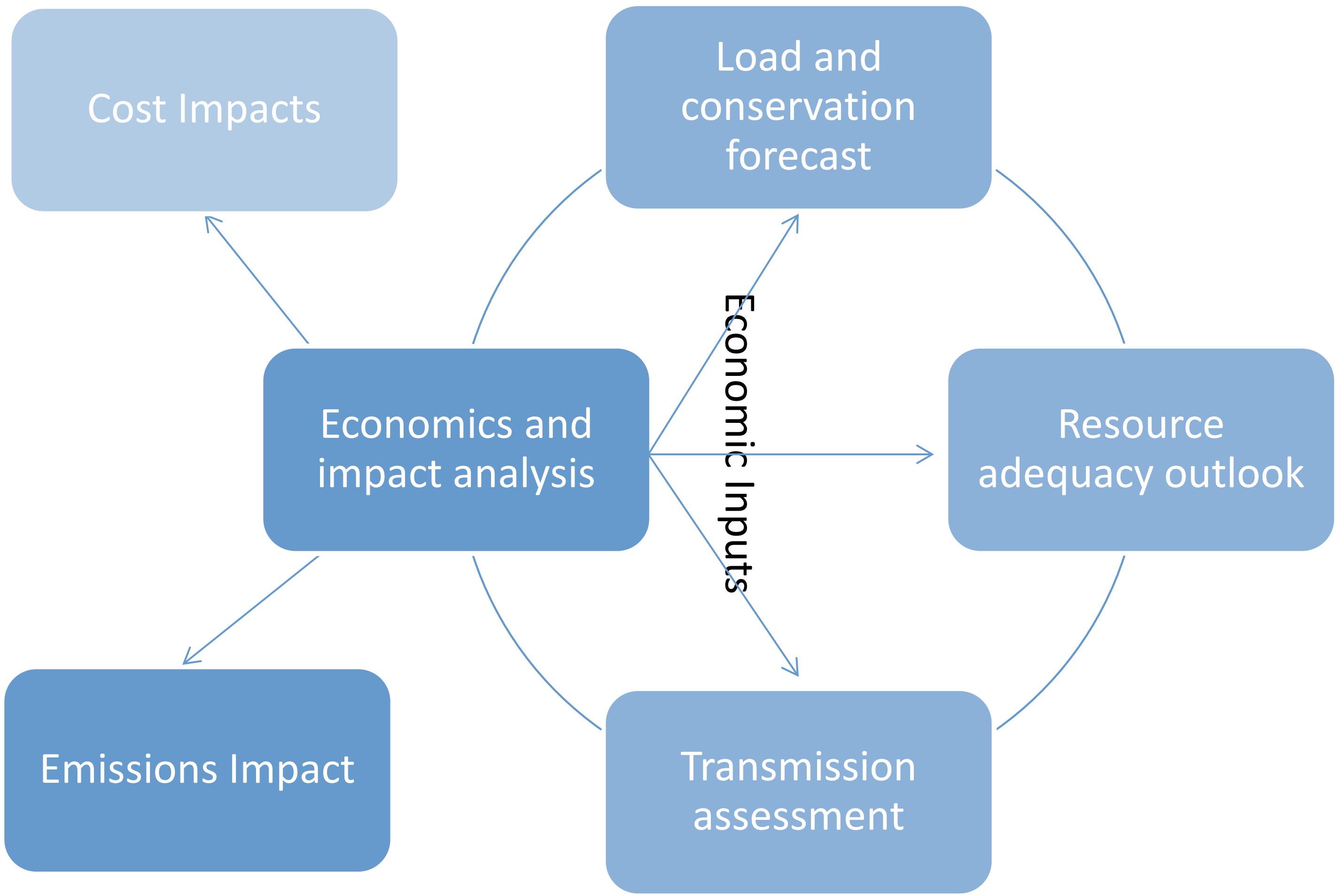
Economics and Impact Analysis – Emissions Impact



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.

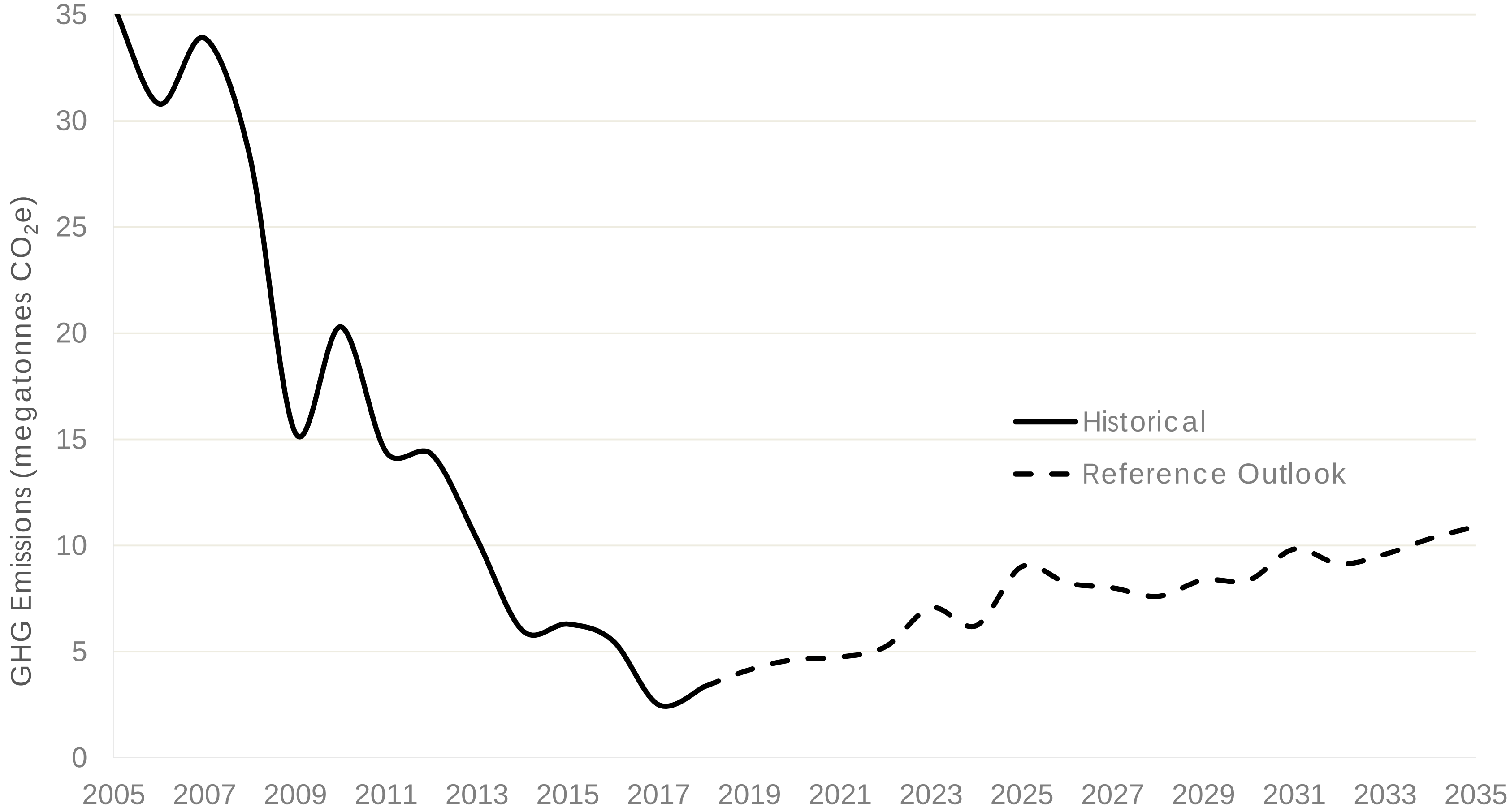
- GHG and air contaminant emissions are based on the production of electricity from emitting resources. In Ontario, the emitting resources in our supply mix include natural gas generators and the dual-fuel Lennox Generating Station.

- 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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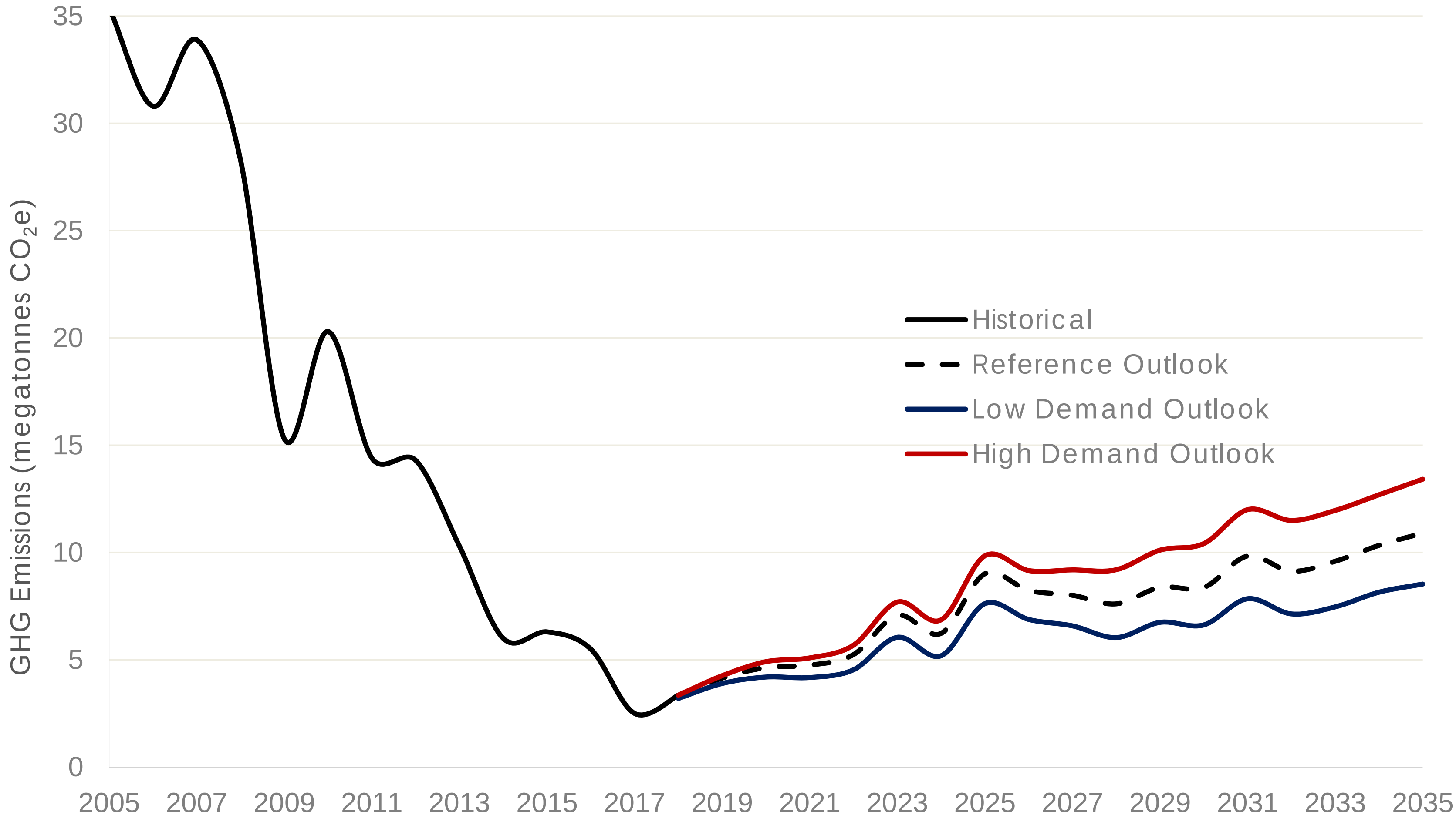
Impact of demand on greenhouse gas (GHG) emissions

- 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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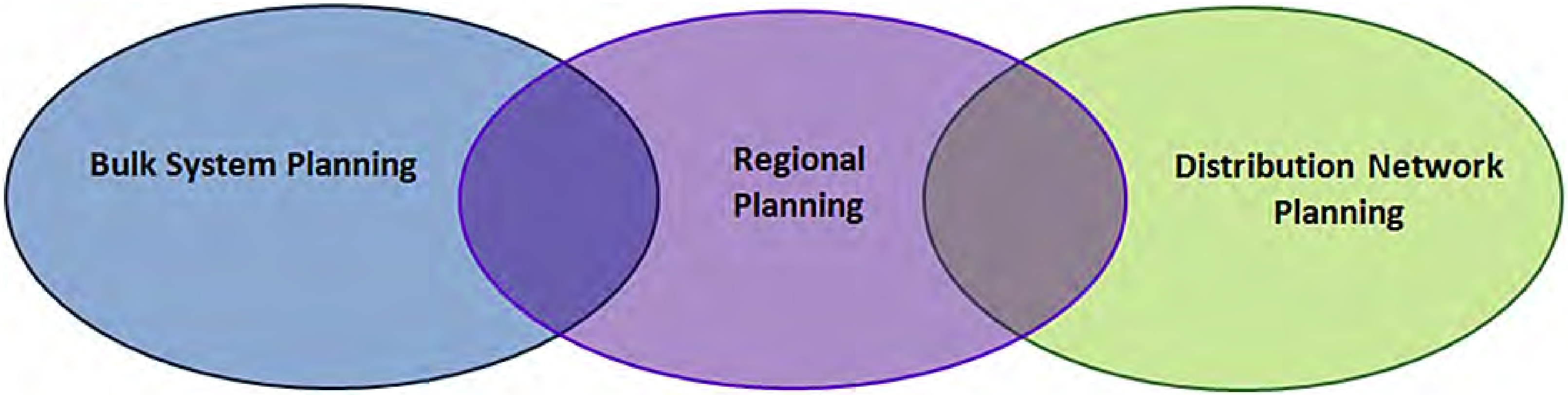
Questions

- 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

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

Distribution Network Planning

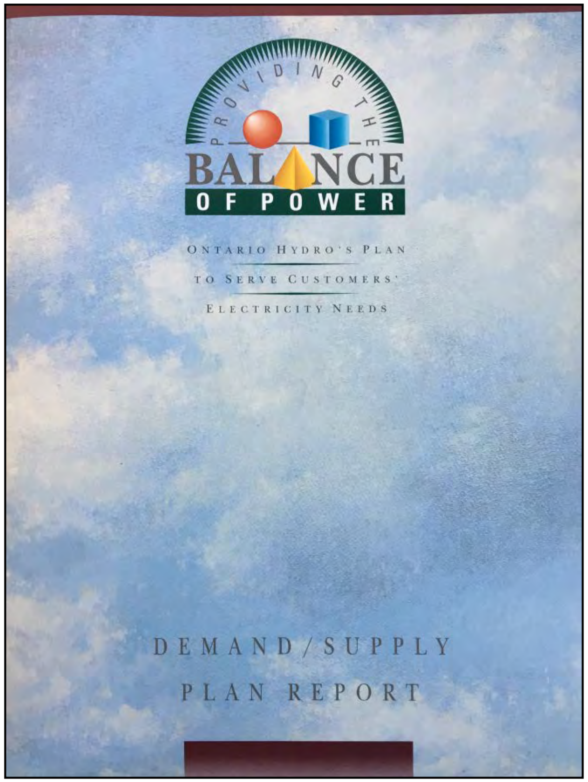
- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified Dx facilities)
- Distribution system reliability (capacity & security)
- Distribution connected generation & CDM resources
- LDC demand forecasts
- Near- & medium-term focused

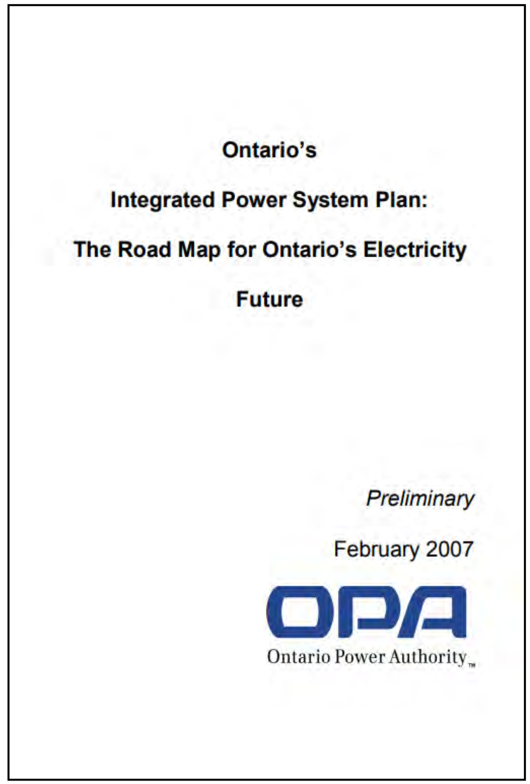
Addresses provincial electricity system needs and policy directions

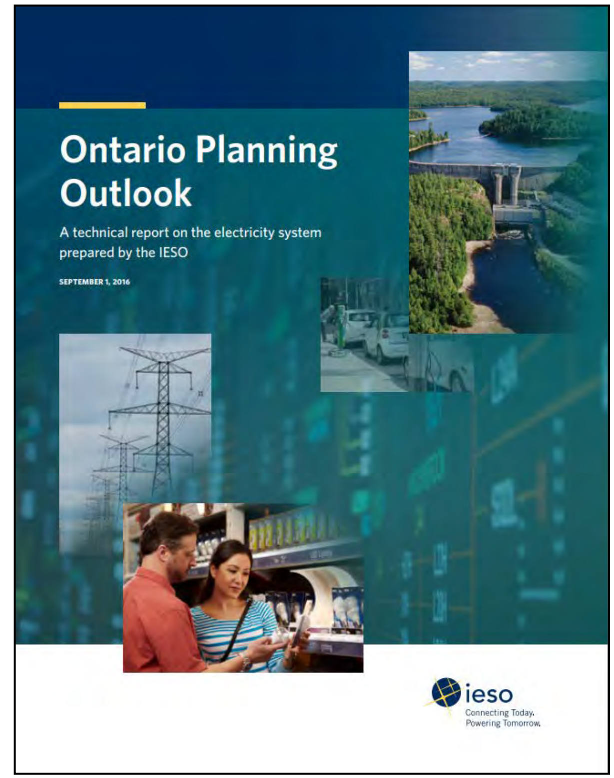
Integrates local electricity priorities with provincial policy directions & system needs

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

- 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

Enable Economic Efficiency

- 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 Sector Policy and Decision Making

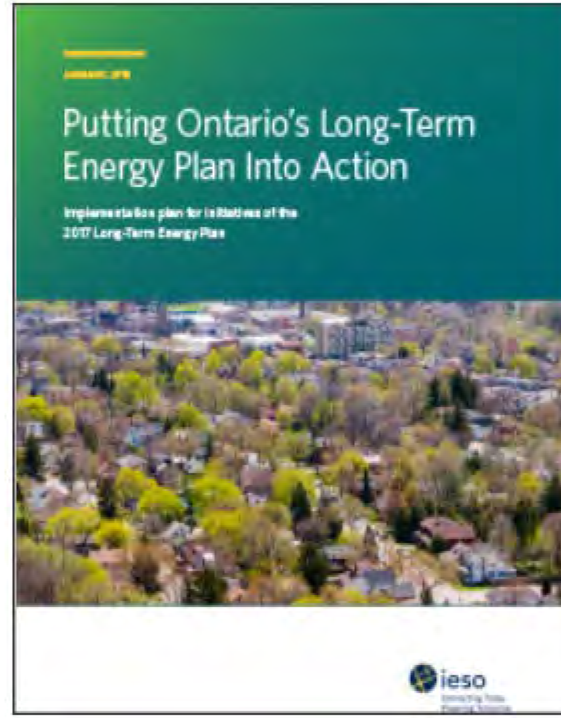
- Support policy implementation as affecting the power grid
- Provide regulatory evidence, support, testimony (e.g., OPG nuclear, hydro)

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."



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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

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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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Future

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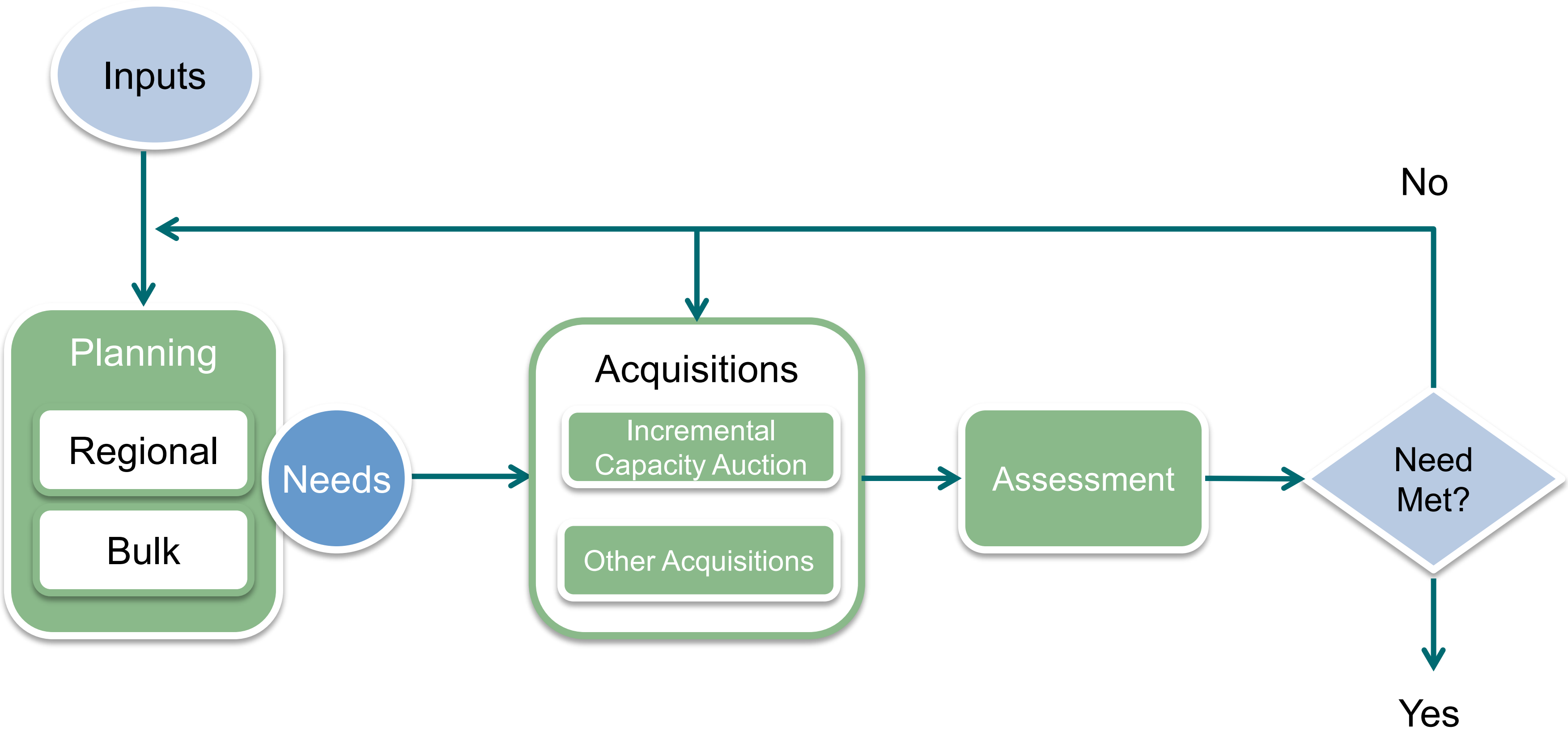
Purpose of public planning products

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

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

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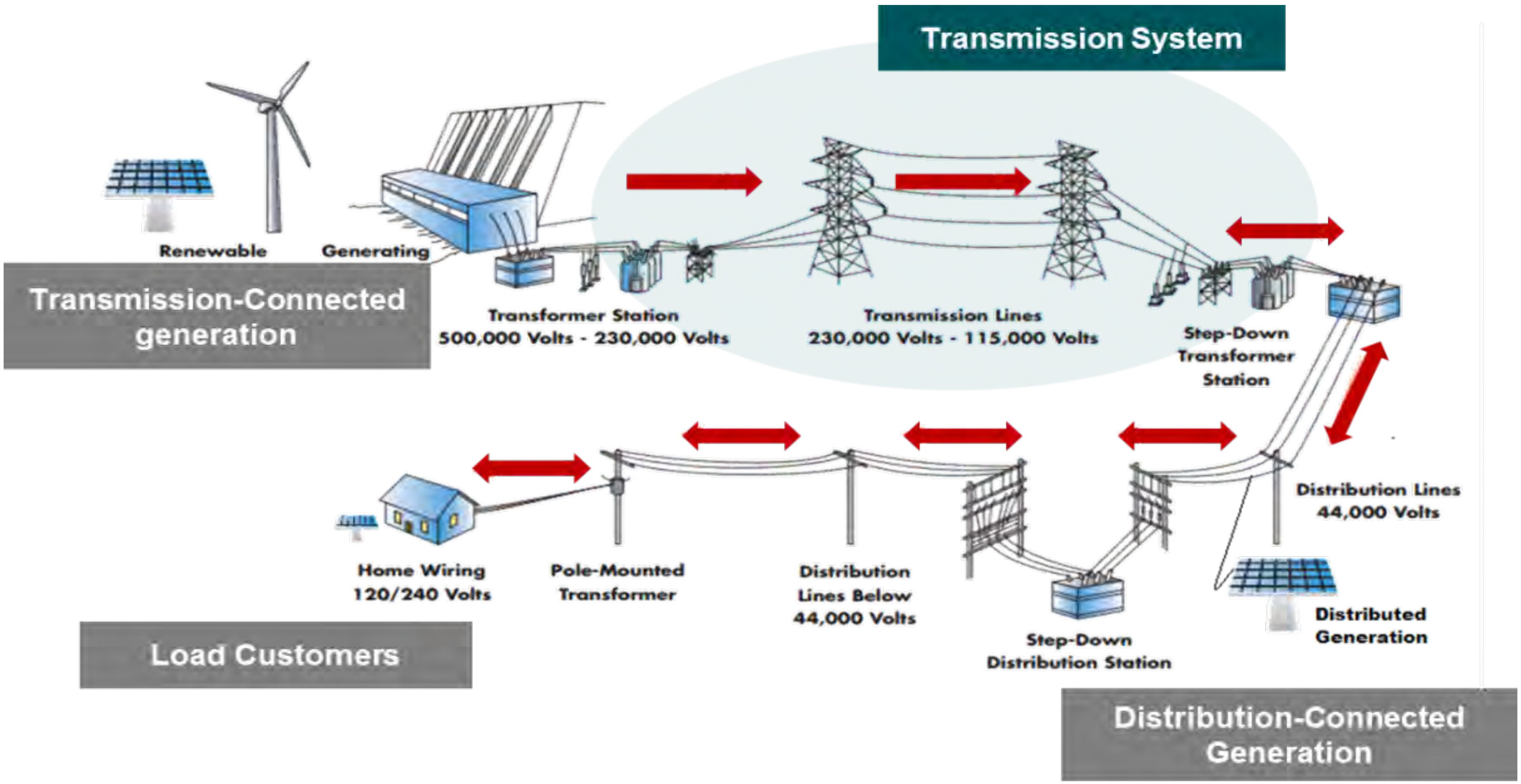
Transmission System

- 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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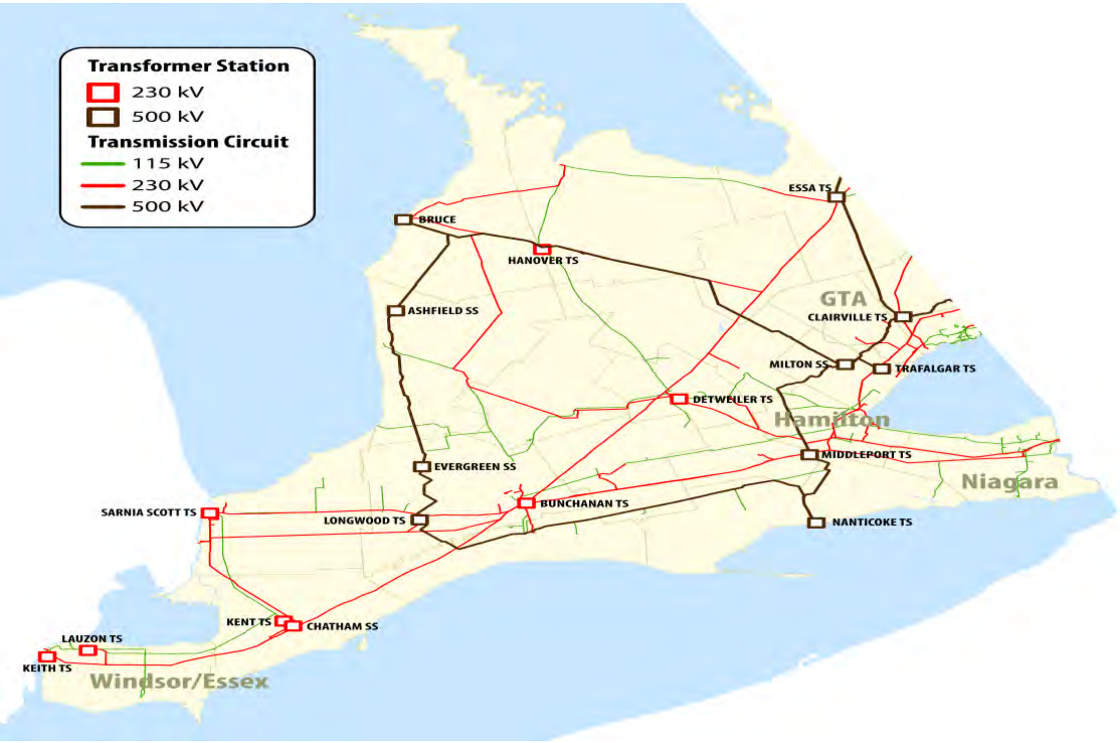
Network and radial connectivity



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

Key Participants: *IESO*

Project Development

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

Key Participants: *IESO, Transmitter*

Approval

Activities:
- Section 92 approval
- Other approvals as required

Key Participants: Transmitter, OEB

Construction

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

Key Participants: Transmitter

5-7 years

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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

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

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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

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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 16

Capacity Update

Stakeholder Advisory Committee

August 14, 2019

SAC Input

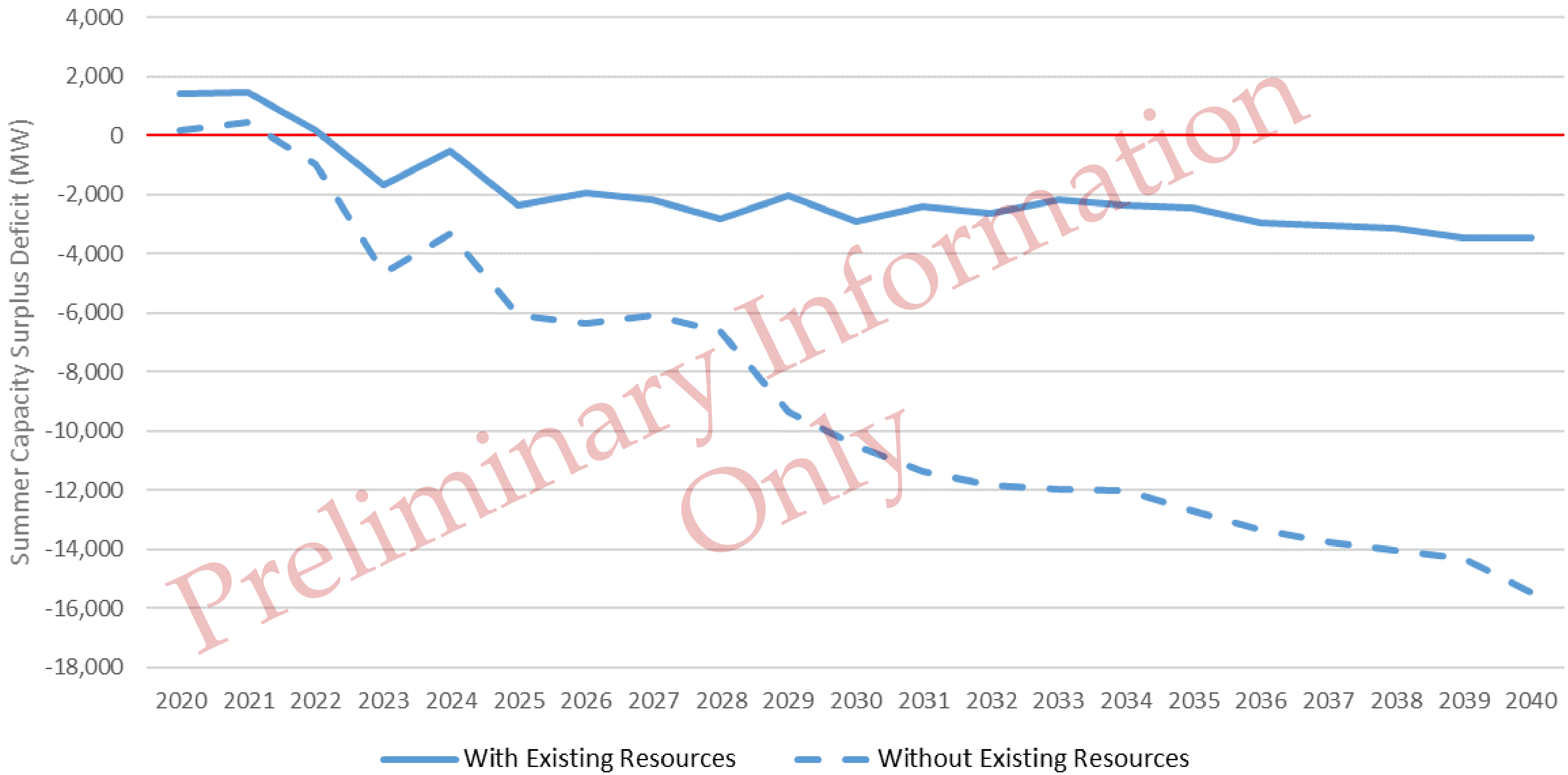
SAC's input is requested in the following areas:

- 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

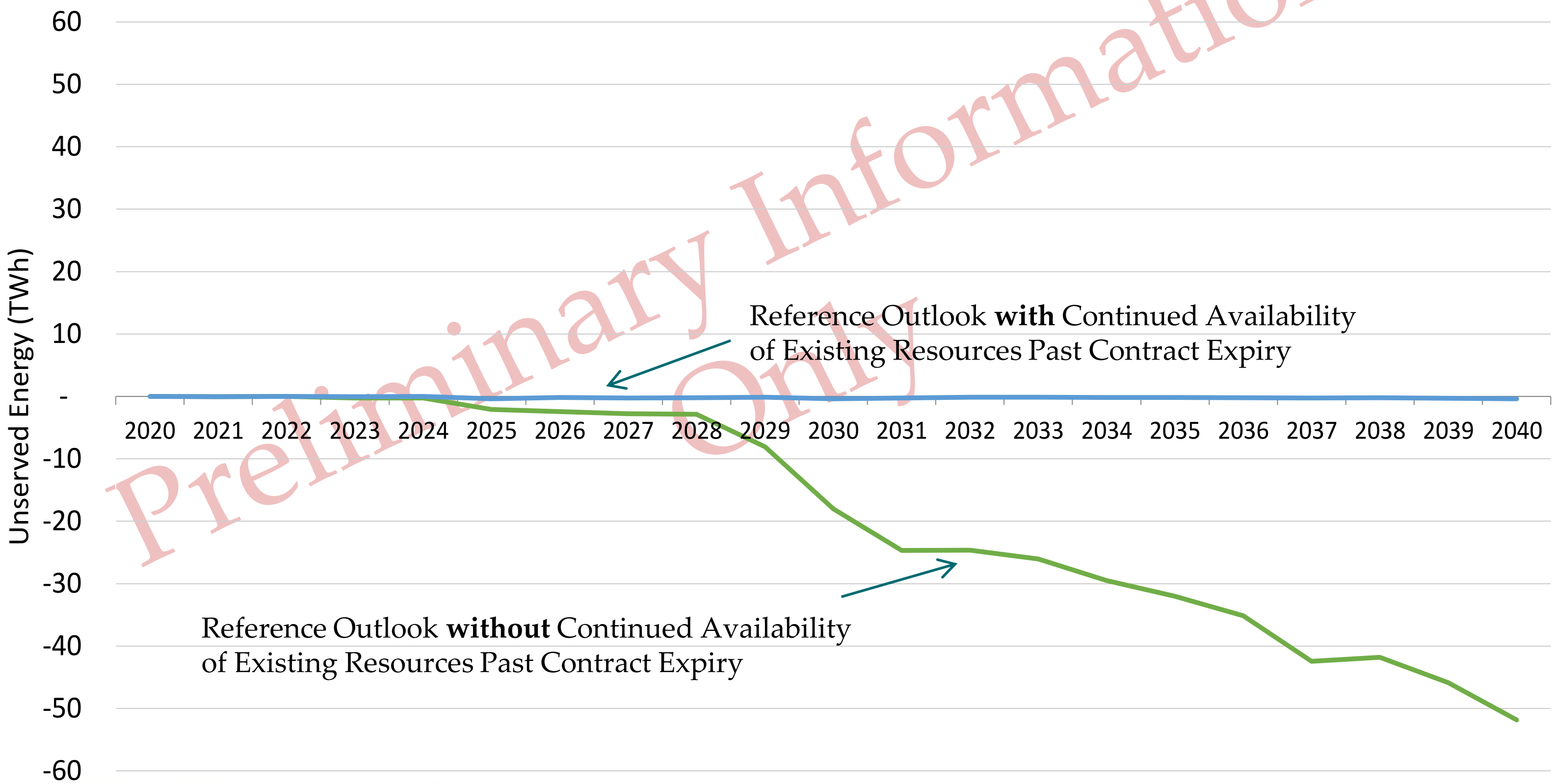
Preliminary resource adequacy outlook: winter

Notes:

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

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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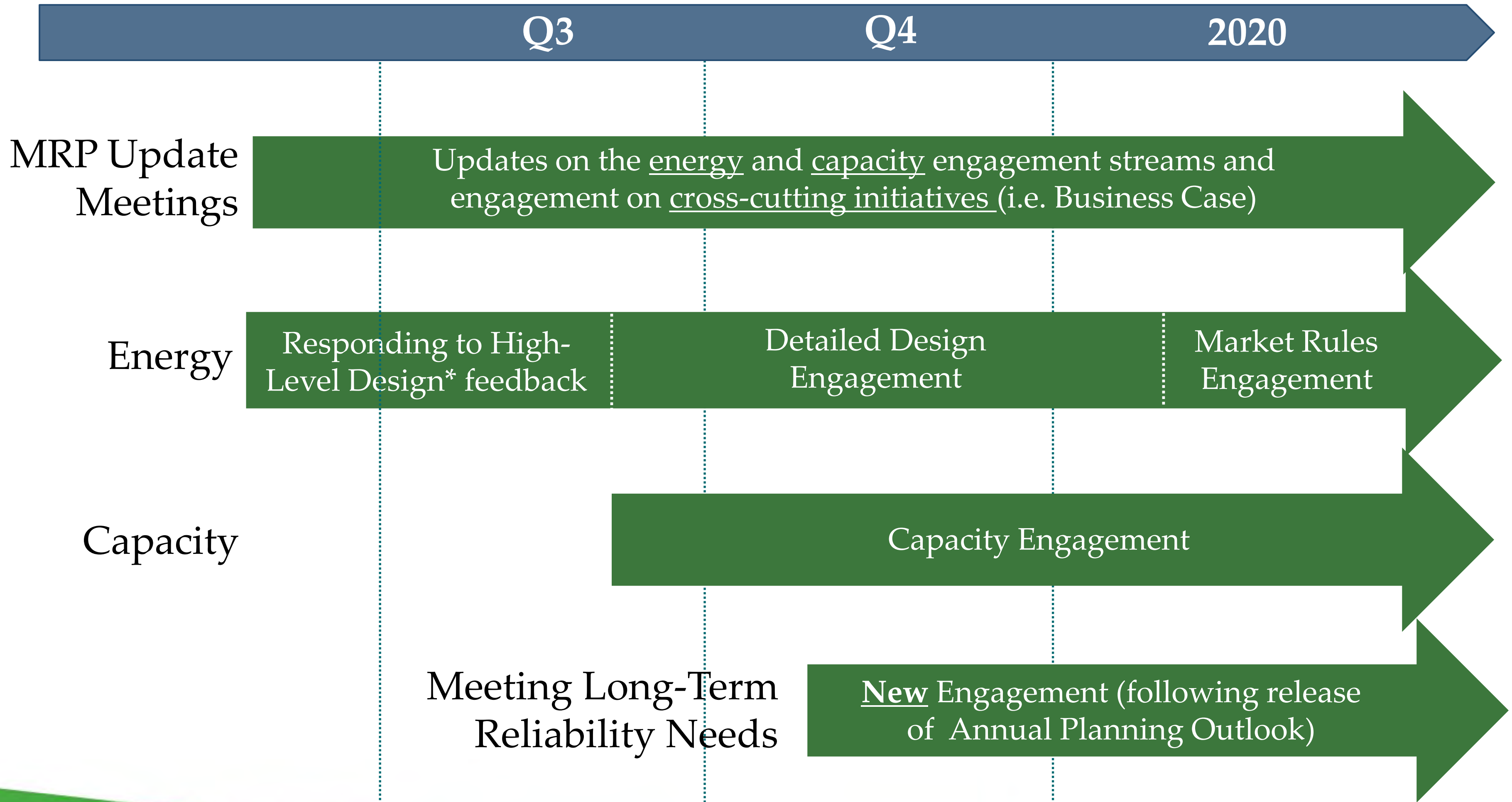
What We Heard at the MRP Update Meeting

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.

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



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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)			

SAC Input

SAC's input is requested in the following areas:

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

TAB 17

2018 Long-Term Reliability Assessment

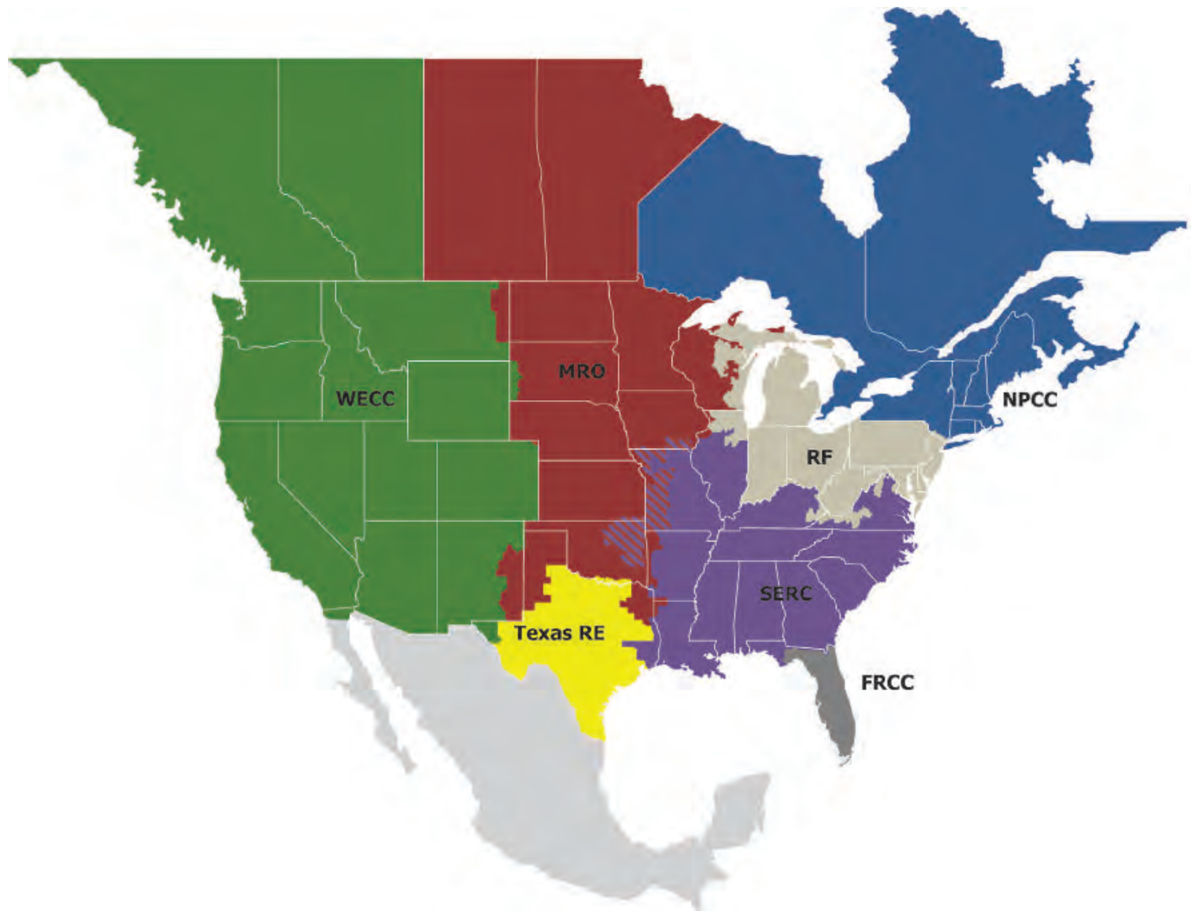
December 2018

Contents

Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities (LSEs) participate in one Region while associated Transmission Owners/Operators participate in another.



About This Assessment

Development Process

This assessment was developed based on data and narrative information collected by NERC from the seven REs on an assessment area basis. NERC staff then independently assesses this information to develop the Long-Term Reliability Assessment (LTRA) for the North American BPS. This assessment identifies trends, emerging issues, and potential risks during the 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Planning Committee (PC), supports the development of this assessment through a comprehensive and transparent peer review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts. This peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the PC and the NERC Board of Trustees (Board), who subsequently accepted this assessment and endorsed the key findings.

The LTRA is developed annually by NERC in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations,[3] also referred to as Section 215 of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Data Considerations

Projections in this assessment are not predictions of what will happen, but are based on information supplied in July 2018 about known system changes with updates incorporated prior to publication. The assessment period for the 2018 LTRA includes projections for 2019–2028; however, some figures and tables examine data and information for the 2018 year. The assessment was developed using a consistent approach for projecting future resource adequacy through the application of NERC's assumptions and assessment methods. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities, which is further explained in the "Data Concepts and Assumptions" section. Reliability impacts related to physical and cybersecurity risks are not addressed in this assessment, which is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through the Electricity-Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address these risks, including exercises and information-sharing efforts with the electric industry

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and energy, demand response (DR), resource capacity, and transmission projects. Data and information from each NERC Region are also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and the portion of Baja California Norte, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators and to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

In the LTRA, the baseline information on future electricity supply and demand is based on several assumptions, listed below:[5]

- Supply and demand projections are based on industry forecasts submitted in July 2018. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data may be submitted throughout the drafting time frame (May–September).
- Peak demand and planning reserve margins are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Region's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in-service as planned, planned outages take place as scheduled, and retirements are scheduled as proposed.

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1 NERC Rules of Procedure - Section 803

2 Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

3 Title 18, § 39.11 of the Code of Federal Regulations

4 BPS reliability, as defined in the section: "How NERC Defines Bulk Power System Reliability" on page 5, does not include the reliability of the lower-voltage distribution systems that systems use to account for 80 percent of all electricity supply interruptions to end-use customers.

5 Forecasts cannot predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50 percent probability that actual demand will be higher than the forecast midpoint and a 50 percent probability that it will be lower (50/50 forecast).

- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency and price-responsive demand response, are reflected in the forecasts of total internal demand.

How NERC Defines Bulk Power System Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

> **Adequacy:** is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
>
> **Operating Reliability:** is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components.

Regarding adequacy, system operators can and should take controlled actions or introduce procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its load-serving entity (LSE) via contract or agreement for curtailment[6]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as five percent).
- Rotating blackouts, the term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders

Under the heading of operating reliability are all other system disturbances that result in the unplanned and/or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The intent of the set of NERC Reliability Standards is to deliver an adequate level of reliability (ALR),[7] which is defined by the following BPS characteristics:

> **Adequate Level of Reliability:** the state that the design, planning, and operation of the Bulk Electric System (BES) will achieve when the following reliability performance objectives are met:
>
> - The BES does not experience instability, uncontrolled separation, cascading,[8] collapse under normal operating conditions and/or voltage when subject to predefined disturbances.[9]
> - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
> - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
> - Adverse reliability impacts on the BES following low probability disturbances (e.g., multiple elements out on the BES following contingences, unplanned and uncontrolled equipment outages, cyber security events, and malicious acts) are managed.
> - Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

[6] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards, July 3, 2018, at the following: https://www.nerc.com/files/glossary_of_terms.pdf

[7] NERC ALR: https://www.nerc.com/comm/Other/Adequate%20Level%20of%20Reliability%20Task%20Force%20%20ALRTF%20DL/Final%20Documents%20Posted%20for%20Stakeholders%20and%20Board%20of%20Trustee%20Review/2013_03_26_Technical_Report_clean.pdf

[8] NERC's Glossary of Terms defines Cascading as follows: "The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

[9] NERC's Glossary of Terms defines Disturbance as follows: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

For these less probable severe events, BES owners and operators may not be able to apply economically justifiable or practical measures to prevent or mitigate an adverse reliability impact on the BES, even if these events can result in cascading, uncontrolled separation, or voltage collapse. Less probable severe events would include, for example, losing an entire right of way due to a tornado, simultaneous or near simultaneous multiple transmission facilities outages due to a hurricane, sizeable disruptions to natural gas infrastructure impacting multiple generation resources, or other severe phenomena.

Reading this Report

This report is generally compiled with three major parts:

- **NERC Reliability Assessment**
    - Evaluate industry preparations in place to meet projections and maintain reliability
    - Identify trends in demand, supply, and reserve margins
    - Focus the industry, policy makers, and the general public's attention on significant issues facing BPS reliability
    - Make recommendations based on an independent NERC reliability assessment process
- **Emerging Reliability Issues**
    - Identify industry issues that may pose reliability issues in the future that may not be included in the current reference case
- **Regional Reliability Assessment**
    - Summary assessments for each assessment area
    - Focus on region-specific issues identified through industry data and emerging issues
    - Identify regional planning processes and methods used to ensure reliability

Executive Summary

The electricity sector is undergoing significant and rapid change, presenting new challenges and opportunities for reliability. With appropriate insight, careful planning, and continued support, the electricity sector will continue to navigate the associated challenges in a manner that maintains reliability and resilience. As NERC has identified in recent assessments, retirements of conventional generation and the rapid addition of variable resources in some areas—primarily wind and solar—are altering the operating characteristics of the grid in some areas. A significant influx of natural gas generation raises new questions about how disruptions on the pipeline system can impact the electric system reliability. Risks and corresponding mitigations may be unique to each area, and industry stakeholders and policymakers should respond with policies and plans to address these emerging issues.

This *2018 LTRA* serves as a comprehensive, reliability-focused perspective on the 10-year outlook for the North American BPS and identifies potential risks to inform industry planners and operators, regulators, and policy makers. Based on data and information collected for this assessment, NERC has identified the following five key findings:

ERCOT, MRO-MISO, and NPCC-Ontario are projected to be below the Reference Margin Level; probabilistic assessments of future conditions can highlight additional reliability challenges:

- Anticipated Reserve Margins in TRE-ERCOT are projected below the Reference Margin Level for the entire first five-year period, but additional Tier 2 resources may be advanced to preserve reliability.
- MISO and NPCC-Ontario are projected to have Anticipated Reserve Margin shortfalls beginning in 2023, but additional Tier 2 resources may be advanced to preserve reliability.
- Probabilistic evaluations identify resource adequacy risks during non-peak conditions in WECC-CAMX, starting in 2020 and increasing by 2022. While planning reserve margins are adequate for the peak hour in California, loss-of-load studies that evaluate all hours of the year have started to indicate greater risk of a supply deficit.

Reliance on natural gas generation increases in some areas with continuing resource mix changes, and fuel assurance mechanisms are being developed:

- FRCC, TRE-ERCOT, and WECC-CA-MX assessment areas are projecting natural gas generation to contribute greater than 60 percent of on-peak capacity. Natural gas generation provides important flexibility attributes that are essential for managing wind and solar variability.
- A total of 41 GW of Tier 1 natural gas generation capacity is planned through 2028.
- Fuel assurance mechanisms offer important reliability benefits, particularly in areas with high levels of natural-gas-fired generation and constrained natural gas transportation. Fuel assurance mechanisms come in many forms and have existed for decades within integrated resource planning processes. In market areas, evolving rules and mechanisms continue to target better performance as well as increasing overall fuel assurance by increasing firm pipeline transportation and maintaining back-up oil inventories for gas-fired generation.

Frequency response is expected to remain adequate through 2022:

- Eastern and Western Interconnection dynamic stability analysis shows that the projected generation mix sufficiently supports frequency after simulated disturbances despite reductions in inertia.
- Operational procedures in ERCOT are in place to limit the reliability risk resulting from degraded inertia.

Increasing solar and wind resources requires more flexible capacity to support ramp requirements:

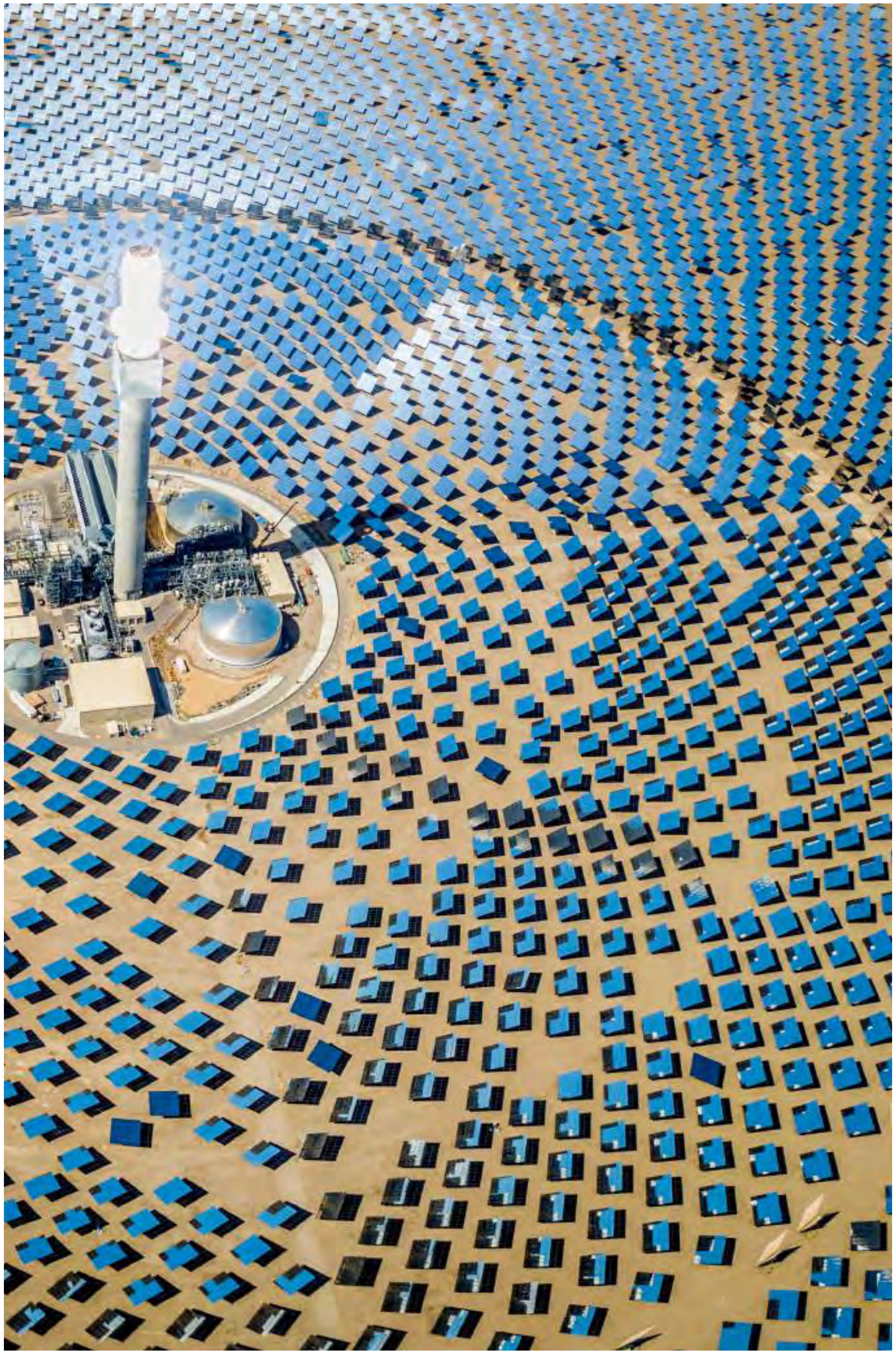
- As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability—such as supporting solar down ramps when the sun goes down and complementing wind pattern changes.
- With continued rapid growth of distributed solar, California Independent System Operator's (CAISO) three-hour ramping needs have reached 14,777 MW, exceeding earlier projections and reinforcing the need to access more flexible resources. By 2022, this need increases to 17,000.
- Changing ramping requirements induced by increasing amounts of wind is largely managed with improved forecasting. Ramp forecasts allow ERCOT operators to curtail wind production and/or reconfigure the system in response to large changes in wind output.

Over 30 GW of new distributed solar photovoltaic is expected by the end of 2023 impact system planning, forecasting, and modeling needs:

- California is projected to have over 18 GW of distributed solar photovoltaic (PV) by 2023, which is nearly 40 percent of its projected peak demand for the same period. New Jersey, Massachusetts, and New York are projected to each have between 3.5 and four GW of distributed solar PV by 2023.
- Increasing installations of distributed energy resources (DERs) modify how distribution and transmission systems interact with each other. Transmission planners and operators may not have complete visibility and control of these resources, but as growth becomes considerable, their contributions must be considered in system planning, forecasting, and modeling.

In addition to the key findings, NERC evaluated the following emerging issues that have the potential to impact reliability in the 10-year horizon:

- Bulk power storage
- Reliability coordination in the Western Interconnection
- Potential risk of significant electricity demand growth
- Reactive power requirements for transmission-connected devices
- System restoration
- Potential impact to system strength and fault current contributions



Recommendations

Based on the identified key findings, NERC formulated the following recommendations:

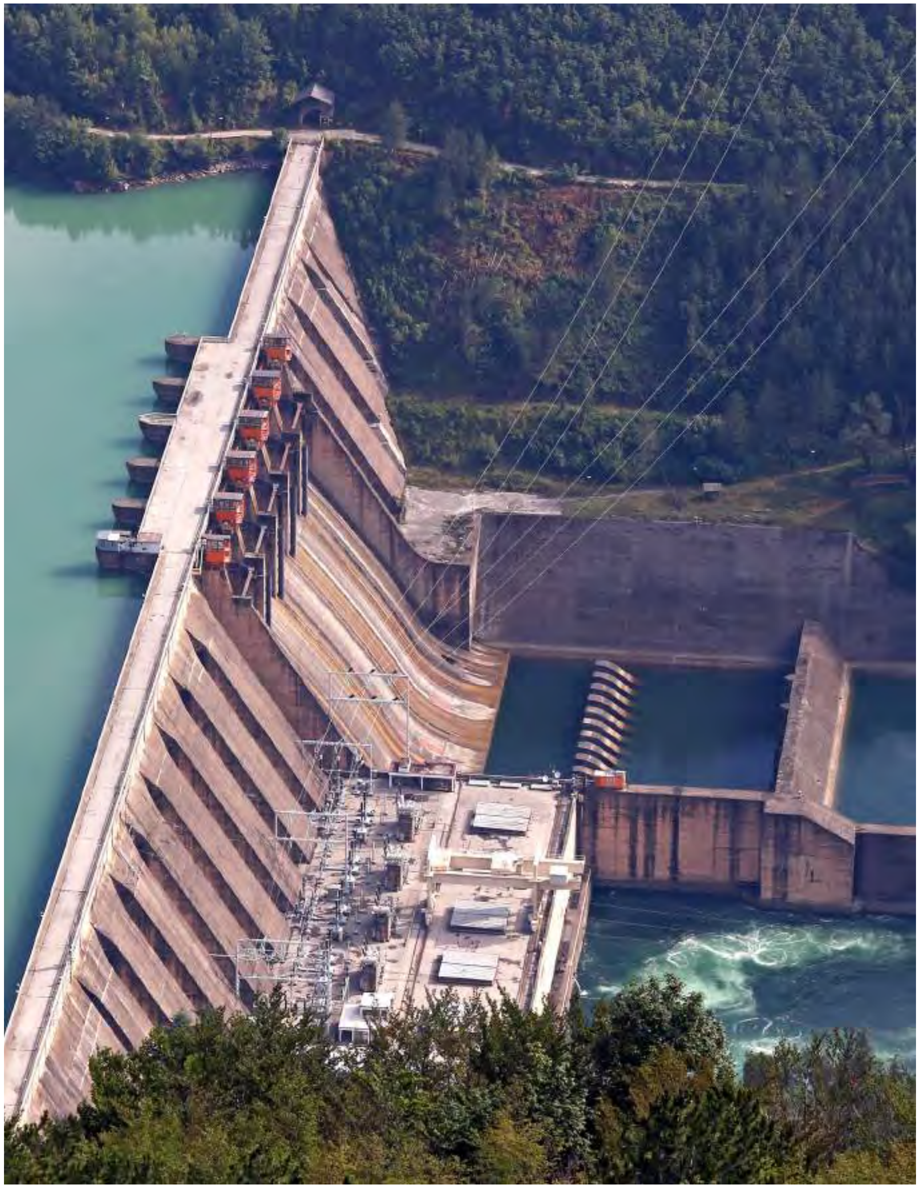
- **Enhance NERC's Reliability Assessment Process:** In addition to its capacity supply assessment, NERC's Reliability Assessment Subcommittee should lead the electric industry in developing a common approach and identify metrics to assess energy adequacy. As identified in this assessment, the changing resource mix can alter the energy and availability characteristics of the generation fleet. Additional analysis is needed to determine energy sufficiency, particularly during off-peak periods and where energy-limited resources are most prominent.

- **Develop Guidelines to Assess Fuel Limitations and Disruption Scenarios:** Given the increased reliance on natural gas generation, system planners should identify potential system vulnerabilities that could occur under extreme, but realistic, contingencies and under various future supply portfolios. In addition, NERC's Planning Committee should leverage industry experience and develop a reliability guideline that establishes a common framework for assessing fuel disruptions of various types. The industry-developed assessments can then be used to address potential regulatory needs or establish market mechanisms to better promote fuel assurance.

- **Improve Interconnection Frequency Response Modeling:** The analysis in this assessment represents the first-ever, forward-looking interconnection-wide assessment for both the Eastern and Western Interconnections. The analysis highlights several areas for improvement that include the following: improving the generation dispatch to better reflect low-inertia conditions; identifying locational constraints, particularly in the Western Interconnection; and valid representation of DERs in load models. NERC should continue working with the Eastern, Western, and Texas interconnection study groups to develop improved frequency response base case and scenario assessments.

- **Ensure System Studies Incorporate DERs:** In areas with expected growth in DERs, system planners should determine data gathering strategies to ensure the aggregate technical specifications of generation connected to local distribution grids are known to the transmission operator. This data collection is needed to ensure accurate and valid system planning models, load forecasting, coordinated system protection, and real-time situation awareness. In areas with large or emerging DER penetration, future system studies should properly account for DERs in order to accurately represent the system's behavior.

- **Flexible Ramping Resources Needed to Offset Variable Energy Production:** Presently, ramping capacity concerns are largely confined to California. However, as solar generation continues to increase in California and elsewhere across North America, system planners should ensure sufficient flexible ramping capacity, including large-scale energy storage.



Key Finding 1: ERCOT, MRO-MISO, and NPCC-Ontario Are Projected to Be below the Reference Margin Level; Probabilistic Assessments of Future Conditions can Highlight Additional Reliability Challenges

Key Points:

- Anticipated Reserve Margins in TRE-ERCOT are projected below the Reference Margin Level for the entire first five-year period.
- MISO and NPCC-Ontario are projected to have Anticipated Reserve Margin shortfalls beginning in 2023.
- Probabilistic evaluations identify resource adequacy risks during nonpeak conditions in WECC-CAMX starting in 2020 and increasing by 2022.

For the majority of the BPS, planning reserve margins appear sufficient to maintain reliability during the long-term, ten-year horizon. However, there are challenges facing the electric industry that may shift industry projections and cause NERC's assessment to change. Where markets exist, signals for new capacity must be effective for planning purposes and reflect the lead times necessary to construct new generation, any requisite natural gas infrastructure, and any associated transmission. Although generating plant construction lead times have been significantly reduced, environmental permitting and pipeline and transmission planning and approval still require significant lead times.[10]

As shown in **Figure 1.1**, all assessment areas remain above the Anticipated Reference Margin Level through 2023 with the exception of ERCOT, MISO, and NPCC-Ontario.

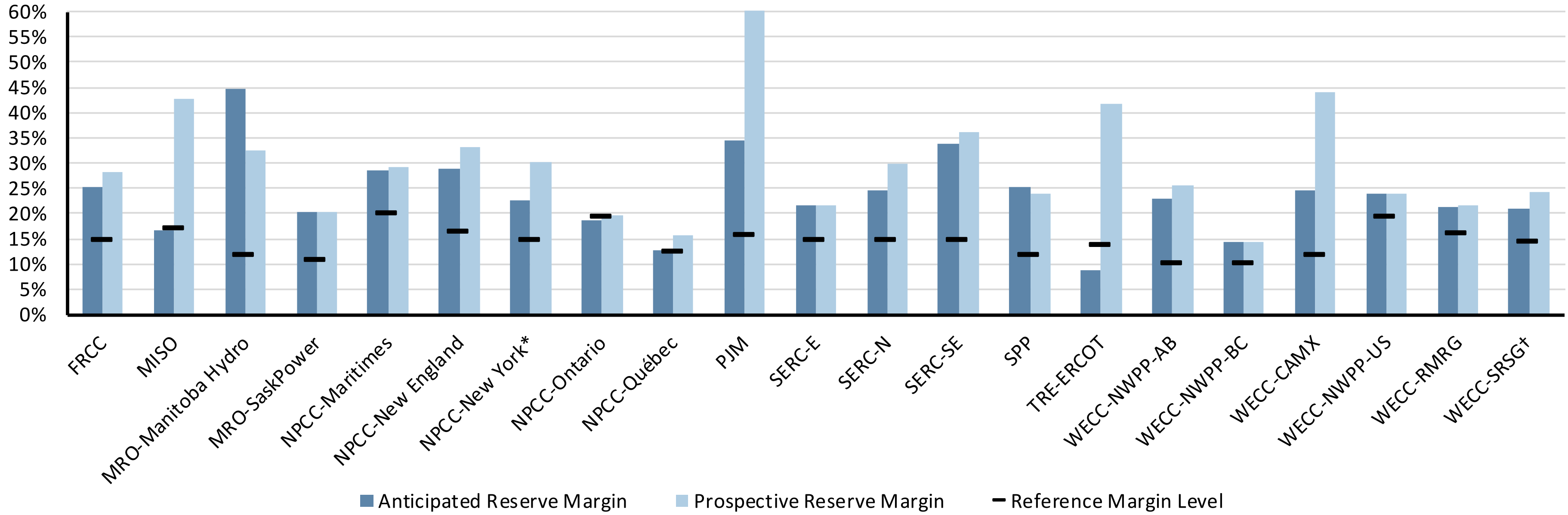


Figure 1.1: Anticipated and Prospective Reserve Margins for 2023 Peak by Assessment Area

[10] Capacity supply and planning reserve margin projections in this assessment do not necessarily take into account all generator retirements that may occur over the next 10 years or account for all replacement resources explicitly linked with potential retiring resources. While some generation plants have already announced and planned for retirement, there are still many economically vulnerable generation resources that have not determined and/or announced their plans for retirement.

How NERC Evaluates Resource Adequacy: NERC assesses resource adequacy by evaluating each assessment area's planning reserve margins relative to its Planning Reference Margin Level—a deterministic method based on traditional capacity planning. The projected resources are reduced by known operating limitations (e.g., fuel availability, transmission and environmental limitations) and compared to the Reference Margin Level, which represents the desired level of risk based on a probability-based loss of load analysis.

On the basis of the five-year projected reserves compared to the established Reference Margin Level, as shown in Figure 1.1, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: Anticipated Reserve Margin is greater than Reference Margin Level and there is a high degree of expectation in meeting all forecast parameters.

Marginal: Anticipated Reserve Margin is greater than Reference Margin Level and there is a low degree of expectation in meeting all forecast parameters, or Anticipated Reserve Margin is slightly below the Reference Margin Level and additional and sufficient Tier 2 resources are projected.

Inadequate: Anticipated Reserve Margin is significantly less than Reference Margin Level and load interruption is likely.

The results of NERC's determination is shown in Table 1.1 on the next page.

As part of NERC's assessment, Table 1.1 identifies these areas as "Marginal" with all other areas identified as "Adequate" through 2023. While MISO and NPCC-Ontario show only a very small shortfall, TRE-ERCOT shows a shortfall of over 4,000 MW.

Table 1.1: NERC's Risk Determination of All Assessment Areas Five-Year Projected Reserve Margins

Assessment Area	2023 Peak Anticipated Reserve Margin	2023 Reference Margin Level	Expected Capacity Surplus or Shortfall (MW)	Assessment Result Through 2023
FRCC	25.33%	15.00%	4,868	Adequate
MRO-MISO	16.84%	17.10%	-313	**Marginal**
MRO-Manitoba	44.60%	12.00%	1,413	Adequate
MRO-SaskPower	20.29%	11.00%	369	Adequate
NPCC-Maritimes	28.45%	20.00%	443	Adequate
NPCC-New England	28.98%	16.36%	3,070	Adequate
NPCC-New York	22.74%	15.00%	2,432	Adequate
NPCC-Ontario	18.62%	19.43%	-175	**Marginal**
NPCC-Quebec	12.86%	12.61%	92	Adequate
PJM	34.53%	15.80%	27,326	Adequate
SERC-E	21.48%	15.00%	2,793	Adequate
SERC-N	24.58%	15.00%	3,861	Adequate
SERC-SE	33.77%	15.00%	8,757	Adequate
SPP	25.15%	12.00%	7,032	Adequate
TRE-ERCOT	8.62%	13.75%	-4,018	**Marginal**
WECC-AB	22.83%	10.14%	1,564	Adequate
WECC-BC	14.23%	10.14%	499	Adequate
WECC-CAMX	24.51%	12.02%	6,267	Adequate
WECC-NWPP US	23.82%	19.56%	2,138	Adequate
WECC-RMRG	21.14%	16.07%	669	Adequate
WECC-SRSG	20.90%	14.47%	1,654	Adequate

Planning Reserve Margins in TRE-ERCOT Are Projected below the Reference Margin Level for the Entire First Five Year Period.

For the second year in a row, the projected Anticipated Reserve Margins in TRE-ERCOT fall below the Reference Margin Level of 13.75 percent starting in Summer 2018 and remains below for the duration of the LTRA forecast period (**Figure 1.2**). The 2019 Anticipated Reserve Margin is projected to be 11.2 percent and goes below 10 percent past the Summer 2022. The shortfall is mainly due to the retirement of over 4,000 MW of coal and natural gas resources in late 2017/early 2018 as well as reported delays in planned resource capacity construction by project developers.

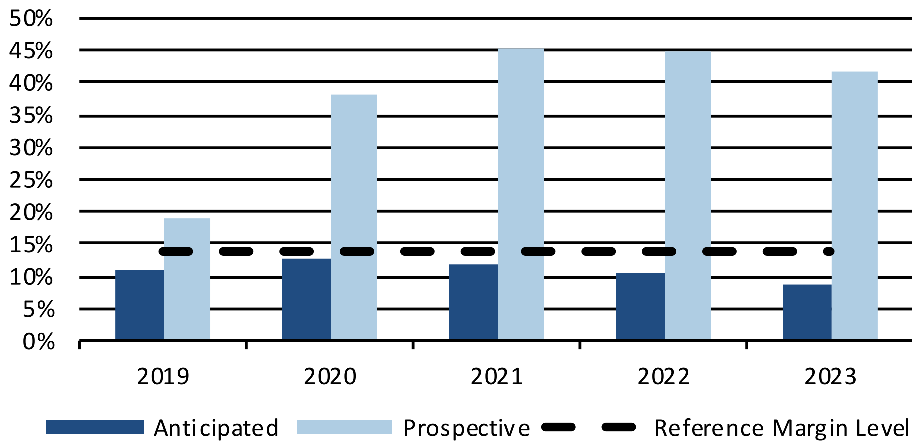


Figure 1.2: TRE-ERCOT 5-year Projected Reserves (Anticipated and Prospective Reserve Margins)

To respond to such cyclical resource investment and retirement trends, the ERCOT market is designed to incentivize increases in supply along with temporary reductions in demand to maintain the reliability of the system. For example, there are programs operated by ERCOT, retail electric providers, and distribution utilities that compensate customers for reducing their demand or operating their own generation in response to market prices and anticipated capacity scarcity conditions. ERCOT also has operational tools available to maintain system reliability, such as using DR qualified to provide ancillary services, requesting emergency power across the direct current (dc) ties to neighboring grids, and requesting emergency support from available switchable generators currently serving non-ERCOT grids. However, insufficient reserves during peak hours could lead to an increased risk of entering emergency operating conditions, including the possibility of rotating firm load outages.

Trends for the ERCOT area since 2010 indicate that the reserve margin shortfalls in the long-term outlook represent a "new normal" (**Figure 1.3**). In many ways, this is the expected outcome of managing resource adequacy through an energy-only market construct.[11] In Texas, regulators ensure reliability through a mechanism called scarcity pricing, which allows real-time electricity prices to reach as high as $9,000/megawatt hour (MWh) in response to capacity shortage conditions. Instead of guaranteeing generation revenue through a capacity market, the opportunity of high prices is intended to incentivize generators to build new plants and keep them ready to operate. Recent performance over the last several years has proven the ERCOT market and system operations to be successful with no load shedding events.

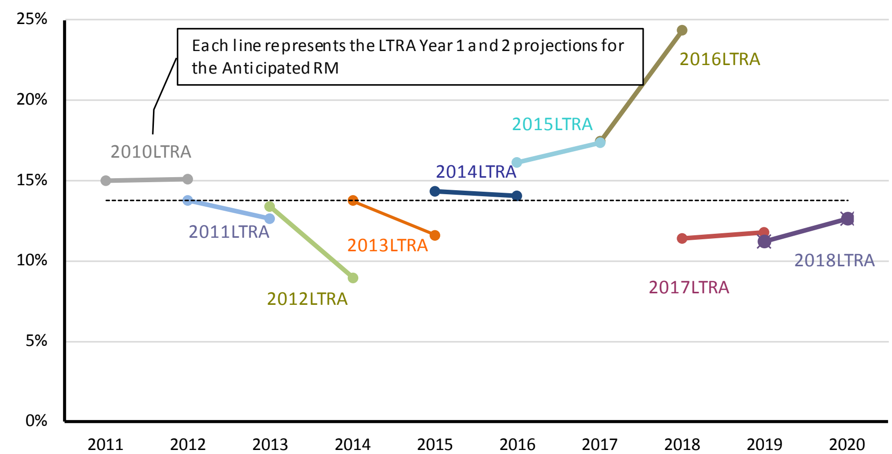


Figure 1.3: TRE-ERCOT Reserve Margin Trends since 2010

[11] Energy-only markets pay generators only when they provide power on a day-to-day basis. Conversely, capacity markets aim to ensure resource adequacy by paying participants to commit generation for delivery years into the future.

MISO and NPCC-Ontario Are Projected to have Anticipated Reserve Margin Shortfalls beginning in 2023

MISO

MISO projects a regional surplus for the summer peaks occurring through 2022 and then falling below the Reference Margin Level for the summer of 2023 (**Figure 1.4**). The 2023 summer peak Anticipated Reserve Margin is projected to be 16.8 percent. These results are driven by a number of factors:

- A decrease in resources committed to serving MISO load mainly focused in most of Illinois and Michigan (Zones 4 and 7)
- An increase in reserve requirements (15.8 percent to 17.1 percent) due to higher forced outage rates, resource mix changes, and unit retirements/suspensions[12]
- An increase in new committed resources from DR and behind-the-meter resources

Individually, all zones within MISO are sufficient from a resource adequacy point of view in the near-term when available capacity and transfer limitations are considered. Each zone within the MISO footprint is expected to have sufficient resources within their boundaries to meet their local resource requirement, which must be contained within its boundaries. Projected regional shortages identified in this assessment are being rectified by MISO and the state regulatory agencies through engagement with stakeholders in a number of resource adequacy forums. For example, there are opportunities to advance Tier 2 and Tier 3 resources to mitigate the projected long term resource shortfalls.

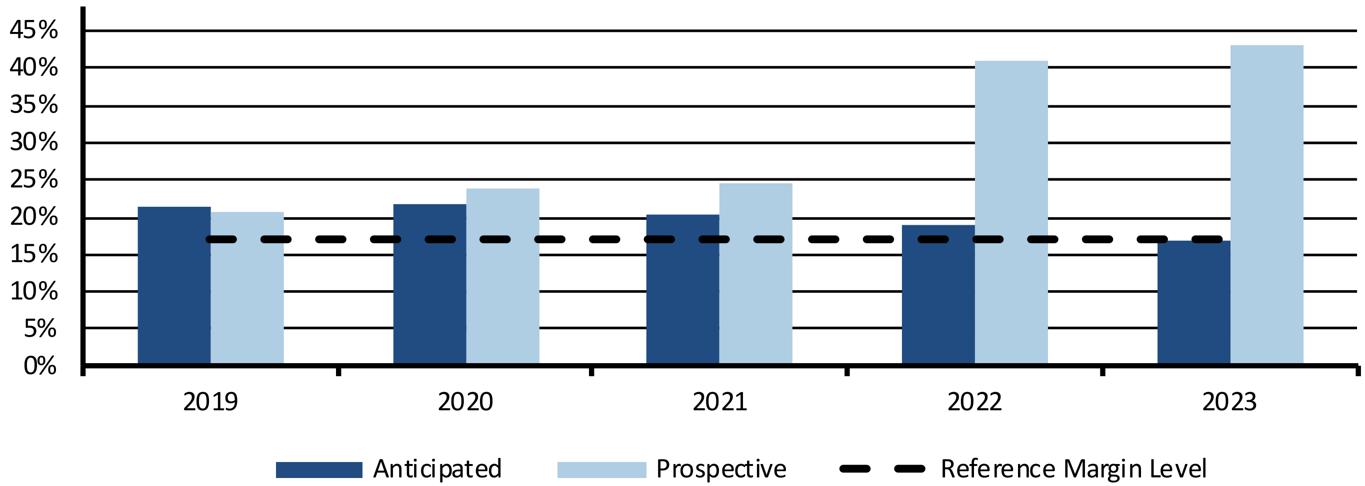


Figure 1.4: MISO 5-year Projected Reserve Margin through 2023 (Anticipated and Prospective Reserve Margins)

Operating at or near the Reference Margin Level creates a new operating reality for MISO members where the use of all resources available on the system and emergency operating procedures are more likely. This reality will lead to a projected dependency on use of DR and behind-the-meter resources.

[12] As directed under Module E-1 of the MISO Tariff, MISO performs a probabilistic analysis annually using the loss of load expectation (LOLE) study to determine the appropriate Reference Margin Level. MISO calculates the Reference Margin Level such that the LOLE for the next planning year is one-day-in-10 years, or 0.1 days per year.

NPCC-Ontario

The Anticipated Reserve Margin falls below the Reference Margin level in the mid-2020s to 18.6 percent (**Figure 1.5**). This is driven by nuclear retirements, the nuclear refurbishment program, and the assumption that certain generation resources will not be available once their generation contracts have expired. That said, there are uncertainties in the projections that could see the shortfall grow or shrink. As a result, the Independent Electricity Service Operator (IESO) will continue to update and refine its forecasts to gain more certainty about the size of the gap. The development of a capacity auction is underway as a means to acquire any necessary resources for 2023, and IESO expects that there are sufficient resources that can be developed with a three-year lead time to meet at 2023 resource gap.

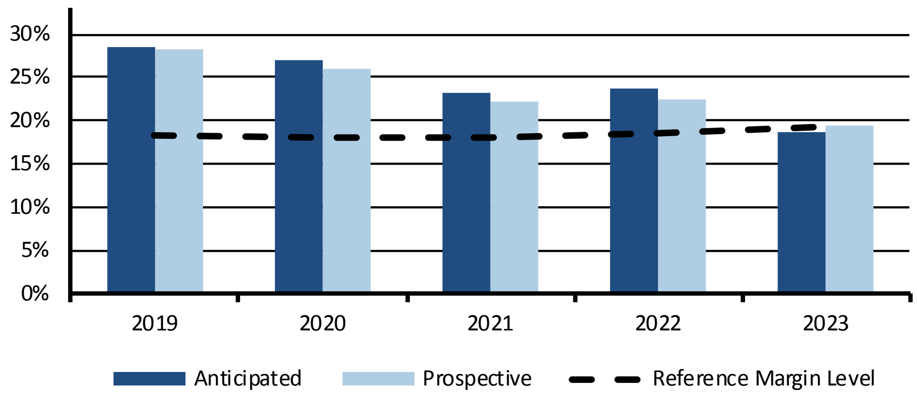


Figure 1.5: Ontario 5-year Projected Reserve Margins through 2023 (Anticipated and Prospective Reserve Margins)

How NERC Defines Future Capacity Supply

Tier 1: Unit that meets at least one of the following guidelines (with consideration for an area's planning processes):

- Construction complete (not in commercial operation)
- Under construction
- Signed/approved Interconnection Service Agreement (ISA)
- Signed/approved Power purchase agreement (PPA) has been approved
- Signed/approved Interconnection Construction Service Agreement (CSA)
- Signed/approved Wholesale Market Participant Agreement (WMPA)
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)

Tier 2: Unit that meets at least one of the following guidelines (with consideration for an area's planning processes)2:

- Signed/approved Completion of a feasibility study
- Signed/approved Completion of a system impact study
- Signed/approved Completion of a facilities study
- Requested Interconnection Service Agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)

Tier 3: Units in an interconnection queue that do not meet the Tier 2 requirement

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment (ProbA): Biannually, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment.

Loss of Load Hours: Loss of load hours (LOLH) is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period (or the load duration curve).

LOLH should be evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study horizons. LOLH does not inform of the magnitude or the frequency of loss of load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs, which can be modeled as resources with specific contract limits including hours per year, days per week, and hours per day constraints,
- EE programs, which can be modeled as reductions to load with an hourly load shape impact
- Distributed resources, such as behind the meter PV, which can be modeled as reductions to load with an hourly load shape impact

Expected Unserved Energy: Expected unserved energy (EUE) is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs.

This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). NERC refers to this measure as EUE ppm. Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss of load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is very useful in estimating the size of loss of load events so the planners can estimate the cost and impact. EUE can be used as basis for reference reserve margin to determine capacity credits for variable energy resources. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, the Australian Energy Market Operator is responsible for planning using 0.002 percent EUE as their energy adequacy requirement in Australia.[1] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load loss reliability component.

[1] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

Probabilistic evaluations identify resource adequacy risks during nonpeak conditions in WECC-CAMX

The analytical processes used by resource planners range from relatively simple calculations of planning reserve margins to rigorous reliability simulations that calculate system LOLE or loss of load probability (LOLP) values.[13] The one-event-in-10-year (0.1 events per year) LOLE is produced from this type of probabilistic analysis. This planning criterion requires an electric system to maintain sufficient capacity such that system peak load is not likely to exceed available supply more than once in a 10-year period. Utilities, system operators, and regulators across North America rely on variations of the one-event-in-10 year criterion for ensuring and maintaining resource adequacy.[14]

Probabilistic Assessment Results Summary

As part of a biannual process, this *2018 LTRA* includes a probabilistic evaluation for each assessment area and calculates LOLH and EUE for the third and fifth years of the LTRA. This year's analysis calculates the probabilistic resource measures for 2020 and 2022.[15] A summary of the indices are shown in **Table 1.2** on the next page.

[13] A traditional planning criterion used by some resource planners or load-serving entities is maintaining system LOLE below one-day-in-10 years. LOLE is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand. This is the original metric that is calculated using only the peak load of the day (or the daily peak variation curve). However, this metric is not being reported as part of this assessment. Currently, some assessment areas also calculate the LOLE as the expected number of days per year when the available generation capacity is insufficient to serve the daily demand (instead of the daily peak load) at least once during that day.

[14] https://www.nerc.com/comm/PC/Documents/2.d_Probabilistic_Adequacy_and_Measures_Report_Final.pdf

[15] 2020* denotes the results from the 2016 ProbA's 2020 projection. The ProbA from the prior iteration is used for comparison because the first year (in this case 2020) is the same study year in both the prior and current ProbA.

Table 1.2: 2020 and 2022 Projected Peak Reserve Margins and Probabilistic Indices by Assessment Area																		
	Reserve Margin (%)									Annual Probabilistic Indices								
Assessment Area	LTRA Anticipated			LTRA Reference			ProbA Forecast Operable			EUE (MWh)			EUE (ppm)			LOLH (hours/year)		
Year	2020*	2020	2022	2020*	2020	2022	2020*	2020	2022	2020*	2020	2022	2020*	2020	2022	2020*	2020	2022
WECC-NWPP-US	30.3%	25.9%	22.8%	16.3%	19.7%	19.6%	28.1%	16.1%	15.9%	0.00	1,896	2,553	0.00	6.45	8.58	0.00	0.47	0.58
MRO-SaskPower	25.6%	20.1%	17.7%	11.0%	11.0%	11.0%	22.6%	15.7%	11.7%	65.50	1,148	4,495	2.56	43	167	0.84	11.45	39.02
WECC-CAMX	21.3%	30.6%	23.6%	16.2%	12.3%	12.1%	25.4%	19.5%	22.8%	0.00	2,783	41,468	0.00	10.40	153.80	0.00	0.13	2.30
MRO-Manitoba	18.7%	22.1%	31.6%	12.0%	12.0%	12.0%	20.4%	14.7%	31.0%	0.24	3,259	0.00	0.01	0.12	0.00	0.00	2.39	0.00
TexasRE-ERCOT	20.8%	12.7%	10.6%	13.8%	13.8%	13.8%	11.4%	6.2%	4.6%	0.40	599	1,089	0.00	1.53	2.64	0.00	0.50	0.87
MISO	16.6%	21.7%	18.9%	15.2%	17.1%	17.1%	10.6%	14.2%	13.7%	95.80	14.20	31.60	0.13	0.02	0.04	0.13	0.11	0.21
NPCC-New England	18.2%	29.9%	28.5%	15.9%	17.2%	16.4%	9.4%	20.7%	19.0%	140.80	12.53	2.71	0.98	0.10	0.02	0.19	0.03	0.01
NPCC-New York	26.3%	24.1%	22.5%	15.0%	15.0%	15.0%	18.8%	15.3%	13.7%	2.06	0.07	0.03	0.01	0.00	0.00	0.00	0.00	0.00
FRCC	24.4%	23.7%	24.4%	15.0%	15.0%	15.0%	19.4%	19.1%	20.2%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPCC-Maritimes	24.4%	23.5%	25.4%	20.0%	20.0%	20.0%	18.1%	33.0%	33.5%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPCC-Ontario	25.1%	27.1%	23.6%	17.7%	18.0%	19.0%	11.9%	10.5%	11.5%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPCC-Québec	15.8%	16.4%	13.6%	12.7%	12.6%	12.6%	14.2%	9.5%	7.1%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PJM	28.5%	35.5%	35.2%	16.5%	15.9%	15.8%	16.1%	22.7%	22.5%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SERC-E	16.1%	21.1%	22.3%	15.0%	15.0%	15.0%	11.2%	20.2%	18.0%	49.39	0.00	0.00	0.22	0.00	0.00	0.05	0.00	0.00
SERC-N	18.6%	25.7%	25.2%	15.0%	15.0%	15.0%	18.0%	18.5%	17.7%	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SERC-SE	33.4%	31.3%	32.4%	15.0%	13.2%	14.4%	26.5%	23.6%	24.7%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SPP	22.7%	30.4%	27.2%	12.0%	12.0%	12.0%	15.0%	20.7%	17.1%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WECC-AB	29.6%	25.9%	23.4%	11.0%	10.4%	10.2%	26.8%	23.2%	19.9%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WECC-BC	12.4%	18.8%	15.9%	12.1%	10.4%	10.2%	17.3%	20.4%	22.2%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WECC-RMRG	21.7%	26.6%	23.5%	14.1%	16.8%	16.4%	24.6%	20.8%	18.5%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WECC-SRSG	21.2%	29.4%	24.0%	15.8%	15.1%	14.6%	29.0%	20.1%	16.7%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure 1.6 shows the 2022 projected peak reserve margins compared to the LOLH index.

In its probabilistic analysis, WECC projected that the reserve margin for the WECC-CAMX Region are over 22 percent in 2020 and 21 percent in 2022; however, due in part to the changing resource mix, LOLH is projected to increase from 0.13 hours in 2020 to 2.3 hours in 2022. A summary of the indices for WECC-CAMX are shown in **Table 1.3**. Additionally, the EUE for both years increased with nearly 2,800 MWh projected for 2020 and over 41,000 MWh projected for 2022.

The finding provides evidence that the planning reserve margin metric in areas with higher penetrations of resources with energy limitations and uncertainty (i.e., wind, solar, natural gas, hydro) may not be a completely accurate way to measure an area's resource adequacy during all hours of the year. Namely, energy limitations can exist, requiring more advanced stochastic analysis methods to identify risks to reliability.

Table 1.3: Probabilistic Base Case Summary Results for WECC-CAMX

Reserve Margin %			
	2020*	2020	2022
Anticipated	21.3%	22.2%	21.3%
Reference	16.2%	12.3%	12.1%
ProbA Forecast Operable	21.3%	19.5%	22.8%
Annual Probabilistic Indices			
	2020*	2020	2022
EUE (MWh)	0.00	2,783	41,468
EUE (ppm)	0.00	10.4	153.8
LOLH (hours/year)	0.00	0.13	2.3

*2016 Probabilistic Assessment

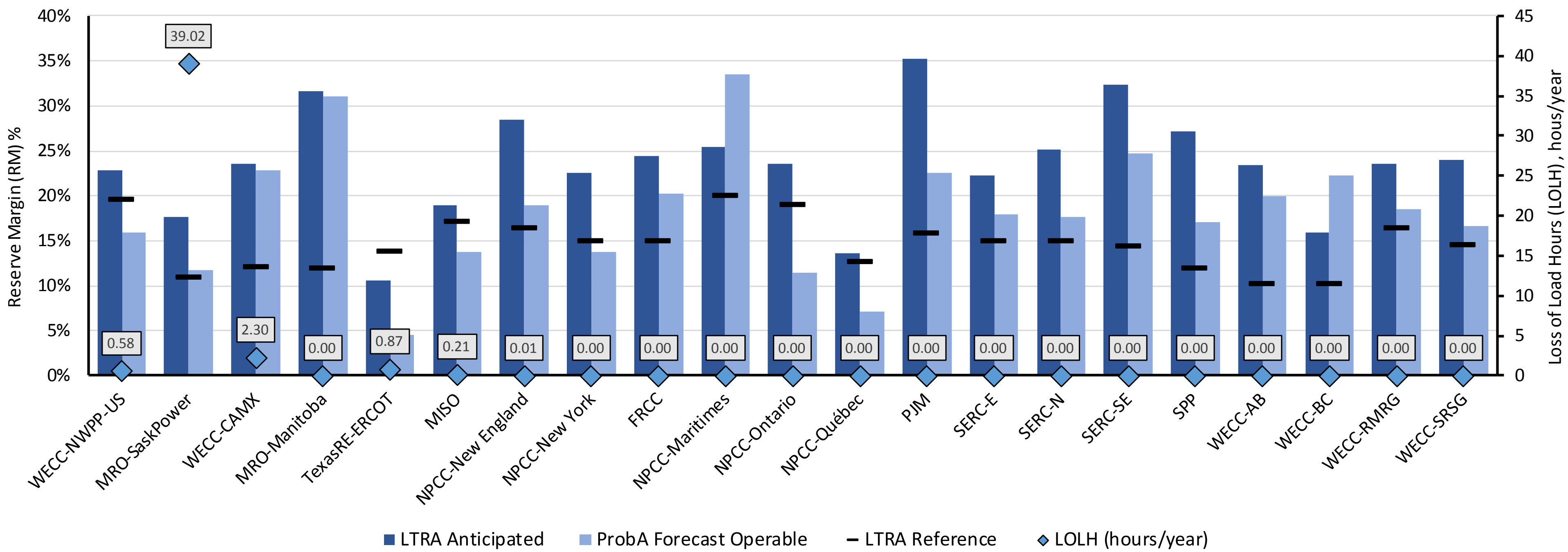


Figure 1.6: 2022 Assessment Area Reserve Margins and Loss of Load Hours (LOLH)

In **Figure 1.7**, a comparison of LOLH is provided that helps identify emerging risk that may not have been identified as a risk in 2016 when the last study was complete. A notable increase in the LOLH index is observed in WECC-NWPP-US, MRO-SaskPower, MRO-Manitoba, WECC-CAMX, and TRE-ERCOT.

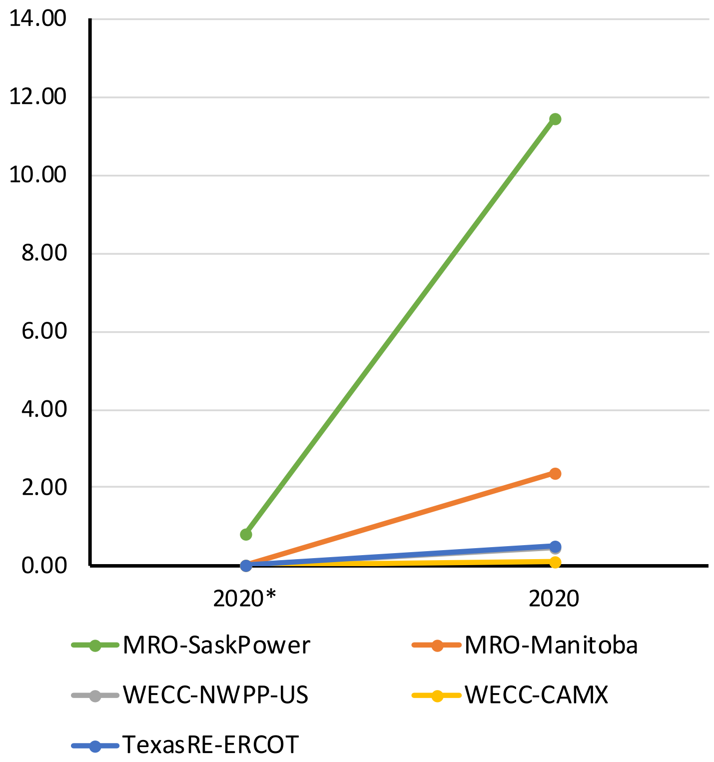


Figure 1.7: Comparison of the 2016 versus the 2018 Probabilistic Analysis, LOLH Notable Trends for the 2020 Study Year

Key Finding 2: Reliance on Natural Gas Generation Increases in some Areas with Continuing Resource Mix Changes

Key Points:

- North America has a diverse fuel mix; however, in some Regions an increasing reliance on natural gas can expose the BPS to fuel supply and delivery vulnerabilities, particularly during extreme weather conditions.
- Over the past decade, natural gas has been the fuel of choice for the majority of new generating capacity additions, particularly for generators designed to provide peaking capability and flexibility to help offset variable energy production
- Fuel assurance mechanisms offer important reliability benefits, particularly in areas with high levels of natural-gas-fired generation and constrained natural gas transportation. Recent market enhancements, such as capacity performance and pay-for-performance, offer mechanisms to positively improve generator availability.

Fuel Mix Changes

Figure 1.8 identifies the components of the fuel mix for the United States and Canada as a whole. Natural gas capacity continues to increase in many parts of the countries, and from a North American perspective, it increases from 43 percent to 46 percent by 2028. Coal and nuclear are projected to decrease to 19 and nine percent, respectively.

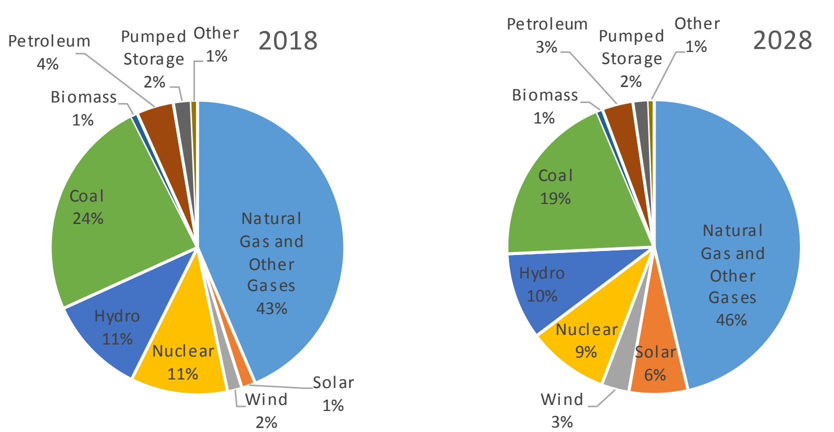


Figure 1.8: 2018 On-Peak Fuel Mix Compared to 2028 On-Peak Fuel Mix

Across North America, natural-gas-fired generation continues to increase beyond projections. From the 2009 through the *2018 Long-Term Reliability Assessment*, actual natural gas additions have outpaced projections; and over the next 10 years, 41 GW of Tier 1 resources are expected—this number expands to 96 GW when considering Tier 2 resources (**Figures 1.9** and **1.10**).

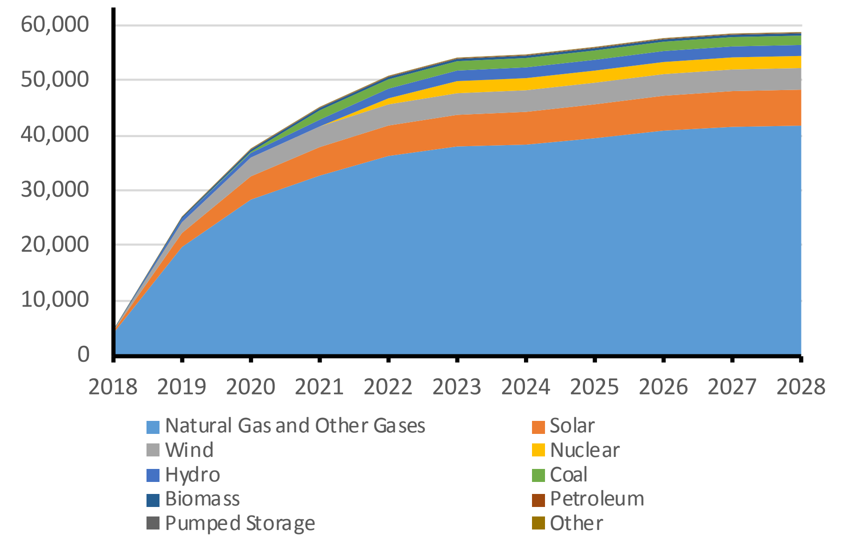


Figure 1.9: Tier 1 Planned Resources Projected Through 2028

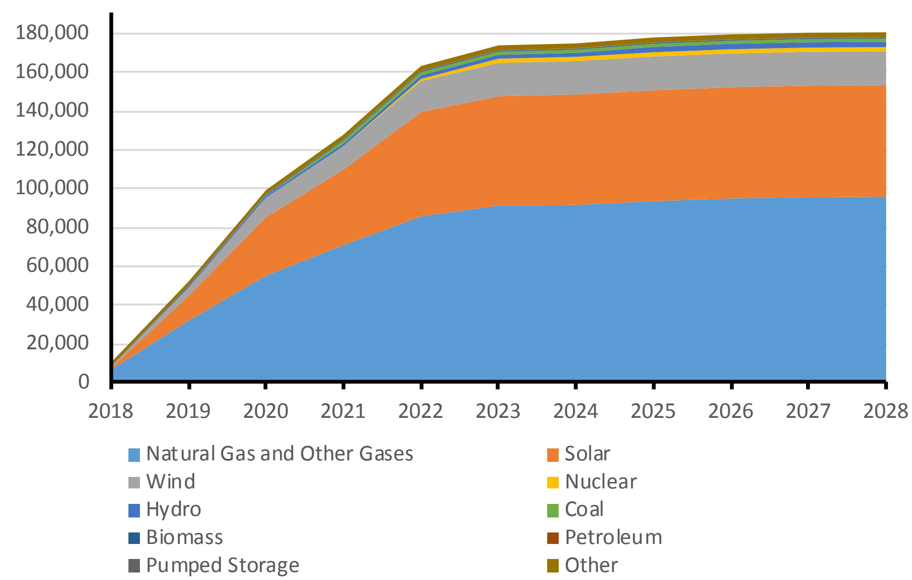


Figure 1.10: Tier 1 and 2 Planned Resources Projected Through 2028

NERC Capacity Supply Categories:

Future capacity additions are reported in three categories:

Tier 1: included in the Anticipated Resources category—planned generating unit or plant that meets at least one of the following requirements:

- Construction complete (not in commercial operation)
- Under construction
- Signed/approved Interconnection service agreement
- Signed/approved power purchase agreement
- Signed/approved Interconnection construction service agreement
- Signed/approved wholesale market participant agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to vertically integrated entities)

Tier 2: included in the Prospective Resources category—planned generating unit or plant that meets at least one of the following requirements:

- Signed/approved completion of a feasibility study
- Signed/approved completion of a system impact study
- Signed/approved completion of a facilities study
- Requested Interconnection service agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to RTOs/ISOs)

Tier 3: other planned generating units or plants that do not meet any Tier 2 requirements.

In addition to natural-gas-fired generation, solar additions provide the second most additions to capacity to the overall North American fuel mix with approximately seven GW of Tier 1 capacity **(Figure 1.9)**. When considering Tier 2 resources, up to 63 GW are projected **(Figure 1.10)**. These projections are used for peak reserve margin purposes and are different than the solar resource nameplate capacity.[16]

A significant amount of wind is also expected; however, because its peak contribution is relatively low, **Figures 1.9**, **1.10**, and **1.11** show that wind does not significantly contribute to peak capacity. While up to 82 GW of nameplate Tier 1 and 2 wind are expected by 2028, only about 20 GW is expected to contribute to peak capacity—about 25 percent.

While some areas of North America have and continue to see more rapid resource mix changes, as a whole North America has a diverse fuel mix and modest changes area currently planned over the 10-year period. A 10-year projection of North America peak capacity is shown in **Figure 1.11**.

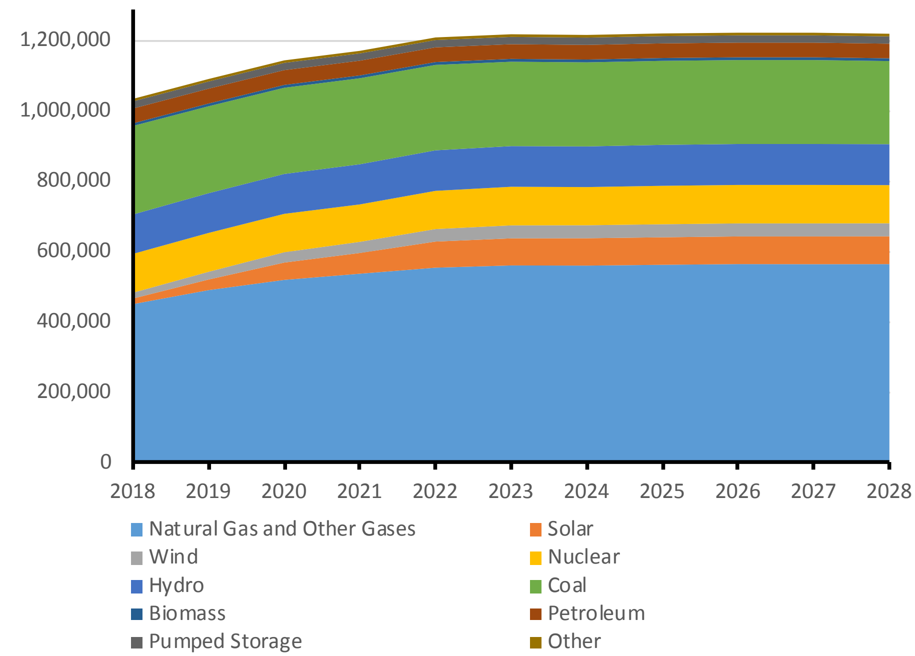


Figure 1.11: Existing, Tier 1, and 2 Planned Resources Projected Through 2028

[16] The nameplate capacity additions for 2028 are 11 GW of Tier 1 capacity and 86 GW of Tier 2 capacity.

Operating Reliability Risks Due to Conventional Generation Retirements: Capacity retirements located near metropolitan areas or large load centers that have limited transmission import capability present the greatest potential risk to reliability. Unless these retirements are replaced with plants in the same vicinity, these load centers will require increased power imports and dynamic reactive resource replacement.[1] If the transmission links between an area and generation sources are relatively weak, voltage instability can be the result. Dynamic reactive power must be provided to prevent voltage collapse. Solutions to preventing voltage instability could range from extensive transmission improvements to optimal placement of static var compensators, synchronous condensers, or locating new generation in the load pocket. Retiring generation units in a generation "pocket" might cause the remaining units to become a "reliability must run" units, which often require additional actions or investments (e.g., transformers, shunt capacitors) in equipment to maintain voltage stability.

1 Dynamic reactive support is measured as the difference between its present var output and its maximum var output. Dynamic reactive support is used to support system state transients occurring post-contingency. NERC's *Reactive Power Planning Reliability Guideline* provides strategies and recommended practices for reactive power planning and voltage control and accounts for operational aspects of maintaining reliable voltages and sufficient reactive power capability on the BPS:
https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability%20Guideline%20-%20Reactive%20Power%20Planning.pdf

Conventional Capacity Retirements

As shown in **Figure 1.12**, there have been approximately 39 GW of coal-fired, 13 GW of natural-gas-fired, and 1.1 GW of nuclear-powered capacity retired since 2013. Also shown are the announced retirements of approximately nine GW of coal-fired, seven GW of nuclear, and 10.9 GW of natural-gas-fired generation capacity.

Retirement plans have been announced for 14 nuclear units, totaling 7.1 GW. The fleet of 67 nuclear plants (118 units) in the United States and Canada meet over 20 percent and 16 percent of total electricity demand, respectively. Low natural gas prices continue to affect the competitiveness of nuclear generation and are a key contributing factor to nuclear generation's difficulty in remaining economically viable. See the following additional information:

- Seven plants have closed since 2012, including Gentilly (Québec), Crystal River (Florida), Kewaunee (Wisconsin), San Onofre (California), Vermont Yankee (Vermont), Oyster Creek (New Jersey), and Fort Calhoun (Nebraska).
- Owners of seven plants (14 units) have announced plans to retire within the next decade, including facilities in Ontario, California, New York, Pennsylvania, Michigan, and Massachusetts.

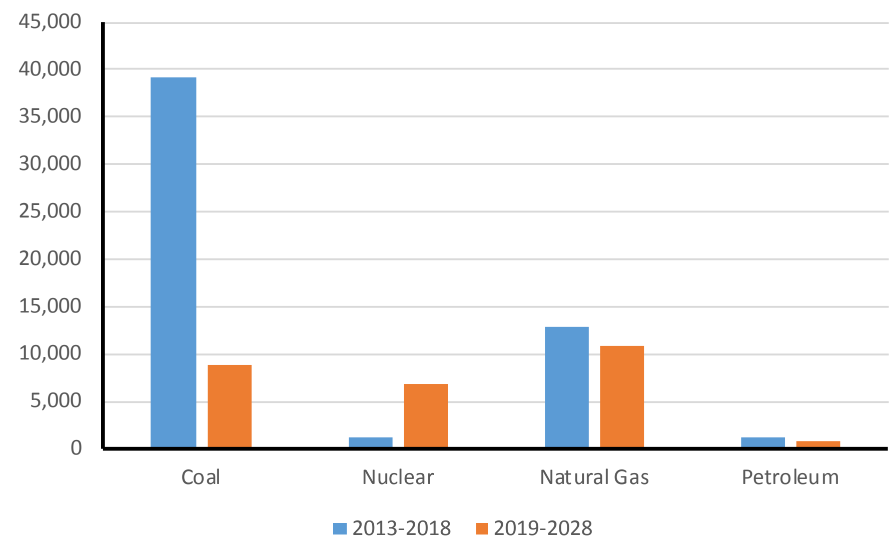


Figure 1.12: Capacity Retirements between 2013 and 2018, and 2019 Projected through 2028

- Legislation passed in Illinois created financial incentives through 2026 to support the continued operation of the Quad Cities and Clinton nuclear generation stations.
- The state of New York also enacted legislation establishing a zero-emission credit requirement for some upstate nuclear generating facilities.

Natural Gas Capacity Additions

NERC-wide natural-gas-fired on-peak generation has increased from 280 GW in 2009 to 460 GW today with an additional 41 GW planned during the next decade—96 GW when considering Tier 2 additions as shown in **Figure 1.13**.

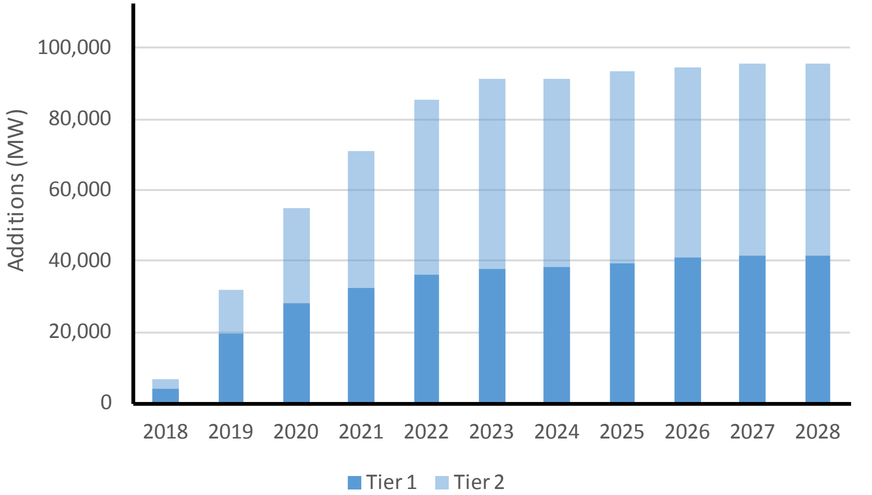


Figure 1.13: Annual Natural Gas Capacity Additions through 2028

During the past decade, several assessment areas have significantly increased dependence on natural-gas-fired generation, a trend that results from lower sustained natural gas prices, lower plant construction costs (compared to nuclear and coal), and environmental regulations that disadvantage coal plant investments. By 2023, FRCC, TRE-ERCOT, NPCC-New England, and most of the WECC assessment areas are expected to have at least 50 percent of their resources composed of natural-gas-fired generation with FRCC expected to near 80 percent as shown in **Table 1.4**. The notable increase of natural gas generation in these assessment area does not necessarily indicate an increased risk; however, it is an early warning indicator for planners who may need to review their supply, transportation, and back-up fuel sources for any emerging risk.

Table 1.4: Assessment Areas with more than 50 Percent Natural Gas as a Percent of Total Capacity

Assessment Area	2018 (MW)	2023 (MW)	2018 (%)	2023 (%)
FRCC	40,913	44,687	75.0%	77.2%
WECC-CAMX	41,352	36,966	62.0%	59.1%
TRE-ERCOT	49,435	52,449	65%	64%
NPCC-New England	15,712	16,261	51%	52%
WECC-SRSG	17,631	17,273	55.9%	55.6%
WECC-AB	7,682	7,682	50.8%	50.8%

As natural-gas-fired generation continues to increase, the electric industry needs to continue to evaluate and report on the potential BPS reliability effects of an increased reliance on natural gas. During extreme events, and most notably during the 2014 Polar Vortex, extended periods of cold temperatures caused direct impacts on fuel availability, especially for natural-gas-fired generation. Higher-than-expected forced outages and common-mode failures[17] were observed during the polar vortex due to the following:

- Natural gas interruptions, including supply injection, compressor outages, and one pipeline explosion
- Oil delivery problems
- Inability to procure natural gas
- Fuel oil gelling

Maintaining Fuel Diversity and Assurance

Replacing coal and nuclear generation with natural-gas-fired and variable generation introduces new considerations for reliability planning, such as ensuring there is adequate inertia, ramping capability, frequency response, and fuel assurance on the system. Diverse generation resources reduce risk from fuel supply disruptions (i.e., all of the "eggs" are not in one basket).

[17] 2014 Polar Vortex Review: https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

Fuel assurance mechanisms offer important reliability benefits, particularly in areas with high levels of natural gas and limited pipeline infrastructure. Fuel assurance, while not explicitly defined, refers to the confidence system planners have in a given resources' availability based on its fuel limitations. Table 1.5 identifies some of the mechanisms that can help promote fuel assurance as well as some of the questions BPS planners should be considering as the resource mix changes. In some areas, natural gas delivery pipelines were built and sized to serve customers of natural gas utilities—not specifically to serve electricity generators. Higher reliance on natural gas can lead to fuel-security issues, particularly during extreme cold weather periods when demand on the natural gas delivery system can be stressed, exposing electric generation to fuel supply and delivery vulnerabilities.

Table 1.5: Mechanisms and the Planning Considerations to Promote Fuel Assurance

Mechanisms Promoting Fuel Assurance	Planning Considerations
Fuel Service Agreements	What level of service does each generator maintain?
Alternative Fuel Capabilities	What are the fuel-firing capabilities of the unit? Is back-up oil maintained on-site? Is it tested?
Pipeline Connections	How many direct connections are available to the generator and are they served by different supply sources?
Market and Regulatory Rules	What rules are in place to promote generator availability? What tools exist to prepare and study large disruptions?
Vulnerability to Disruptions	What is the generation fleet's risk profile as it relates to reliance on natural gas storage and limited transportation sources?
Pipeline Expansions	Where growth in natural gas generation is occurring, is pipeline expansion also occurring?

As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electric reliability. Disruptions to the fuel delivery results from adverse events that may occur, such as line breaks, well freeze-offs, or storage facility outages. The pipeline system can be impacted by events that occur on the electric system (e.g., loss of electric motor-driven compressors), which is compounded when multiple plants are connected through the same pipeline or storage facility. Although the ability to use alternate fuel provides a key mitigation effect, only 27 percent of natural-gas-fired capacity added in the United States since 1997 is dual fuel capable.

With natural gas generation primed to continue its growth as the leading choice for new and replacement capacity, important distinctions around fuel assurance need to be incorporated into long-term planning. Mainly, natural gas generation is fueled using just-in-time transportation and delivery, and therefore, is subject to interruption and/or curtailment. In constrained natural gas markets, generation without firm supply and transportation are not expected to be served during peak pipeline conditions. Many of these plants no longer have the option of burning a liquid fuel. Further, regardless of fuel service arrangements, natural gas generation is subject to curtailment during a force majeure event. These fuel constraints need to be known by planners so they can better understand if there is insufficient energy available in a given system.

Regional Considerations

The electric industry is taking immediate steps to address concerns raised by NERC and other regulatory agencies including FERC, DOE, and individual state utility commissions. Because of both the geographic and regulatory differences across North America, it is important to evaluate how each area is addressing the challenges. Some areas, like Texas, have a significantly "meshed" natural gas pipeline system while others, such as California and New England, have limited access to the interstate pipeline system, storage, and production. Different regulatory structures give rise to different approaches. For instance, regulated states with integrated resource planning processes have the opportunity to incorporate firm pipeline transportation and back-up liquid fuel inventories into their cost-of-service rate structures. While in wholesale electricity markets, generally, generation owners determine their fuel supply arrangements and procure it based on economic risk. These regional perspectives are highlighted below along with the initiatives implemented to address natural fuel assurance risks:

FRCC

- Utilities maintain significant firm natural gas contracts and maintain dual fuel capability.
- Approximately 65 percent of the natural-gas-fired generation fleet can run on back-up fuel.
- Sabal Trail, the third major interstate natural gas pipeline, was added to increase delivery and supply diversity.

TRE-ERCOT

- ERCOT estimates that at least 34,706 MW of its natural-gas-fired fleet has firm natural gas contracts, representing about 58 percent of the fleet total. Using the responses received from the 2017 fuel survey, about 5,454 MW is dual-fuel capable. About 3,667 MW (six percent of the total) maintains at least one day of alternate fuel supply on-site during the winter season.
- Robust pipeline infrastructure significantly reduces risk.
- Recently instituted annual fuel survey of natural-gas-fired generation fleet to gauge alternate fuel capabilities.
- Improved coordination and information-sharing between generator owners and pipeline operators, which include receiving confidential notifications of operational issues occurring on the pipelines at the same time generators are notified.

WECC

- Improved information sharing between generator owners and pipeline operators with active coordination on energy emergencies with the California Energy Commission in response to the Aliso Canyon natural gas storage facility imposed limitations.
- A recent analysis by WECC[18] indicates the configuration of the natural gas–electric system, combined with the potential retirement of Aliso Canyon, creates region-wide reliability issues; this can cause widespread loss of electric load with the Southwest and Southern California areas due to being most vulnerable to major disruption events because of heavy reliance on natural gas generation to meet peak demands and limited natural gas storage capability. Specifically, the configuration of the natural gas–electric system, combined with the potential closure of Aliso Canyon, creates region-wide reliability issues concentrated in Southern California and the greater Phoenix area. Disruption scenarios involving a Desert Southwest pipeline rupture or Permian/San Juan Basin supply freeze-offs routinely result in unserved energy and/or unmet spinning reserves. WECC's analysis also finds that both the modeling scenarios and recent real-world events point towards a system being pushed to its limit, indicating that the Western Interconnection is at an important crossroads.

NPCC-New England

- Only three natural gas plants hold firm mainline transportation contracts that can fuel only one-third to two-thirds of their overall capacity. Only 11 natural-gas-capable plants (natural-gas-only or dual-fuel) hold lateral-only firm transportation contracts.
- The rest of the fleet relies on spot market natural gas supply and unused transportation to fulfill their daily electric commitments.

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[18] https://www.wecc.biz/Administrative/WECC%20Natural gas-Electric%20Study%20Public%20Report.pdf

- Preseason fuel inventory surveys for oil and dual fuel units[19] with market rules to offer flexibility and adjustments to the day-ahead energy market. A total of 43 units/stations are natural gas only single fuel source, totaling 10,427 MW winter capacity rating. A total of 61 units/stations are dual fuel capability totaling 9,544 MW winter capacity rating. These units are traditionally peaking units that primarily have a one to three day holding tank for oil storage, and the majority are refueled via trucking.
- Beginning in 2018, the pay-for-performance (PFP) program will provide incentives for units to perform during extreme conditions.
- Winter reliability program incentivizes dual-fuel units, securing fuel inventory, and testing fuel-switching capability.[20]

- Improved coordination and information sharing between ISO-NE and operators (including maintenance schedules) and a natural gas usage tool that allows system operators to estimate spare natural gas pipeline capacity (by individual pipe).
- Mystic Station (2,274 MW) retirement request further strains winter season reliability. Because the power plant does not rely on natural gas from the interstate pipeline, it is not impacted by interruptions or curtailments from the pipeline network. However, ISO-NE analysis identifies unacceptable fuel security risks and could cause the system operator to deplete 10-minute operating reserves (a violation of NERC Reliability Standard) on numerous occasions and to possibly trigger load shedding (or rolling blackouts) during the winters of 2022–2023 and 2023–2024.[21]

  The future of Mystic Station remains uncertain as a FERC decision rejected an ISO-NE proposal that requested cost recovery. To address the energy security concern, which could be exacerbated with the Mystic Station retirement request, ISO New England has commenced efforts to develop system operations and market design solutions to be accomplished by mid-2019. This effort responds to a FERC order directing ISO New England to develop and file with the commission improvements to its market design to better address regional fuel security issues by July 1, 2019."[22]

[19] A total of 30 percent of natural-gas-fired fleet is capable of using alternative fuel.

[20] The Winter Reliability Program ends after the 2017–18 winter.

[21] Compounding these issues, the retirement of Mystic Station not only would deprive the New England's BPS of winter generating capacity with what is considered "on-site" fuel, but it also would mean the loss of the Distrigas' biggest LNG customer. ISO-NE procured independent consultation to assess this situation; they found that these actions would substantially diminishing Distrinatural gas's financial viability. See Testimony of Richard L. Levitan and Sara Wilmer at 7:5–8, 19–22:2 (stating that retirement of Mystic 8 and 9 likely would be the start of a "death spiral" for Distrinatural gas because its other business is insufficient to enable it to recover its estimated going-forward costs) ("Levitan/Wilmer Testimony").

[22] https://www.ferc.gov/CalendarFiles/20180702193957-ER18-1509-000.pdf

NPCC-New York

- Increased coordination in operator control room, including a visualization of the Northeast interstate pipeline system highlighted to show when operational flow orders are posted.
- A weekly web-based fuel survey "portal" provides generator fuel information to the operators.
- A communications protocol is in place with New York to improve the speed and efficiency of generator requests to state agencies for emissions waivers if needed for reliability.
- Weekly and daily dashboards are developed during cold weather conditions that indicate fuel and capacity margin status.
- An emergency communication protocol is in place to communicate electric reliability concerns related to fuel availability to pipelines and natural gas LDCs during tight electric operating conditions.

PJM

- Capacity performance rules, incentives, and charges for nonperformance are in place to promote adequate generator availability during peak days.
- Better performance observed in the early 2018 cold snap and in the 2014 Polar Vortex.[23] Positive indicators of the effectiveness of capacity performance include a decrease in restrictive generator operating parameters, reported investment in major reliability work for existing resources, and new resources investing in firm natural gas and transportation contracts.

SERC

- Entities procure firm transportation on various natural gas pipelines and natural gas supply from various natural gas supply basins to ensure reliable system operations for natural-gas-fired plants. Some companies report procuring firm natural gas storage capacity with various natural gas storage providers with access to multiple pipelines to protect against supply disruptions.
- For entities in SERC SE, firm transportation, firm natural gas storage, and fuel oil backup provide for reliable operations and protection from natural gas supply and transportation issues.

[23] https://www.pjm.com/-/media/library/reports-notices/capacity-performance/20180620-capacity-performance-analysis.ashx?la=en

The Stagnation of Pipeline Expansion into New England

Although natural gas production from the Marcellus/Utica basins is projected to increase, New England currently cannot access the full benefits of that natural gas production. Only two minor natural gas pipeline expansion projects were fully put into service: Spectra Energy's Algonquin Incremental Market (AIM) project (Winter 2016/17) and Tennessee Natural gas Pipeline's (TGPs) Connecticut Expansion Project (Winter 2017/18), totaling an incremental 414,000 dekatherms per day of new pipeline capacity.

Enbridge's Atlantic Bridge Project is designed to provide an additional 132,700 Dth/d capacity on its Algonquin Natural gas Transmission (AGT) and Maritimes & Northeast (M&N) pipeline systems to move natural gas into New England and to specific end use markets in the Canadian Maritime provinces; the initial in-service date was November 2017. The new facilities in Connecticut enable AGT to provide firm transportation service for a portion of the Atlantic Bridge's project capacity. However, substantial community push-back has taken place over the proposed new compressor station located in Weymouth, Massachusetts (Fore River); the state of Massachusetts has not issued the necessary air permits for the new compressor project. Since some of the project work has been completed, on October 27, 2017, the FERC granted AGT's request to place the Connecticut facilities into service to provide 40,000 Dth/d day of incremental firm transportation service. The projected in-service dates for the Weymouth compressor is prior to Winter 2018/19 operations.

However, these minor expansion projects and their benefits will be more than offset by the recent retirement of Vermont Yankee nuclear power station (620 MW) as well as the retirement of Brayton Point (~1,500 MW of coal, natural gas, and oil) and the expected retirement of the Pilgrim Nuclear Station (677 MW) in 2019. It is safe to say that, although there have been several past proposals to build new greenfield natural gas pipelines into New England, the combination of local, town, city, and state opposition within both New York and New England has effectively canceled all major pipeline expansion proposals for New England. Several natural gas transportation companies have even halted their business development activities in New England.

One of the improvements to ISO-NE's Forward Capacity Market rules is PFP, which went into effect on June 1, 2018. PFP will create stronger financial incentives for generators to perform when called upon during periods of system stress; a resource that underperforms will effectively forfeit some or all capacity payments, and resources that perform in its place will get the payment instead.[1] PFP will also create incentives to make investments to increase unit availability, such as implementing dual-fuel capability, entering into firm natural gas supply contracts, and investing in new fast-responding assets. By creating financial incentives for generators to firm up their fuel supply, PFP may indirectly provide incentives for the development of on-site CNG, liquid natural gas (LNG), and/or fuel oil storage, or expanded natural gas pipeline infrastructure with dedicated firm contracts within the power sector. However, PFP will not reach full effectiveness until the seven-year phase-in of the new performance rate is complete. Until that time, the Region may be challenged to meet power demand at times when regional natural gas pipeline capacity is being contractually utilized. Conversely, however, the new PFP market rules may hasten the retirement of older, inefficient resources with poor historical performance and heat rates and initiate the entrance of new, efficient, better-performing resources, which hopefully will be dual-fuel-peaking resources (natural gas/oil).

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[1] Under the PFP, all resources with a capacity obligation can be penalized $2,000/MWh for failing to supply energy or reserves when capacity becomes scarce while resources that over-perform relative to their obligation (including those with no obligation) can receive $2,000/MWh of additional revenue. This performance payment rate is scheduled to increase to $5,455/MWh over the coming six years.

Key Finding 3: Frequency Response Is Expected to Remain Adequate Through 2022

Key Points:

- Despite increasing amounts of asynchronous resources and decreasing inertia from generation, each of the four Interconnections expect to have adequate and diverse sources of frequency response, and all have a low likelihood of activating under-frequency load shedding (UFLS) schemes.
- In February of 2018, FERC Order No. 842[24] was issued and mandates all new generating facilities to maintain the capability of providing primary frequency response. While FERC Order No. 842 does not require certain performance of providing frequency response in real-time, it does provide clear direction and assurances that all generation resources connected to the BPS have the capability of providing it.
- Maintaining Interconnection frequency within acceptable boundaries following the sudden loss of generation or load can be accomplished using control functions of inverters, which includes energy storage, and load-shedding relays; this is generally known as fast frequency response (FFR). The application of FFR is expected to continue and support frequency when synchronous inertia is insufficient.
- It is not necessary to monitor Quebec Interconnection frequency response in NERC's future assessment activities due to the operational controls in place as well as the lack of projected resource mix changes over the next 10 years.
- Future changes to the resource mix (e.g., accelerated generation retirements, economics) will impact the results of this analysis and NERC's assessment.

Background: How Does Inertia and Frequency Response Support Reliability?
Frequency support is the response of generators and loads to maintain the system frequency in the event of a system disturbance. Frequency support is provided through the combined interactions of synchronous inertia (traditionally from generators such as natural gas, coal, and nuclear plants as well as from motors at customer locations) and frequency response (from a wide variety of generators and loads). Working in a coordinated way, these characteristics arrest and eventually stabilize frequency. An illustrative example of this behavior is shown in **Figure 1.14**. A critical issue is to stabilize the frequency before it falls below UFLS values or rises above over-frequency relay trip settings.[25]

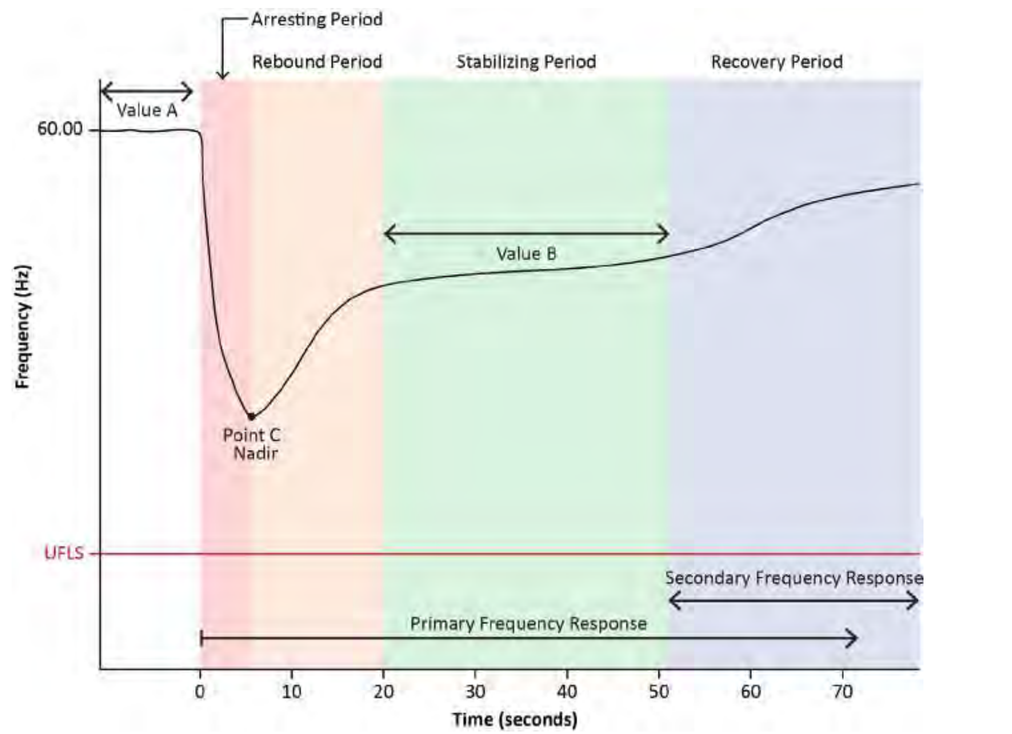

Figure 1.14: Illustrative Example of Inertial and Frequency Response Behavior after a Disturbance

[24] FERC Order No. 842 issued February 15, 2018

[25] NERC-developed instructional videos: *The Basics of Essential Reliability Services*, https://vimeopro.com/nerclearning/erstf-1

Inertia and frequency response are properties of the Interconnection (not to each balancing area individually) and these properties have different characteristics for each Interconnection. For example, if changes to the resource mix alter the relative amounts of synchronous inertial response (SIR) or frequency response, various mitigation actions are possible (such as obtaining faster primary frequency response from other generators or loads) to maintain or improve overall frequency support.

Synchronous inertia is the measure of stored kinetic energy in a rotating generator or machine. Synchronous inertia is a constant, and it is a function of the MVA[26] size and the physical attributes of the generator's rotating mass. During a disturbance, the stored kinetic energy of the resource is injected into the system (SIR) and assists in reducing the rate of change of frequency (RoCoF) and the depth of the frequency decline. Therefore, the Interconnection inertia is a function of the generation resource mix, the amount of load being served, and the time of day.

Reliability Challenges

Asynchronous resources—generators that do not use mechanical rotors that synchronize with system frequency to produce electricity, such as wind, solar, or any other resource that uses inverter technology—cannot directly provide synchronous inertia. However, wind resources, for example, equipped with specific controls can emulate inertia for a limited period of time by extracting stored energy from the rotating wind turbine and increasing the real power output (MW) of the wind turbine. The additional MW injection delivered to the grid during the loss of a system resource will reduce the RoCoF and the depth of the frequency decline; this provides enough time for the primary frequency response to aid in the frequency recovery of the interconnection. This form of frequency-arresting power is commonly referred to as FFR. The concept also applies to solar and energy storage systems connected asynchronously when "headroom"[27] is maintained as part of the dispatch. Like wind resources, storage systems can be used to inject MW during a disturbance to reduce the RoCoF and arrest the decline in the system's frequency.

The Four Factors that Determine Reliable Interconnection Response:[1]

- The size of the resource-loss event
- The Interconnection inertia at the time of the event, which determines the rate of frequency decline
- The speed with which other on-line generators or resources respond to arrest and stabilize frequency (primary frequency response)
- The means by which other generators or resources respond subsequently to restore frequency to its original scheduled value and to restore reserves to their original state of readiness (i.e., secondary and tertiary frequency control)

The four factors stated above identify the variables that help assess an Interconnection's frequency response. Synchronized turbine generator automatic control systems (governors) can sense the decline in frequency and control the generator to increase the amount of energy injected into the interconnection.

Frequency will continue to decline until the amount of energy is rebalanced through the automatic control actions of primary frequency response resources and reduction of system load due to its sensitivity to frequency. Greater inertia reduces the RoCoF, giving more time for governors to respond. Conversely, lower inertia increases the reliability value of faster-acting frequency control resources in reducing the severity of frequency excursions.

[1] Adapted from Frequency Control Requirements for Reliable Interconnection Frequency Response, FERC/LBNL: https://www.ferc.gov/industries/electric/indus-act/reliability/frequency-control-requirements/report.pdf

[26] MVA: [Mega] volt ampere is the unit used for the apparent power in an electrical circuit, equal to the product of root-mean-square (RMS) voltage and RMS current. With a purely resistive load, the apparent power is equal to the real power. Where a reactive (capacitive or inductive) component is present in the load, the apparent power is greater than the real power as voltage and current are no longer in phase. In the limiting case of a purely reactive load, current is drawn but no power is dissipated in the load.

[27] This is the difference between the current operating point of a generator or transmission system and its maximum operating capability. The headroom available at a generator establishes the maximum amount of power that generator theoretically could deliver to oppose a decline in frequency. However, the droop setting for the turbine-governor and the highest set point for UFLS will determine what portion of the available headroom will be able to deliver to contribute to primary frequency control.

In past reliability assessments, NERC had noted concerns related to the potential reductions in the supply of frequency response capability due to the ongoing retirements of synchronous generation and the significant addition of variable energy resources. However, in February 2018, FERC issued Order No. 842[28] mandating all new generating facilities to maintain primary frequency response capability. While FERC Order No. 842 does not require certain performance of providing frequency response in real-time, it does provide clear direction and assurances that all generation resources connected to the BPS should be capable of providing it.

Frequency Response and Inertia Measures

Trends in the frequency measures can be analyzed using historical data and projected into the future using reasonable planning assumptions and models. The NERC PC and Operating Committee (OC) jointly created the Essential Reliability Services Task Force (ERSTF) in 2014 to consider reliability issues that may result from the changing generation resource mix. In 2015, the ERSTF proposed measures for ERS for examination and potential ongoing monitoring to identify trends. The frequency measures are intended to help monitor and identify trends in frequency response performance as the generation mix continues to change.

The holistic frequency measure, called Measure 4 in ERSWG reports, tracks phases of frequency performance for actual disturbance events in each Interconnection (e.g., initial frequency rate of change and timing of the arresting and recovery phases). Other measures look at components of this coordinated frequency response, such as the amount of SIR (Measure 1), and the initial rate of change in frequency following the largest contingency event (RoCoF, Measure 2). These measures are further described in **Table 1.6**.

The current resource contingency criteria (RCC) for each Interconnection is provided in **Table 1.7** on the next page. The values defined correspond to select contingencies used for BAL-003-1.1 requirements and interconnection frequency response obligations. If operating restrictions would limit the RCC, then that will be accounted for as part of the case creation and contingency definition. For example, Hydro Québec limits generation dispatch for low inertia conditions such that 1,700 MW RCC cannot occur; this mitigates a potential severe contingency where inertial conditions are of concern.

Table 1.6: Measures of Frequency Response

Measure	What it Measures	Summary Assessment Findings
SIR (Measure 1)	The minimum inertial response amount (total stored kinetic energy) projected in each Interconnection	Despite the retirement of nearly 80 GW of conventional synchronous generation over the past eight years, there appears to be more than sufficient inertia within all Interconnections. ERCOT's use of load response to respond to frequency disruptions is effective in supporting low-inertia conditions.
RoCoF (Measure 2)	The calculated rate of frequency decline within the first 0.5 seconds following the largest credible contingency	No negative trends identified. ERCOT studies show that load response is extremely effective in arresting frequency due to its ability to perform very quickly.
Frequency Response Performance (Measure 4)	Simulated dynamic behavior of an Interconnection's response to the largest credible contingency	Simulations in both Eastern and Western Interconnection show sufficient frequency response in future planning cases.

[28] FERC Order No. 842 issued February 15, 2018

Table 1.7: RCC and UFLS Tripping Set-Points by Interconnection

Eastern Interconnection	Western Interconnection	Texas Interconnection	Quebec Interconnection
4,500 MW	2,740 MW	2,750 MW	1,700 MW
59.5 Hz	59.5 Hz	59.3 Hz	58.5 Hz

Trends and Projected Interconnection Performance

A summary of each Interconnection's results for NERC's assessment is included in Table 1.8.[29] Despite increasing amounts of asynchronous resources and decreasing inertia from generation, each of the four Interconnections expect to have adequate and diverse sources of frequency response, and thus, all have a low likelihood of activating UFLS schemes. These results were confirmed by dynamic studies performed for both the Eastern and Western Interconnections and implemented operational procedures for Texas and Quebec Interconnections.

As the resource mix continues to evolve, so is the resulting Interconnection inertia. NERC and the Resources Subcommittee (RS) are working with the Interconnections to monitor their respective annual minimum SIR for trending. A summary of the historic SIR is provided for all Interconnections in Figure 1.15 on the next page. As observed over the past three years, there has not been a large change in minimum inertia levels and the demand level corresponding with it. More in-depth analysis can be found in NERC's *2018 State of Reliability* report.[30]

One approach in understanding the relationship between minimum SIR and minimum system load is to evaluate the ratio of the two values. There is no consistent critical value that can apply to all Interconnections to determine when reliability is in jeopardy; however, based on recent ERCOT analysis, a critical SIR of 100 GW-seconds has been established. Based on this, one can calculate the critical ratio of minimum system load to minimum SIR, which is approximately 30 percent for ERCOT, using 2018 minimum load value. The 30 percent value can be used as an initial screening to indicate the need for closer evaluation. Beyond this amount, faster frequency response may be needed beyond what is currently available from either non-synchronous sources or load shedding.[31]

Table 1.8: Summary Table of Results of NERC Frequency Response Sufficiency Assessment

Interconnection	Highest Non-Synchronous Penetration at Minimum Inertia	Number of Critical Inertia Conditions Reached?	Lowest Frequency Nadir Observed in Planning Studies	Likelihood of Credible Disturbance Resulting in UFLS Activation[1]
Eastern Interconnection	5%	0	59.85 Hz	Low
Western Interconnection	15%	0	59.84 Hz	Low
Texas Interconnection	54%	0	N/A	Low
Quebec Interconnection	18%	0	N/A	Low

Due to the smaller size, the Texas and Quebec Interconnections experience lower system inertia compared to Eastern and Western Interconnections. Currently, wind amounts to more than 17 percent of installed generation capacity in the Texas Interconnection and has served as much as 50 percent of system load during certain periods. In Quebec, hydro accounts for over 95 percent of the generation, which generally has lower inertia compared to synchronous generation of the same size (e.g. coal and combined cycle units). As a result, ERCOT and Québec have both established unique methods to ensure sufficient frequency performance.

[29] Likelihood of UFLS determined by the study results and assumptions. Low likelihood indicates that studies are being performed, the expected dynamic response of the system is generally known, and the simulated frequency nadir is above UFLS set-points. If simulated frequency nadir is less than UFLS set-points, then the likelihood is high. Medium likelihood is used to describe an Interconnection that is experiencing a significant shift in resources, may not have the market processes in place to ensure resource performance, and/or studies are not sufficiently representative of system behavior.

[30] NERC 2018 State of Reliability: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_2018_SOR_06202018_Final.pdf

[31] In ERCOT for example, in order to qualify, load response resources must perform within 0.5 seconds. If load is required to perform faster and/or at higher frequency triggers, more frequency arresting power can be made available to support lower levels of system inertia.

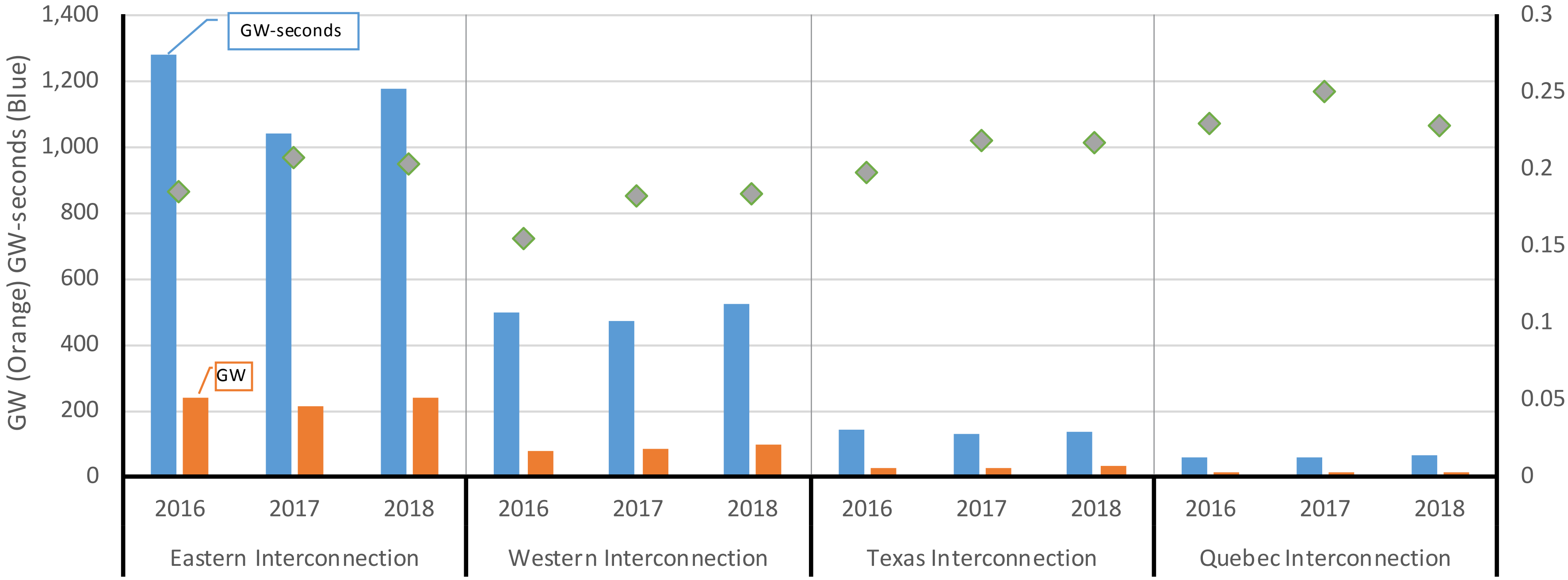

Figure 1.15: Historical Interconnection Minimum Synchronous Inertia (GW-seconds) by Year

In Texas[32] and Québec[33] Interconnections, critical inertial levels are credible within their projected dispatches, and therefore, operators have established operating procedures to manage real-time inertia in their respective systems. Because the two systems are relatively small compared to the Eastern and Western Interconnections, they are more likely to observe and have to manage minimum inertia conditions. While Quebec does not anticipate a significant resource mix change, Texas's resource mix continues to evolve and currently established operational procedures may need to be further adjusted.

Past performance identified in NERC's *2018 State of Reliability Report*[34] shows continued success in ERCOT in managing the increasing amounts of wind resources. One approach ERCOT has taken is to require wind generation to provide downward frequency response through curtailment action. As wind generation continues to increase in the Interconnection, extracting capabilities from asynchronous generation helps support the reliability needs of the BPS, and ERCOT has seen improved frequency performance with both the arresting and stabilizing periods over the last several years. Further, wind load is a positive and statistically significant factor that affects respective frequency response in ERCOT.

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[32] ERCOT procures RRS amounts based on the expected system inertia to ensure sufficient frequency response after a 2,750 MW loss. In 2015, ERCOT revised its ancillary service methodology and now determines the minimum RRS requirements based on anticipated system inertia conditions.

[33] Since 2006, Québec has applied a real-time control criteria, called the PPPC limit (MW), that actively restricts the maximum MW loss of generation following a single contingency event. System operators perform generation re-dispatch in real-time or increase the level of synchronous generation on-line to ensure the PPPC limit is not exceeded and adequate frequency performance is maintained.

[34] NERC 2018 State of Reliability Report: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_2018_SOR_06202018_Final.pdf

In 2018, ERCOT conducted and released a study[35] that analyzed the system-wide stability impacts for a scenario that included a high penetration of renewable generation. The study analyzed a full suite of stability and dynamics-related issues (beyond frequency response) within a scenario case, totaling 28,000 MW of renewable generation serving about 70 percent of the total system load. At this level of renewable penetration, ERCOT determined there would be significant stability issues that would need to be addressed to maintain a reliable grid.

An overview of analytical processes and methods used in forward looking assessment of four Interconnections are posted on the NERC website in a technical brief.[36]

[35] Dynamic Stability Assessment of High Penetration of Renewable Generation in the ERCOT Grid: http://www.ercot.com/content/wcm/lists/144927/Dynamic_Stability_Assessment_of_High_Penetration_of_Renewable_Generatio....pdf)

[36] Forward Looking Frequency Trends Technical Brief ERS Framework Measures 1, 2, and 4: Forward Looking Frequency Analysis: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERS_Forward_Measures_124_Tech_Brief_03292018_Final.pdf

Key Finding 4: Increasing Solar and Wind Resources Requires more Flexible Capacity to Support Ramp Requirements

Key Points:

- As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability—such as supporting solar down ramps when the sun goes down and complementing wind pattern changes.
- Increasing solar generation in California increases the need for flexible resources. CAISO's 2018 solar generation projection increases CAISO's three-hour ramp requirements to over 17,000 MW, approximately 20 percent greater than the amount projected for 2018.
- Changing ramping requirements induced by increasing amounts of wind is largely managed with improved forecasting. Ramp forecasts allow ERCOT operators to curtail wind production and/or reconfigure the system in response to large changes in wind output.

System Flexibility Needs

In order to maintain load-and-supply balance in real time with higher penetrations of variable supply and less-predictable demand, operators are seeing the need to have more system ramping capability. This can be accomplished by adding more flexible resources within their committed portfolios or by removing system constraints to flexibility. Flexible resources, as described in this section, refer to dispatchable conventional as well as dispatchable variable resources, energy storage devices, and dispatchable loads.

Ramping is related to frequency through balancing of generation and load during daily system operations. Changes in the amount of nondispatchable resources,[37] system constraints, load behaviors, and the generation mix can impact the needed ramp capability and amount of flexible resources[38] needed to keep the system balanced in real-time. For areas with an increasing penetration of nondispatchable resources, the consideration of system ramping capability is an important component of planning and operations.[39]

[37] A nondispatchable resource is defined to be any system resource that does not have active power management capability or does not respond to dispatch signals

[38] A flexible resource is defined to be any system resource that is available or can be called upon in a short time to respond to changing system conditions.

[39] 2015 ERSWG Measures Framework Report Final Version

System ramping capability with flexible resources is becoming an important component of planning and operations. For example, CAISO is experiencing challenges with net load[40] ramping and over-supply conditions. High penetrations of variable resources are meeting a large portion of their customers' energy needs during various times of the day, resulting in the need for additional flexibility and ramping capability from the rest of the generation fleet to respond to changes in output. An illustrative example of this is shown in **Figure 1.16** on the next page, which shows that as solar PV is added to a particular system increased ramping capability is needed to support the increased ramping requirements. This is not a completely new concern for operators as some resources and imports have a long history of nondispatchability due to physical or contractual limitations. However, variable resources (particularly solar generation due to its daily production patterns) are the primary driver leading to increased ramping requirements. Other dispatchable resources are needed in reserve to offset the lack of electricity production when variable fuels (e.g., sun, wind) are not available.

[40] Net Load = Load – Wind and Solar Power Production

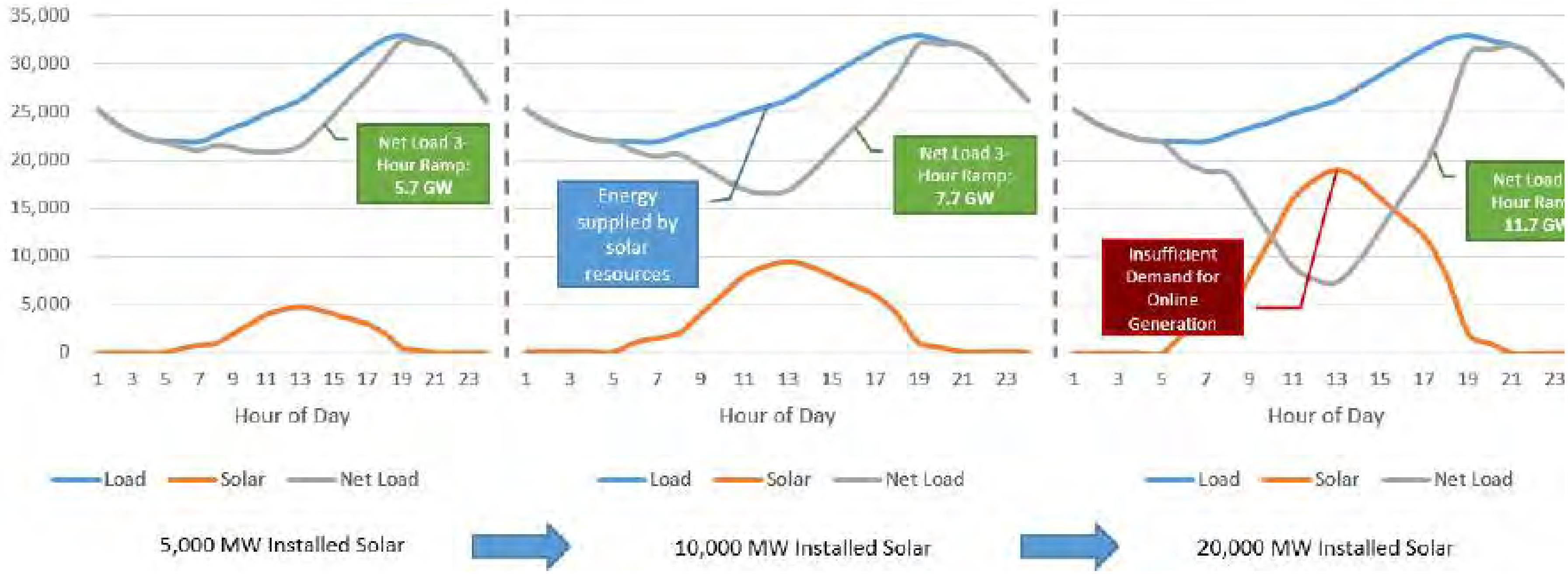


Figure 1.16: Example of Increasing Solar Resources Leading to Increased Ramping Requirements

Ramping is a term used to describe the loading or unloading of generation resources in an effort to balance total generation and load during daily system operations. Changes in the amount of nondispatchable resources, system constraints, load behaviors, and the generation mix can impact the needed ramp capability and amount of flexible resources needed to keep the system balanced in real-time. For areas with an increasing penetration of nondispatchable resources, the consideration of system ramping capability is an important component of planning and operations. Therefore, a measure to track and project the maximum one-hour and three-hour ramps for each assessment area can help understand how significant the need for flexible resources is.

For areas with high penetrations of nondispatchable resources, these resources are being dispatched at maximum power output in order to supply a large portion of system demand during various times of the day; as a result, there is a need for additional flexibility and ramping capability from the rest of the generation fleet. Ramping and flexible resource needs are difficult to predict as they are dependent on weather, the geographic uniformity of behind-the-meter PV resources, end-use electric consumer behavior, the generation resource mix, and generation dispatch availability. Because solar PV generally performs uniformly over a given area (the smaller the area the more uniform), as more solar PV generation built, the steeper the ramps the system operator will need to offset. Thus, increased ramping capability will be needed on the system from dispatchable and flexible resources.

Solar and Wind Capacity Additions

Table 1.9 identifies solar and wind capacity additions by assessment area. From a nameplate capacity perspective, 97 GW of solar and 110 GW of wind (Tier 1 and 2) are planned to be installed over the next ten years.

Ramping Capability Assessment

For the *2018 LTRA*, a detailed review of the CAISO and ERCOT areas was completed. Of all areas assessed, the RAS has identified ERCOT and CAISO projections of wind and solar as areas of interest regarding ramping challenges. In ERCOT, the concern is driven by significant wind while the drivers in CAISO are solar.

While these areas represent the systems most in need of flexibility, other systems will need to consider flexibility as part of their planning as penetration of wind and solar generating resources increase in those systems. One approach to system flexibility is to gain access to more resources and loads. CAISO's Western Energy Imbalance Market[41] has provided a mechanism to share resources and benefit from the load and renewable energy resource production diversity across the Western Interconnection. This has not only led to significant system cost savings as a result of sharing resources[42] but also reliability benefits, including improved reliability coordination, balancing and ramping, contingency response, and operational flexibility when managing extreme events.

Table 1.9: Solar and Wind Nameplate Capacity, Existing and Planned Additions through 2028

Assessment Area	Nameplate MW of Solar				Nameplate MW of Wind			
	Existing 2018	Tier 1 2028	Tier 2 2028	Total 2028	Existing 2018	Tier 1 2028	Tier 2 2028	Total 2028
ERCOT	1,482	2,141	19,401	23,024	21,207	10,599	20,959	52,765
FRCC	398	5,589	0	5,987	0	0	0	0
Manitoba	0	0	0	0	259	0	0	259
Maritimes	1	2	0	3	1,122	114	0	1,236
MISO	244	270	36,738	37,251	16,949	2,853	41,687	61,490
New England	939	90	114	1,142	1,371	33	3,316	4,721
New York	32	25	20	77	1,739	284	691	2,715
Ontario	380	83	0	463	4,412	535	0	4,947
PJM	1,356	2,213	21,106	24,675	7,632	2,876	12,670	23,178
Quebec	0	0	0	0	3,880	43	0	3,922
SaskPower	0	60	0	60	221	1,607	0	1,828
SERC E	502	17	0	519	0	0	0	0
SERC N	10	0	100	110	486	0	0	486
SERC SE	1,251	72	198	1,521	0	0	0	0
SPP	265	15	3	283	17,974	7,712	0	25,686
WECC AB	15	0	0	15	1,445	0	596	2,041
WECC BC	1	0	0	1	702	71	0	773
WECC CAMX	11,972	539	7,989	20,500	6,157	350	1,422	7,929
WECC NWPP US	1,776	208	8	1,992	9,997	504	400	10,901
WECC RMRG	364	191	0	555	3,176	600	30	3,806
WECC SRSG	1,359	23	213	1,595	1,112	0	464	1,576
Total	22,346	11,538	85,890	119,774	99,841	28,181	82,236	210,258

41 https://www.westerneim.com/pages/default.aspx

42 https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

ERCOT Wind Generation and Ramping

ERCOT's historic net-load ramps at minimum load conditions occur in shoulder months (February to March) time frame. The ramps are driven by wind production and have occurred in the early morning (4:00 to 5:00 a.m.) hours before solar resources are available. For this time frame, the 98th percentile three-hour upward net-load ramp can reach 11 GW. In February of 2018, ERCOT set a new wind generation record with total deployed generation capacity of 17,541 MW, which served 47 percent of ERCOT's total demand (37,336 MW). The three-hour net-load downward ramp reached -5.5 GW, and the largest three-hour net-load up ramp was 7.3 GW; however, much larger ramps, exceeding 15 GW, have been observed during different conditions.

Until 2018, regulation services were deployed to make up for a gain or loss of wind generation ramps. In April of 2018, ERCOT added intrahour wind forecasting to their real-time system operations, which increased situational awareness of potential wind generation ramps within each five-minute dispatch interval. This predicted five-minute wind ramp is assumed to be constant over the five-minute interval and has been added to the generation dispatch calculation. This change helps reduce the strain on regulation services previously used to cover the variation in the wind output. Additionally, for disturbances that occur during significant wind ramps, the intrahour wind ramps will be predicted *a priori* to the event and are therefore anticipated to reduce the Interconnection's frequency recovery duration period.

ERCOT is continuing to study net-load variability and wind ramping in their footprint. Since 2014, ERCOT has funded a research and development project on how additional variable energy resources will affect their net-load variability. The long term goal is for this work is to be incorporated into ERCOT's system planning processes. ERCOT plans to analyze the wind ramp forecast performance and update their tools as they acquire more data.

CAISO Photovoltaic Generation and Ramping

Predominant drivers for increasing ramps have been due to changes in California's load patterns, which can be attributed to an increased integration of PV DER generation across its footprint. With continued rapid growth of distributed solar, CAISO's three-hour net-load ramping needs have exceeded 14 GW. This net-load ramp rate exceeds projections made five years earlier in 2013. CAISO's actual maximum three-hour upward ramping needs were 7.6 GW in 2013 when maximum three-hour ramp rate was projected to reach 13 GW by 2020.

Surpassing projections reinforces CAISO's near-term need for access to more flexible resources in their footprint:

- Currently, there are more than 11 GW of utility-scale and 6.5 GW of behind-the-meter PV resources in CAISO's footprint, which has the most concentrated area of PV in North America.
- In March 2018, CAISO set a new ramping record with actual three-hour upward net-load ramps reaching 14,777 MW. The maximum one hour net-load upward ramp was 7,545 MW. This record coincided with utility-scale PV serving nearly 50 percent of the CAISO demand during the same time period.
- Behind-the-meter PV has continued to grow in CAISO, and the projected behind-the-meter PV is expected to be 12 GW by 2022.

Based on current projections, maximum three-hour upward net-load ramps are projected to exceed 17,000 MW in March by 2021, approximately 20 percent greater than the amount projected for 2018 (**Figure 1.17** on the next page).

Ramp Monitoring and Planning Considerations

The trends in California and ERCOT highlight the importance for industry to focus on evaluating the ability of the resource mix to adequately meet net-load ramping needs as more renewables are added to their respective systems. NERC's assessment finds the following:

- Ramping should be monitored in any area that projects significant growth in the amount of nondispatchable resources.
- Ramps are most extreme during the off-peak (shoulder) months of the year, typically during low-load conditions in the spring and fall; however, during peaking conditions, flexible resources may be scarce.
- Monitoring and improving individual generator ramp rates will support changing operational schedules.
- The visibility of DERs can present challenges for operators, but these challenges can be managed with net metering or aggregated metering at subtransmission substations.
- Operating rules in some areas should be considered to determine if alterations are needed to schedule distributed PV resources using net metering.

As an alternative to operating changes, strategic installation of energy storage (e.g., batteries) and scheduling of these resources can assist with reducing ramps and optimizing existing constraints.

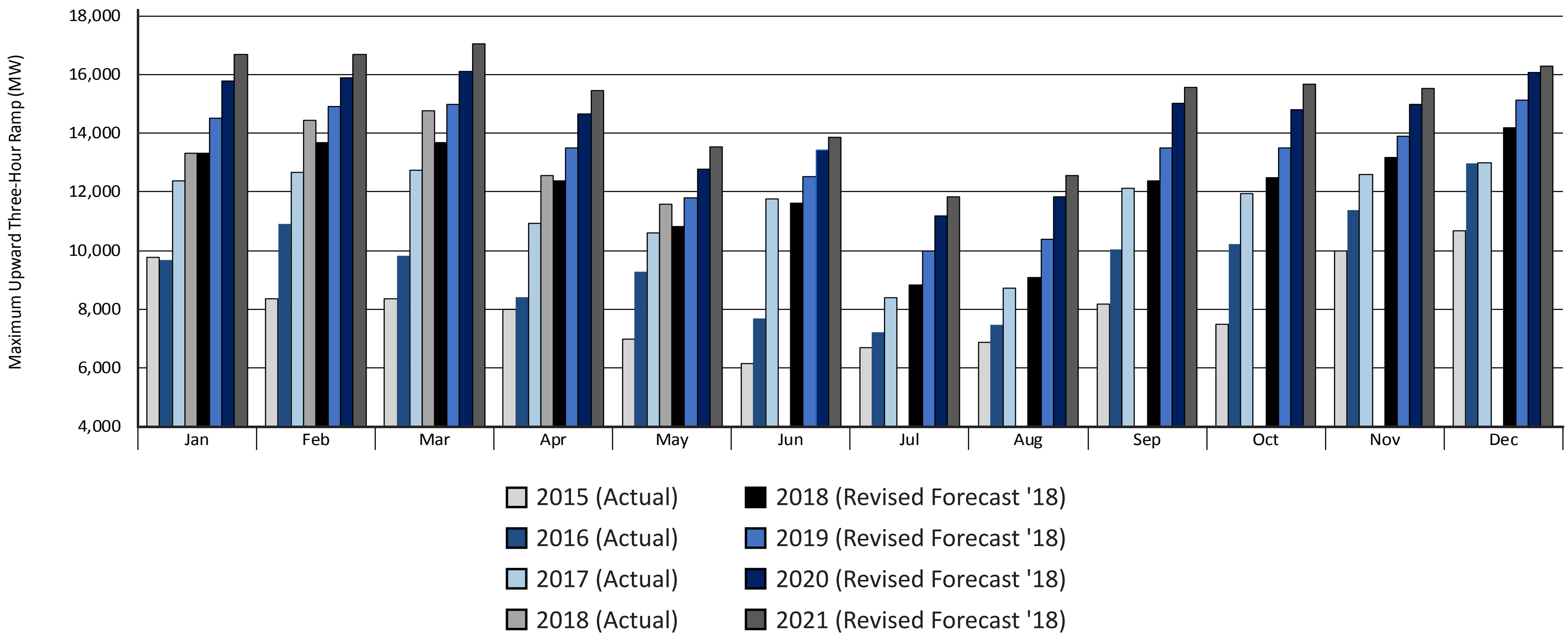


Figure 1.17: Maximum 3-Hour Ramps in CAISO (Actual and Projected) through 2021

Key Finding 5: Over 30 GW of New Distributed Solar Photovoltaic Expected by the End of 2023 to Impact System Planning, Forecasting, and Modeling Needs

Key Points:

- A total of 30 GW of distributed solar PV is expected over the next five years, primarily in states of California, New Jersey, Massachusetts, and New York, increasing the United States total to nearly 51 GW by the end of 2023.
- Increasing installations of DERs modify how distribution and transmission systems interact with each other.
- Transmission planners and operators may not have complete visibility and control of these resources, but as growth becomes considerable, their contributions should be considered in system planning, forecasting, and modeling.

The generation mix is undergoing a transition from large, synchronously connected generators to smaller natural-gas-fired generators, renewable energy, and DR. The growing interest in a more decentralized electric grid and new types of distributed resources further increases the variety of market stakeholders and technologies. Both new and conventional stakeholders are building or planning to build distributed solar PV systems, energy management systems, microgrids, demand services, aggregated generation behind the retail meter, and many other types of distributed generation. Many of these stakeholders have considerable experience with installing such systems on the distribution network for the benefit of industrial or residential customers but may have less familiarity with the BPS and the coordinated activities that ensure system reliability during both normal operation and in response to disturbances.

Progress Made in 2018

The Energy Policy Act of 2005 requires electric utilities to provide interconnection services "based on standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time."[43] In 2018, a new version of the IEEE 1547 (*Standard for Interconnecting Distributed Resources with Electric Power Systems*) was finalized, but it will not be fully implemented until 2020 or later due to further certification and approvals by UL.[44] The new standard now provides specifications that help inverters connected at the distribution system to be aligned with BPS transmission protection requirements in that area. A fact sheet developed by EPRI provides a summary of the detailed specifications and features constructed within the revised standard.[45]

The revised standard provides a foundation for DERs to play an active role in supporting local reliability needs. In the near future, technology advances have the potential to alter DERs from a passive "do no harm" resource to an active "support reliability" resource. From a technological perspective, modern DER units will be capable of providing essential reliability services, such as frequency and voltage support. These technologies are likely to become more widely available in the near future and they present an opportunity to enhance BPS performance when applied in a thoughtful and practical manner.

Also in 2018, NERC implemented a reliability guideline approved by NERC's PC that provides information and guidance relevant for collecting the data needed by system planners to sufficiently represent and model different types of utility-grade DERs and residential-grade DERs in stability analyses.[46] As a growing component of the overall load characteristic, it is important the system planners are able to assess how DER performance impacts the BPS.

[43] EPACT-2005, Public Law 109–58, August 8, 2005

[44] UL 1741 is the UL *Standard for Safety for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources:* https://standardscatalog.ul.com/standards/en/standard_1741_2

[45] EPRI: *IEEE 1547 - New Interconnection Requirements for Distributed Energy Resources Fact Sheet:* https://publicdownload.epri.com/PublicDownload.svc/product=000000003002011346/type=Product

[46] NERC *Reliability Guideline Distributed Energy Resource Modeling*: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf

Projection of Distributed Resources

Based on projections from GTM Research,[47] in the United States, nonutility DER installations are expected to increase 30 GW to nearly 51 GW by the end of 2023 (**Figure 1.18**). California, New Jersey, Massachusetts, and New York see the largest increases over the next five years (**Figure 1.19** on the next page). In Canada, Ontario has already installed just over two GW of DER and less than 500 MW are expected in the coming years.

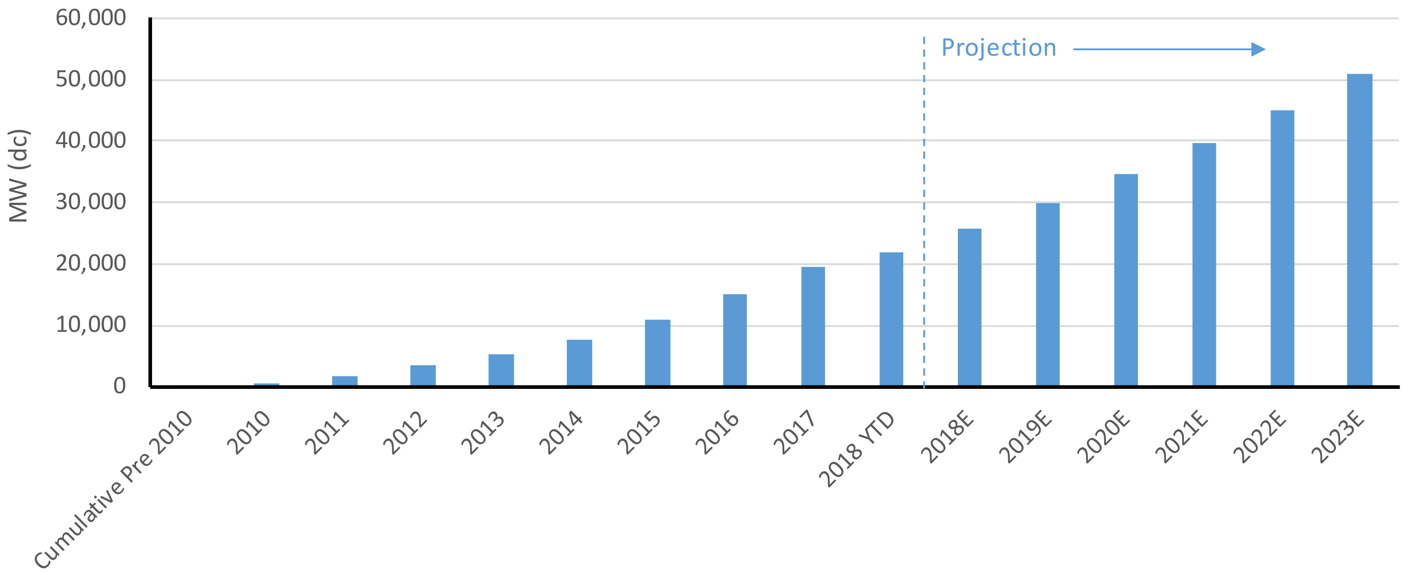


Figure 1.18: United States Cumulative Total Amount of Distributed Solar PV—2010 through 2023

NERC Reliability Guidelines: It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the BES. The NERC technical committees—the OC, the PC, and the Critical Infrastructure Protection Committee (CIPC)—are authorized by the NERC Board to develop reliability (OC and PC) and security (CIPC) guidelines per their charters. These guidelines establish voluntary recommendations, considerations, and industry best practices on particular topics for use by users, owners, and operators of the BES to help assess and ensure BES reliability. These guidelines are prepared in coordination between NERC staff and the NERC technical committees. As a result, these guidelines represent the collective experience, expertise, and judgment of the industry.

The objective of each reliability guideline is to distribute key practices and information on specific issues to support high levels of BES reliability. Reliability guidelines do not provide binding norms and are not subject to compliance and enforcement (unlike Reliability Standards that are monitored and subject to enforcement). Guidelines are strictly voluntary and are designed to assist in reviewing, revising, or developing individual entity practices to support reliability for the BES. Further, guidelines are not intended to take precedence over Reliability Standards, regional procedures, or regional requirements.

[47] https://www.greentechmedia.com/research/solar

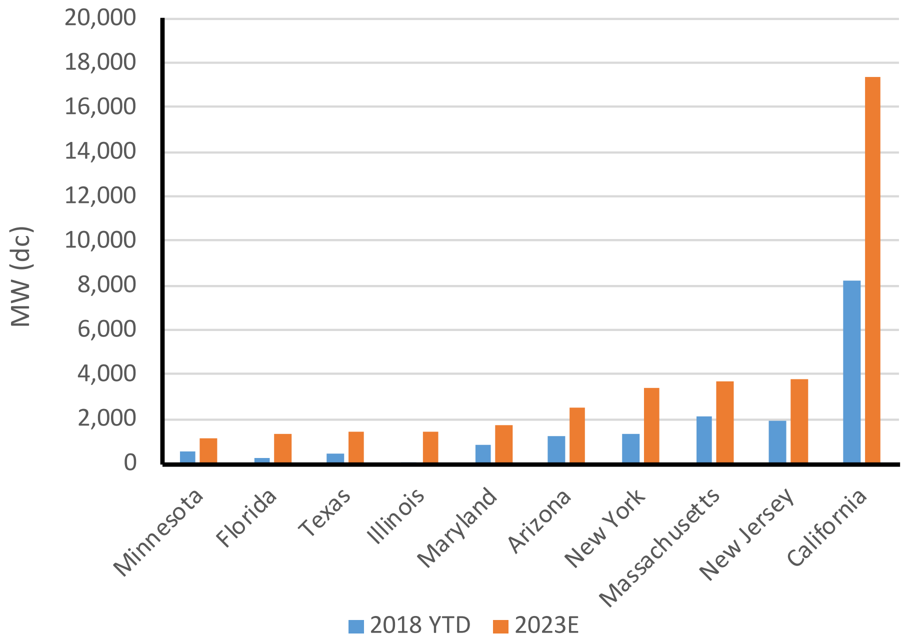


Figure 1.19: Top 10 States with Increasing Amounts of Distributed Solar PV—Total Installed for 2018 and 2023 projection

Reliability Considerations

Increasing amounts of DERs can change how the distribution system interacts with the BPS and will transform the distribution system into an active source for energy and essential reliability services. Overall, reliability risks concerning larger penetrations of DERs can be summarized by three major aspects:

- Difficulty in obtaining and managing the amount of data concerning DER resources, including their size, location, and operational characteristics
- A current inability to observe and control most DER resources in real time
- A need to better understand the impacts on system operations of the increasing amounts of DERs, including ramping, reserve, frequency response, and regulation requirements

Today, the effect of aggregated DERs is not fully represented in BPS models and operating tools. This could result in unanticipated power flows and increased demand forecast errors. An unexpected loss of aggregated DER could also cause frequency and voltage instability at sufficient DER penetrations. The system operator typically cannot observe or control DERs, so variable output from DERs can contribute to ramping and system balancing challenges. This presents challenges for both the operational and planning functions of the BPS. In certain areas, DERs are being connected on the distribution system at a rapid pace, sometimes with limited coordination between DER installation and BPS planning activities. With the rapid rate of DER installations on distribution systems, it will be necessary for the BPS planning functions to incorporate future DER projections in BPS models. These changes will affect not just the flow of power but also the behavior of the system during disturbances. It is important to coordinate the planning, installation, and operation of DERs in relation to the BPS as transition to a new resource mix occurs.

At low penetration levels, the effects of DERs may not present a risk to BPS reliability. However, as penetrations increase, the effect of these resources can present certain reliability challenges that require attention. This leads to areas where further consideration is needed to better understand the impacts and how those effects can be included in planning and operations of the BPS. A recent NERC report, *Distributed Energy Resources: Connection, Modeling, and Reliability Considerations*, provides a detailed assessment of DER and its potential impacts to BPS reliability.[48]

Regional Considerations

Table 1.10 on the next page presents regional considerations by assessment areas or Regions with at least one GW or expecting at least one GW of DERs in the coming years.

[48] *NERC Distributed Energy Resources: Connection, Modeling, and Reliability Considerations:* https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

Table 1.10: Actions by Industry in Response to Growth in DERs	
Assessment Area	**Activities to Address Risks Related to Emerging DERs**
FRCC	FRCC has relatively low penetration levels of DERs with modest growth expected throughout the planning horizon. Multiple FRCC Subcommittees are reviewing recommendations developed by the FRCC Solar Task Force, which was tasked with examining and determining procedures and processes to address the projected growth of central station solar resources within the assessment area.
MISO	The OMS DER[1] survey is part of an ongoing initiative to help state and local regulators make informed decisions as DER adoption increases. MISO has not experienced any operational challenges as of yet but expects to as programs grow in the future.
NPCC-New England	DERs are reflected in planning studies, including resource adequacy, transmission planning, and economic studies. ISO-NE and the states are addressing other potential reliability risks posed by growing penetrations of PV installations, such as by supporting revisions to PV Interconnection requirements found in the relevant IEEE standards.
NPCC-New York	DERs may participate in certain NYISO energy, ancillary services, and capacity markets. In February 2017, the NYISO published a report providing a roadmap that the NYISO will use over the next three to five years as a framework to develop the market design elements, functional requirements, and tariff language necessary to implement the NYISO's vision to integrate DERs.[2] A solar forecasting system to integrate with the day-ahead and real-time markets was implemented in 2017. Two data streams are being produced: zonal data for behind-the-meter solar PV installations and bus-level data for utility-scale solar PV installations.
NPCC-Ontario	As a result of the increase of DERs in Ontario, the IESO has seen periods where embedded generation had significant offsetting impacts on Ontario demand. Having visibility of these resources is imperative for improving short-term demand forecasting and reliable grid operation. IESO is working through the Grid-LDC Interoperability Standing Committee to increase coordination between the grid operator and embedded resources directly or through integrated operations with local distribution companies with the aim to improve visibility of the distribution system and therefore reduce short-term forecast errors. To enable greater flexibility, the IESO is initiating control actions, such as manually adjusting variable generation forecasts, committing dispatchable generation, and curtailing intertie transactions. The IESO is now able to schedule additional 30-minute operating reserve to represent flexibility need.
PJM	PJM tracks DER installations through its Generation Attribute Tracking System and allows PJM to incorporate the information into its load forecast. Additionally, a DER Subcommittee was established by the Markets and Reliability Committee on December 7, 2017. Its purpose is to investigate and resolve issues and procedures associated with markets, operations, and planning related to DERs in accordance with existing or new PJM process protocols.
SERC	DERs are not explicitly modeled as generators but are instead modeled as a reduction in bus load, netting the actual bus load and the on-line DER generation. Entities are actively establishing processes to use available data to explicitly model the bus load and DER generation independently to better represent these DER in planning models.
TRE-ERCOT	ERCOT published a whitepaper *Distributed Energy Resources: Reliability Impacts and Recommended Changes*[4] outlining the challenges and potential impacts of DERs. A Nodal Protocol Revision Request (NPRR 866[5]) has been submitted by ERCOT staff that will require the mapping of all existing registered DERs (>1 MW that export) to the Common Information Model at their load points. Once in the model, the DER locations will be known to operators in the ERCOT control room, improving situational awareness, and can also be incorporated into the power flow, state estimator, and load forecast programs. Based on current modeling practice, individual DERs are included in all transmission planning study cases to the extent that they are communicated to ERCOT by the responsible TDSP during the model building process. Generally, these are modelled as a gross reduction of the load at the point of interconnection. However, they are modeled as generators with a negative load in some cases. Although the behavior of many resource technologies (solar PV, landfill natural gas, small hydro, etc.) can be predicted, ERCOT will need more analysis to determine how to incorporate self-dispatched DERs in the studies.
WECC	Largely due to the significant amount of DERs (and utility-grade solar) in California, the entire Interconnection must help support the energy imbalances caused by significant ramping events occurring almost daily. To better understand the implications to the Western Interconnection, WECC is addressing modeling develop and data collection procedures to ensure DERs are represented in Interconnection models.[6] Power flow models can include DERs as data input, but currently none of these models have been approved for use in the Western Interconnections. WECC's Modeling and Validation Work Group (MVWG) is in the process of approving these models for future use.

1 http://www.misostates.org/images/Documents/Public_OMS_DER_Survey_Results_as_of_July_31_2018.pdf

2 http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/Distributed_Energy_Resources/Distributed_Energy_Resources_Roadmap.pdf

Chapter 2: Emerging Reliability Issues

As part of the annual LTRA, NERC staff, industry representatives, and subject-matter experts identify and assess the impact of key issues and trends that may affect reliability in the future, such as market practices, industry developments, potential technical challenges, technology implications, and policy changes. The data NERC collected for this assessment incorporates known policy and regulation changes expected to take effect throughout the 10-year time frame assuming a variety of factors, such as economic growth, weather patterns, and system equipment behavior, but it does not predict certain outcomes that have not been formally announced or made public. For example, significant amounts of bulk battery storage have not materialized enough to be observed in the data sets; however, we know the technology is advancing and is on the brink of playing a significant role in reliability in the coming years. While we may not be able to measure the exact quantities being contemplated, analysis can be completed to identify challenges and opportunity to reliability.

Bulk Power Storage

Energy storage has the potential to offer much needed capabilities to maintain grid reliability and stability. With the exception of pumped hydro storage facilities, only a limited number of large-scale energy storage demonstration projects have been built. With increasing requirements for system flexibility as variable generation levels increase and energy storage technology costs decrease, bulk system and distributed stationary energy storage applications may become more viable and prevalent. Storage may be used for load shifting and energy arbitrage—the ability to purchase low-cost, off-peak energy and re-sell the energy during high-peak, high-cost periods. Storage may also provide ancillary services such as regulation, load following, contingency reserves, and capacity. This is true for both bulk storage, which acts in many ways like a central power plant, and distributed storage technologies.

At the end of 2017, approximately 708 MW of utility-scale storage of differing types,[49] such as batteries, flywheels, and compressed air was in operation. In California alone, legislation requires investor owned utilities to procure 1,325 MW of energy storage by 2020.[50] A total of 84 different projects across the United States are currently "planned," according to the U.S. Energy Information Administration.

[49] This does not include pumped hydro storage.

[50] https://www.eia.gov/analysis/studies/electricity/batterystorage/

Reliability Coordination in the West Interconnection

Reliability concerns can arise where seams exist between operating entities. In light of the changes occurring in the Western Interconnection, it is vital that clear and precise operating responsibilities are defined and understood and that coordination occurs between the entities responsible for maintaining reliability. Functional separation of traditional generation, transmission, and distribution responsibilities has amplified the potential for operational conflicts and disagreements over reliability functions and system control authority. System operators need to be aware of and committed to taking necessary actions to preserve reliability. A clearly understood hierarchy must be in place for each defined operating area with well-defined responsibilities for all operating functions. Reliability coordinators (RCs) are responsible for monitoring and assessing the condition of the system over a wide area and must be able to issue directives to other operating authorities in the area to take action to maintain overall system reliability. While the level of physical control given to the RC can vary between organizational models, operating entities must respond promptly to instructions from the RC. When multiple control areas are consolidated, the transfer of control area responsibilities and system operational knowledge must be effective and complete. All parties involved must have the ability and knowledge to reliably operate their systems, as confirmed by appropriate training and testing, before responsibilities are turned over. During this transition period, all parties must be vigilant to ensure that system reliability is maintained.

Peak Reliability (Peak) announced the wind-down of the organization and the transition of RC services from Peak to alternative providers by the end of 2019. During this transition and planning period, Peak will continue to focus on operational excellence as an RC through December 31, 2019. The transition plan will also include discussions between Peak, the presumptive successor RCs (e.g., California Independent System Operator (CAISO), Southwest Power Pool (SPP), and other stakeholders) to assure that reliability and security are maintained.

As of September 14, entities representing 98 percent of the net energy for load (NEL) in the Western Interconnection had expressed nonbinding commitments to join various RCs. The current nonbinding commitments include approximately 72 percent of the load selecting the CAISO RC, approximately 12 percent selecting SPP RC, and approximately seven percent selecting British Columbia Hydro and Power Authority (BCH) (becoming a new RC) as their preferred RC. The Alberta Electric System Operator (AESO) will continue to provide RC services for the Alberta province.

With the formation of multiple RCs, institutional knowledge of operational procedures needs to be reviewed and communicated accordingly. Real-time operational models used for studies need to be coordinated. Operational planning studies should include contingencies and element outages (planned and forced) in adjacent systems and monitor facilities next to the RC footprint to identify third-party and seams impacts.

The RC-to-RC Coordination Group, which includes subject matter experts from BCH, AESO, SPP, CAISO, and Peak have found five major RC task tracks that are now being reviewed. The five tracks are operations planning, operations coordination, wide-area tools, technology and data sharing, and modeling (including remedial action scheme modeling). These tracks have several subgroups working out the specifics of transitioning the necessary activities.

WECC continues to host a series of RC forums to give stakeholders the opportunity to understand and discuss the reliability implications of multiple RCs in the Western Interconnection. Additionally, NERC and WECC staff continue to take part in various RC forums and provide updates at various stakeholder committee and Board meetings to ensure transparency in the creation of and transition to multiple RCs.

Potential Risk of Significant Electricity Demand Growth

A rapid onset of transportation-related or industrial demand could create unexpected load growth. Automobiles are now increasingly battery-powered. Electric heating is also driving efficiency increases as heat pumps replace other forms of heating, including natural gas, oil, and direct electric heating on broader scales. Plug-in electric vehicles are projected to account for as much as half of all United States new car sales by 2030. The electricity required to charge these vehicles will increase demand on BPS.

Scenario analysis is the best method to understand these potential risks. For example, how might a three-fold increase in electric vehicle penetration by 2028 affect the reliability of the BPS? Would there be a change in planning and/or operating reserve requirements? Would charging patterns affect ramping needs? Could the increased availability of mobile electric storage devices create market opportunities that could, in turn, affect grid operations? These questions, and more, are likely options for continued assessment of this emerging issue.

Reactive Power Requirements for Transmission-Connected Devices

Increasing amounts of reactive power are being supplied by nonsynchronous sources and power electronics. There are two components to the power supplied by conventional electric generators: real power and reactive power. Reactive devices will increasingly be used to replace dynamic voltage support lost from conventional generation retirements. These devices include static var compensators, static synchronous compensators, and synchronous condensers. While many technologies can provide reactive support, NERC Reliability Standards only apply to generation. There may be a need to more clearly articulate performance specifications of these devices.

As more reactive support is provided by new technologies, it is prudent to monitor their performance to better understand any reliability or system interaction issues. Inventory, projections, and performance data are needed to better evaluate the risk.

DER Impacts on Automatic Under-Frequency/Under Voltage Load Shedding (UFLS/UVLS) Protection Schemes

The effect of aggregated and increasing DERs may not be fully represented in BPS planning models and operating tools. UFLS/UVLS schemes rely on the rapid disconnection of load during frequency or voltage excursions. These schemes use fast acting relays to disconnect load to help arrest and recover from degrading system frequency or voltage. However, in some cases, DER resources are “netted” with distribution load when measured and modeled. Consequently, the system operator may not be aware of the total load compared to the total interconnected resources that are behind-the-meter. Should a system excursion exceed the inverter protection settings, it is likely that DERs may automatically disconnect, resulting in both the loss of resources and an increase in load that was served by the lost DERs. The increase in net load during such an event can exacerbate the underlying disturbance that caused the voltage or frequency excursion. Additionally, as DERs are integrated with more load, the response in real-time may not result in what was modeled or simulated.

This risk is largely a function of the amount of concentrated DERs at local distribution feeders. As more DERs are added, system planners may need to adapt their protection schemes to account for the changing system characteristics. There are at least two major events that have occurred on the European power system where the disconnection of DERs played a role in system collapse.[51]

System Restoration

The changing resource mix introduces new challenges to system restoration and resilience to extreme weather conditions. Retiring conventional generation that has supported the blackstart capability of the system or is critical to "cranking paths" may impact system resilience in terms of being able to recover rapidly. With more decentralized resources, additional complexity exists in coordinating restoration between these generating units and system operator control rooms. Additional challenges exist, including availability of energy input (i.e., sunlight, wind) during system restoration and the ability to provide "grid-forming" services during blackstart conditions. Thus, for existing wind and solar PV resources to participate in system restoration, they currently must follow and coordinate with a grid voltage and frequency that has been set by a synchronous generation resource. Large-scale capability for blackstart with wind and solar PV are possible if this is a desired feature but are several years away from commercial availability. More research and study is needed by the electric industry to understand the implications of the changing resource mix to blackstart capability.

[51] **Italy Blackout 2003:** On September 28, 2003, a blackout affected more than 56 million people across Italy and areas of Switzerland. The disruption lasted for more than 48 hours as crews struggled to reconnect areas across the Italian peninsula. The reason for the blackout was that during this phase the UVLS could not compensate the additional loss of generation when approximately 7.5 GW of distributed power plants tripped during under-frequency operation. **European Blackout 2006:** On November 4, 2006, at around 22:10, the UCTE interconnected grid was affected by a serious incident originating from the North German transmission grid that led to power supply disruptions for more than 15 million European households and a splitting of the UCTE synchronously interconnected network into three areas. The imbalance between supply and demand as a result of the splitting was further increased in the first moment due to a significant amount of tripped generation connected to the distribution grid. In the over-frequency area (Northeast), the lack of sufficient control over generation units contributed to the deterioration of system conditions in this area (long lasting over-frequency with severe overloading on high-voltage transmission lines). Generally, the uncontrolled operation of dispersed generation (mainly wind and combined-heat-and-power) during the disturbance complicated the process of re-establishing normal system conditions.

Potential Impact to System Strength and Fault Current Contributions

As inverter-based resources replace conventional generation, short-circuit current availability can be impacted due to the limited fault current contribution of renewable generation. Low short-circuit conditions increases the likelihood of sub-synchronous behavior and control interactions among neighboring devices that use power electronics, including protection relays.[52] More industry guidance is needed to assess low short-circuit conditions on the BPS, system implications, desired inverter response, and potential solutions to mitigate these issues. Assessment techniques to identify low fault current conditions should continue to be advanced by transmission planners while considering light-load and low fault current conditions. Short-circuit ratio calculations and wide-area relay sensitivity studies should be performed to identify locations susceptible to low fault current issues.

In April 2018, ERCOT conducted an assessment of Texas Panhandle and South Texas stability and system strength.[53] The study analyzed operating conditions for high concentrations of wind generation in the Panhandle area and, for the first time, in the Rio Grande Valley, which also is seeing a significant amount of wind generation development. The study showed that there are electric system stability limitations when wind and solar resources are unable to detect voltage signals due to a lack of thermal/synchronous generation in an area. While previous studies have been conducted to help identify stability limits in the Panhandle, this recent study showed the benefits of using more accurate and detailed models and provided information on the interaction between customer demand and stability limits. ERCOT plans to use this data to help inform future studies and better understand the reliability implications associated with increased variable generation on the electric system. Further, other interconnection study and seams coordination groups would benefit from understanding the analytical approaches and lessons learned from the ERCOT assessment.

Finally, the renewable industry has been working on this issue for a long time, and there are many solutions, including changing control settings to avoid harmful interactions, building transmission to strengthen the grid, or deploying synchronous condensers.

[52] ERCOT, System Strength Assessment of the Panhandle System.

[53] http://www.ercot.com/content/wcm/lists/144927/Panhandle_and_South_Texas_Stability_and_System_Strength_Assessment_March....pdf)

Chapter 3: Demand, Resources, and Trends

The following graphic summarizes the projected trends, demand, and capacity resources over the 10-year planning horizon of the LTRA along with the historic changes since 2012.

10-Year Outlook	▪ A 10-year compound annual growth rate (CAGR) of demand for North America is the lowest on record, at 0.57 percent (summer) and 0.59 percent (winter). ▪ Load growth in all assessment areas is under two percent, with five assessment areas projecting reduced peak demand.	▪ Natural-gas-fired capacity has increased to 442 GW from 280 GW in 2009. ▪ A total of 60 GW of Tier 1 natural gas-fired capacity additions are planned through 2028. ▪ Natural-gas-fired capacity is the primary on-peak fuel type in 10 assessment areas.	▪ More than 28 GW (nameplate) of Tier 1 wind additions are planned by 2028—82 GW of Tier 2. ▪ The amount of peak capacity ranges from 7–34 percent of the total nameplate capacity.	▪ A total of 46.5 GW of coal-fired generation retirements since 2011, with 19 GW of confirmed retirements planned between 2017 and 2027. ▪ A total of seven nuclear units have retired since 2012, and 14 plan to retire by 2025.	▪ Solar resources are expected to increase by 12 GW (nameplate) of Tier 1 planned by 2028—86 GW of Tier 2. ▪ The amount of peak capacity ranges from 0–68 percent of the total nameplate capacity.

Demand Projections

NERC-wide electricity peak demand and energy growth are at the lowest rates on record with declining demand projected in five assessment areas. The 2018 through 2028 aggregated projections of summer peak demand NERC-wide are slightly lower than last year's projection. A comparison of this year's 10-year forecasted growth to last year's 10-year forecasted growth indicates that peak demand is roughly flat for North America as a whole.

Figure 3.1 identifies the 10-year compound annual growth rate (CAGR) of peak demand as the lowest on record at 0.57 percent (summer) and 0.59 percent (winter). Also, the 10-year energy growth is 0.58 percent per year, compared to more than 1.48 percent just a decade earlier (**Figure 3.2**).[54]

[54] Prior to the *2011 LTRA*, the initial year of the 10-year assessment period is the report year (e.g., the 10-year assessment period for the *1990 LTRA* was 1990–1999). The *2011 LTRA* and subsequent LTRAs examine the initial year of the assessment period as one year out (e.g., the 10-year assessment period for the *2012 LTRA* is 2013–2022).

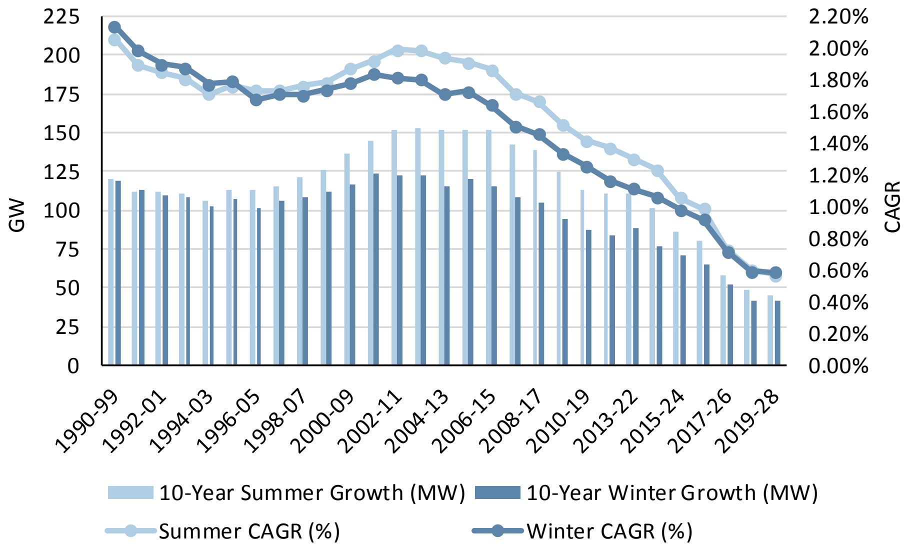


Figure 3.1: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

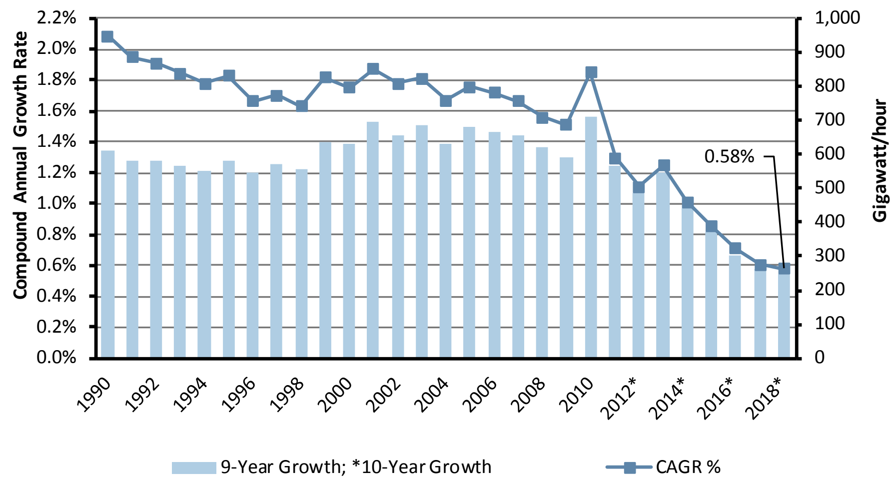


Figure 3.2: 10-Year Net Energy to Load Growth and Rate Projection Trends

Understanding Demand Forecasts: Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise their forecasts on an annual basis or as their resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts, generally as of May 2018, of the individual planning entities and load-serving utilities comprising the REs. These forecasts are typically "equal probability" forecasts. That is, there is a 50 percent chance that the forecast will be exceeded and a 50 percent chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are internal electricity demands that have already been reduced to reflect the effects of demand-side management programs, such as conservation, energy efficiency, and time-of-use rates. It is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, dispatchable and controllable DR is included in net internal demand.

A 10-year demand growth in all assessment areas is under two percent per year with five assessment areas projecting a decline in demand (**Figure 3.3**).

Continued advancements of energy efficiency programs, combined with a general shift in North America to less energy-intensive economic growth, are contributing factors to slower electricity demand growth. Thirty states in the United States have adopted energy efficiency policies that are contributing to reduced peak demand and overall energy use.[55] Additionally, DERs and other behind-the meter resources continue to increase and reduce the net demand for the BPS even further.

The planning reserve margins for the years 2019–2023 are shown in **Tables 3.1** and **3.2** on the next two pages. **Table 3.3** on page 52 shows the reference margin levels for each assessment area.

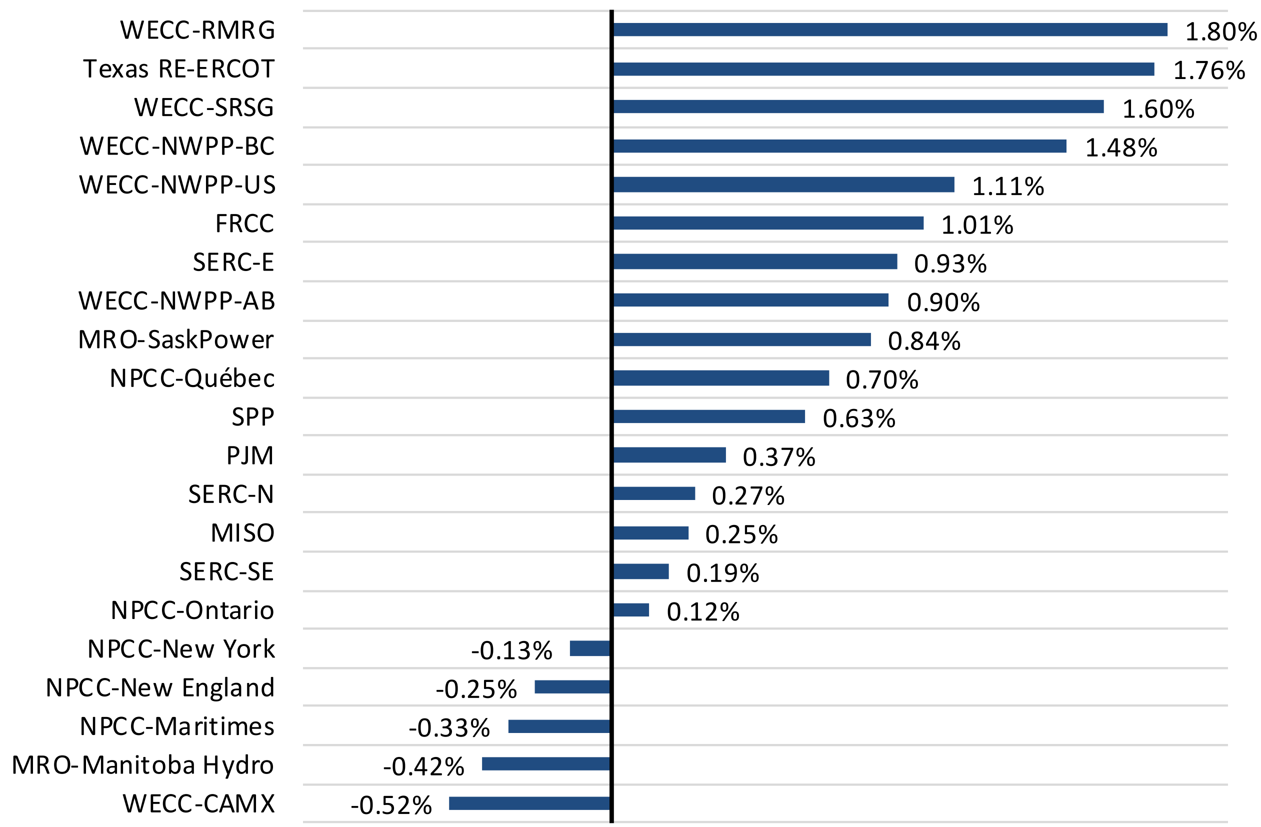


Figure 3.3: Annual Peak Demand Growth Rate for 10-Year Period by Assessment Area

55 EIA - Today in Energy: Many states have adopted policies to encourage energy efficiency.

Table 3.1: Planning Reserve Margins (2019–2023)											
Assessment Area	**Reserve Margins (%)**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
FRCC	Anticipated	23.93	23.70	22.52	24.43	25.33	24.12	22.86	21.59	20.52	20.26
	Prospective	24.93	24.69	23.26	26.15	28.36	28.10	26.79	25.51	25.37	25.11
	Reference Margin Level	15.0	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
MISO	Anticipated	21.28	21.68	20.34	18.86	16.84	15.76	15.04	14.47	14.07	14.41
	Prospective	20.87	23.71	24.46	40.85	42.88	41.45	40.82	39.30	38.54	38.90
	Reference Margin Level	17.10	17.10	17.10	17.10	17.10	17.10	17.10	17.10	17.10	17.10
MRO-Manitoba Hydro	Anticipated	22.09	24.11	31.58	43.48	44.60	45.26	45.11	44.83	44.29	45.30
	Prospective	20.66	17.30	19.60	31.40	32.42	33.03	35.73	35.46	37.27	38.34
	Reference Margin Level	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
MRO-SaskPower	Anticipated	20.12	18.78	17.68	13.74	20.29	22.15	18.64	16.58	26.92	18.34
	Prospective	20.12	18.78	17.68	13.74	20.29	22.15	18.64	16.58	26.92	18.34
	Reference Margin Level	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00
NPCC-Maritimes	Anticipated	23.46	24.22	25.41	27.56	28.45	29.13	29.78	30.01	30.26	30.39
	Prospective	25.16	25.74	26.22	28.35	29.21	28.01	28.35	22.70	22.94	23.06
	Reference Margin Level	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
NPCC-NewEngland	Anticipated	29.43	29.92	32.28	28.46	28.98	29.36	29.57	29.56	29.40	29.24
	Prospective	31.60	32.49	35.65	32.13	33.33	33.84	34.77	34.77	34.60	34.42
	Reference Margin Level	16.91	17.20	16.36	16.36	16.36	16.36	16.36	16.36	16.36	16.36
NPCC-NewYork	Anticipated	21.57	24.12	21.64	22.53	22.74	22.77	22.68	22.51	22.28	22.02
	Prospective	21.50	26.47	27.31	28.22	30.06	30.09	30.00	29.82	29.57	29.30
	Reference Margin Level	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
NPCC-Ontario	Anticipated	28.63	27.08	23.30	23.63	18.62	12.27	16.04	17.18	16.54	12.81
	Prospective	28.24	25.97	22.20	22.52	19.53	10.87	13.70	14.81	14.19	10.46
	Reference Margin Level	18.37	18.05	18.02	18.51	19.43	21.59	22.69	25.43	22.92	21.60
NPCC-Québec	Anticipated	16.35	14.48	13.60	15.04	12.86	12.10	11.35	10.35	9.44	8.57
	Prospective	19.37	17.48	16.58	18.00	15.79	15.02	14.25	13.23	12.30	11.41
	Reference Margin Level	12.61	12.61	12.61	12.61	12.61	12.61	12.61	12.61	12.61	12.61
PJM	Anticipated	33.12	35.46	35.66	35.20	34.53	34.00	33.40	32.73	31.98	31.11
	Prospective	42.10	53.95	58.30	61.27	61.36	60.73	60.01	59.21	58.30	57.26
	Reference Margin Level	15.90	15.90	15.80	15.80	15.80	15.80	15.80	15.80	15.80	15.80

Table 3.2: Planning Reserve Margins (2019–2023)											
Assessment Area	**Reserve Margins (%)**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
SERC-E	Anticipated	23.28	21.05	20.93	22.29	21.48	20.36	21.94	23.35	21.78	18.50
	Prospective	23.38	21.14	21.03	22.39	21.57	20.45	22.04	23.45	21.87	18.59
	Reference Margin Level	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
SERC-N	Anticipated	25.70	25.71	25.56	25.21	24.58	24.40	24.02	23.20	22.98	22.80
	Prospective	31.22	31.20	31.04	30.68	30.02	29.84	29.44	28.58	28.35	28.16
	Reference Margin Level	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
SERC-SE	Anticipated	32.15	31.67	30.92	32.53	33.77	33.03	32.44	30.58	33.09	34.15
	Prospective	34.25	33.76	33.21	34.82	36.04	35.29	34.69	32.80	35.34	36.42
	Reference Margin Level	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
SPP	Anticipated	32.29	30.37	29.68	27.19	25.15	23.93	23.33	22.31	21.00	19.34
	Prospective	32.06	29.81	29.12	26.65	24.06	22.85	21.94	20.94	19.63	17.90
	Reference Margin Level	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
TRE-ERCOT	Anticipated	11.17	12.66	11.82	10.60	8.62	6.91	5.35	3.64	1.98	0.37
	Prospective	19.06	38.14	45.45	44.90	41.83	39.66	37.63	35.40	33.23	31.12
	Reference Margin Level	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75
WECC-AB	Anticipated	26.76	25.93	24.62	23.44	22.83	21.77	20.52	19.37	18.10	16.91
	Prospective	29.60	28.74	27.41	26.20	25.58	24.50	23.22	22.04	20.74	19.52
	Reference Margin Level	10.42	10.36	10.28	10.21	10.14	10.05	9.95	9.88	9.80	9.73
WECC-BC	Anticipated	19.22	18.77	17.65	15.93	14.23	12.75	11.55	10.08	8.27	6.67
	Prospective	19.22	18.77	17.65	15.93	14.23	19.43	18.14	16.59	14.67	12.97
	Reference Margin Level	10.42	10.36	10.28	10.21	10.14	10.05	9.95	9.88	9.80	9.73
WECC-CAMX	Anticipated	23.27	30.55	24.26	23.63	24.51	20.65	20.35	20.86	20.67	20.27
	Prospective	32.50	43.28	42.13	42.88	43.89	40.17	39.82	40.40	40.18	39.72
	Reference Margin Level	12.35	12.29	12.10	12.05	12.02	12.05	11.99	11.99	12.02	12.04
WECC-NWPP-US	Anticipated	27.57	25.92	24.62	22.75	23.82	23.64	23.65	23.68	26.46	22.03
	Prospective	27.77	26.12	24.81	22.94	24.01	23.83	23.83	23.86	26.64	22.22
	Reference Margin Level	19.72	19.68	19.53	19.60	19.56	19.49	19.39	19.35	19.27	19.11
WECC-RMRG	Anticipated	33.72	26.56	24.89	23.48	21.14	19.63	18.04	16.78	15.52	14.04
	Prospective	33.72	26.56	24.89	23.48	21.47	19.95	18.36	17.10	15.84	14.35
	Reference Margin Level	16.83	16.76	16.48	16.37	16.07	15.94	15.73	15.58	15.40	15.25
WECC-SRSG	Anticipated	30.80	29.40	27.46	24.03	20.90	18.84	16.64	15.04	11.97	10.54
	Prospective	33.63	32.37	30.87	27.45	24.26	22.14	19.88	18.24	15.11	13.64
	Reference Margin Level	15.10	15.11	14.86	14.63	14.47	14.33	14.17	14.03	13.92	13.82

Table 3.3: Reference Margin Levels for each Assessment Area (2019–2023)					
Assessment Area	Reference Margin Level	Assessment Area Terminology	Requirement?	Methodology	Reviewing or Approving Body
FRCC	15%[1]	Reliability Criterion	No: Guideline	0.1/Year LOLP	Florida Public Service Commission
MISO	17.1%	Planning Reserve Margin	Yes: Established Annually[2]	0.1/Year LOLE	MISO
MRO-Manitoba Hydro	12%	Reference Margin Level	No	0.1/Year LOLE/LOEE/ LOLH/EUE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	11%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
NPCC-Maritimes	20%[3]	Reference Margin Level	No	0.1/Year LOLE	Maritimes Subareas; NPCC
NPCC-New England	16.3–17.2%	Installed Capacity Requirement	Yes: three-year requirement established annually	0.1/Year LOLE	ISO-NE; NPCC Criteria
NPCC-New York	15%	Installed Reserve Margin	Yes: one year requirement; established annually based on full installed capacity values if resources	0.1/Year LOLE	NYSRC; NPCC Criteria
NPCC-Ontario	18–25%	Ontario Reserve Margin Requirement (ORMR)	Yes: established annually for all years	0.1/Year LOLE	IESO; NPCC Criteria
NPCC-Québec	12.6%	Reference Margin Level	No: established Annually	0.1/Year LOLE	Hydro Québec; NPCC Criteria
PJM	15.8–15.9%	IRM	Yes: established Annually for each of three future years	0.1/Year LOLE	PJM Board of Managers; ReliabilityFirst BAL-502-RFC-02 Standard
SERC-E	15%[4]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SERC-N	15%	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SERC-SE	15%	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SPP	12%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1/Year LOLE	SPP RTO Staff and Stakeholders

[1] FRCC uses a 15 percent Reference Reserve Margin. FRCC criteria, as approved by the Florida Public Service Commission, is set at 15 percent for nonIOUs and recognized as a voluntary 20 percent Reserve Margin criteria for IOUs; individual utilities may also use additional reliability criteria.

[2] In MISO, the states can override the MISO Planning Reserve Margin

[3] The 20 percent Reference Margin Level is used by the individual jurisdictions in the Maritimes Area with the exception of Prince Edward Island, which uses a margin of 15 percent. Accordingly, 20 percent is applied for the entire area.

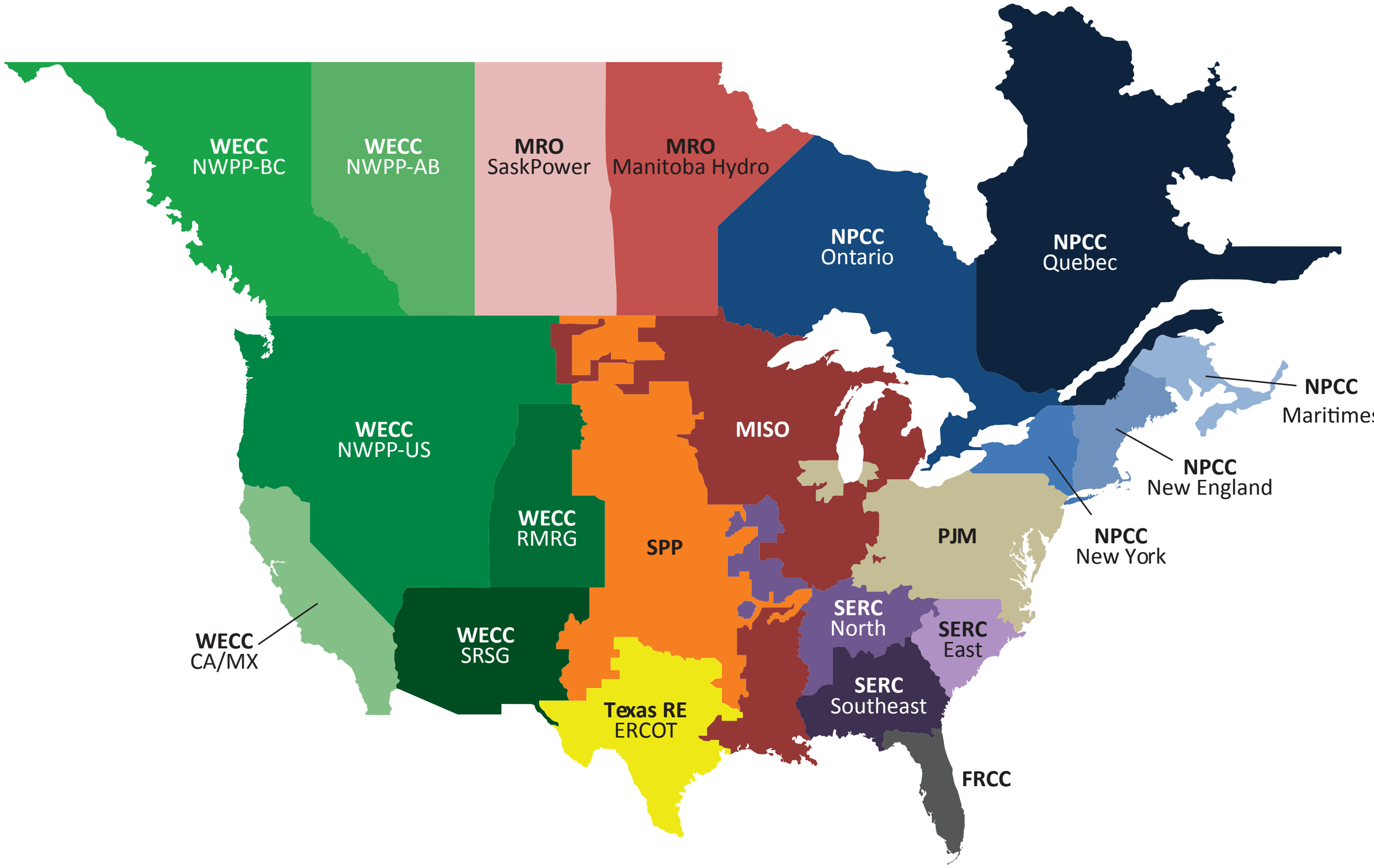
[4] SERC does not provide Reference Margin Levels or resource requirements for its subregions. However, SERC members perform individual assessments to comply with any state requirements.

Table 3.3: Reference Margin Levels for each Assessment Area (2019–2023) (Continued)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
TRE-ERCOT	13.75%	Target Reserve Margin	No	0.1/Year LOLE	ERCOT Board of Directors
WECC-AB	10.14–10.42%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-BC	10.14–10.42%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-CAMX[1]	12.02–12.35%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-NWPP-US	19.56–19.72%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-RMRG	16.07–16.83%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-SRSG	14.07–15.10%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC

[1] California is the only state in the Western Interconnection that has a wide-area Planning Reserve Margin requirement, currently 15 percent.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the eight Regional Entities on an assessment area basis. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Planning Committee, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.



FRCC—Florida Reliability Coordinating Council
- FRCC

MRO—Midwest Reliability Organization
- MRO-SaskPower
- MRO-Manitoba Hydro
- MISO

SPP RE—Southwest Power Pool Regional Entity
- SPP

Texas RE–Texas Reliability Entity
- ERCOT

NPCC—Northeast Power Coordinating Council
- NPCC-New England
- NPCC-Maritimes
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

RF—ReliabilityFirst
- PJM

WECC—Western Electricity Coordinating Council
- WECC-BC
- WECC-AB
- WECC-RMRG
- WECC-CA/MX
- WECC-SRSG
- WECC-NWPP-US

SERC—SERC Reliability Corporation
- SERC-East
- SERC-North
- SERC-Southeast

The following regional assessments were developed based on data and narrative information collected by NERC from the REs on an assessment area basis. The RAS, at the direction of NERC's PC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information. A summary of the key data is provided in **Table D.1**.

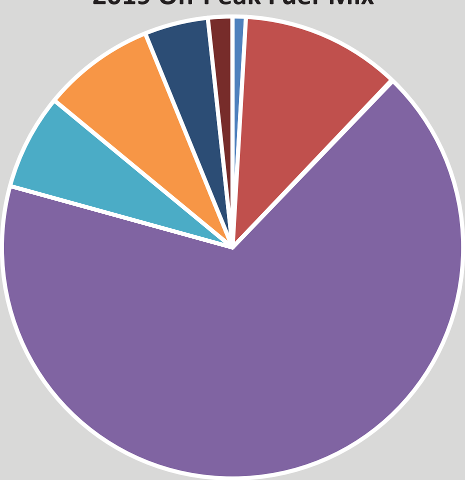
Table D.1: Summary of 2023 Peak Projections by Assessment Area and Interconnection

	Peak Demand (MW)	Annual Net Energy for Load (GWh)	Net Transfers (MW)	Anticipated Capacity Resources	Anticipated Reserve Margin
FRCC	47,144	241,710	1,178	59,083	25.33%
MISO	120,424	679,319	556	140,704	16.84%
MRO-Manitoba	4,336	24,900	125	6,270	44.60%
MRO-Sask	3,977	27,117	100	4,784	20.29%
NPCC-Maritimes	5,245	27,106	0	6,737	28.45%
NPCC-New England	24,317	117,039	81	31,364	28.98%
NPCC-New York	31,414	153,593	1,942	38,558	22.74%
NPCC-Ontario	21,589	133,215	0	25,456	18.62%
PJM	145,885	816,817	0	196,261	34.53%
SERC-E	43,134	218,138	25	52,397	21.48%
SERC-N	40,296	213,861	-952	50,201	24.58%
SERC-SE	46,662	251,006	-1,744	62,418	33.77%
SPP	53,485	271,312	-81	66,935	25.15%
EASTERN INTERCONNECTION	587,908	3,175,132	1,230	741,322	N/A
QUEBEC INTERCONNECTION	37,473	191,567	-145	42,290	12.86%
TEXAS INTERCONNECTION	78,258	422,216	7	85,000	8.62%
WECC-AB	12,321	88,253	0	15,134	22.83%
WECC-BC	12,186	67,068	0	13,920	14.23%
WECC-CAMX	50,201	270,617	0	62,504	24.51%
WECC-NWPP US	50,141	298,914	3,300	62,086	23.82%
WECC-RMRG	13,202	72,988	0	15,993	21.14%
WECC-SRSG	25,712	117,962	0	31,085	20.90%
WESTERN INTERCONNECTION	163,763	915,802	3,300	200,721	N/A

FRCC

The Florida Reliability Coordinating Council's (FRCC) membership includes 30 Regional Entity division members and 22 member services division members composed of investor-owned utilities (IOUs), cooperatives, municipal utilities, power marketers, and independent power producers. FRCC is divided into 10 Balancing Authorities with 36 registered entities (both members and non-members) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards. The Region contains a population of over 16 million people and has a geographic coverage of about 50,000 square miles over Florida.

2019 On-Peak Fuel-Mix



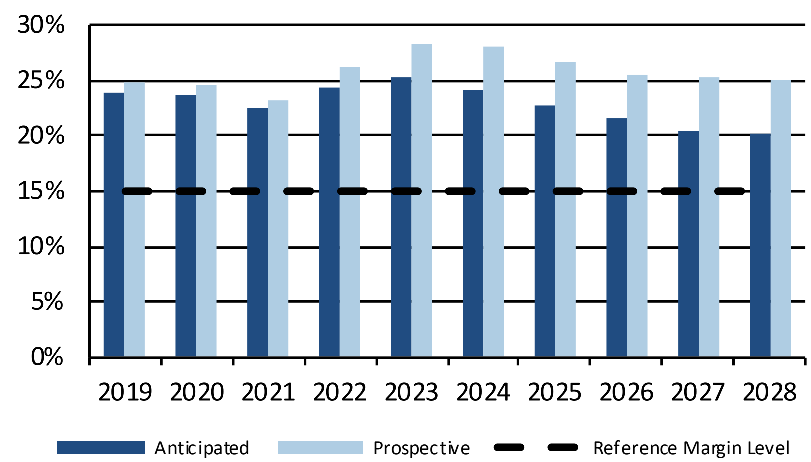
Highlights

- FRCC is not expecting any long-term reliability impacts resulting from fuel supply or transportation constraints. FRCC's planning and operating committees will continue to provide oversight of the regional fuel reliability.
- With the continued addition of natural gas infrastructure into the State of Florida, additional capacity continues to meet actual and projected regional natural gas needs for new generating resources. In addition, studies reviewing key infrastructure outages continue to assess the reliability interdependencies between natural gas and electric facilities as well as actual and projected pipeline capacity requirements, dual-fuel resource capabilities, and operational flexibility of the interconnected pipeline networks.
- FRCC has not identified any other emerging reliability issues. However, FRCC continues to monitor the possible impacts on the long-term reliability of the BES from the changing resource mix, the higher penetration of central station solar generation, and the growing dependency of natural gas.

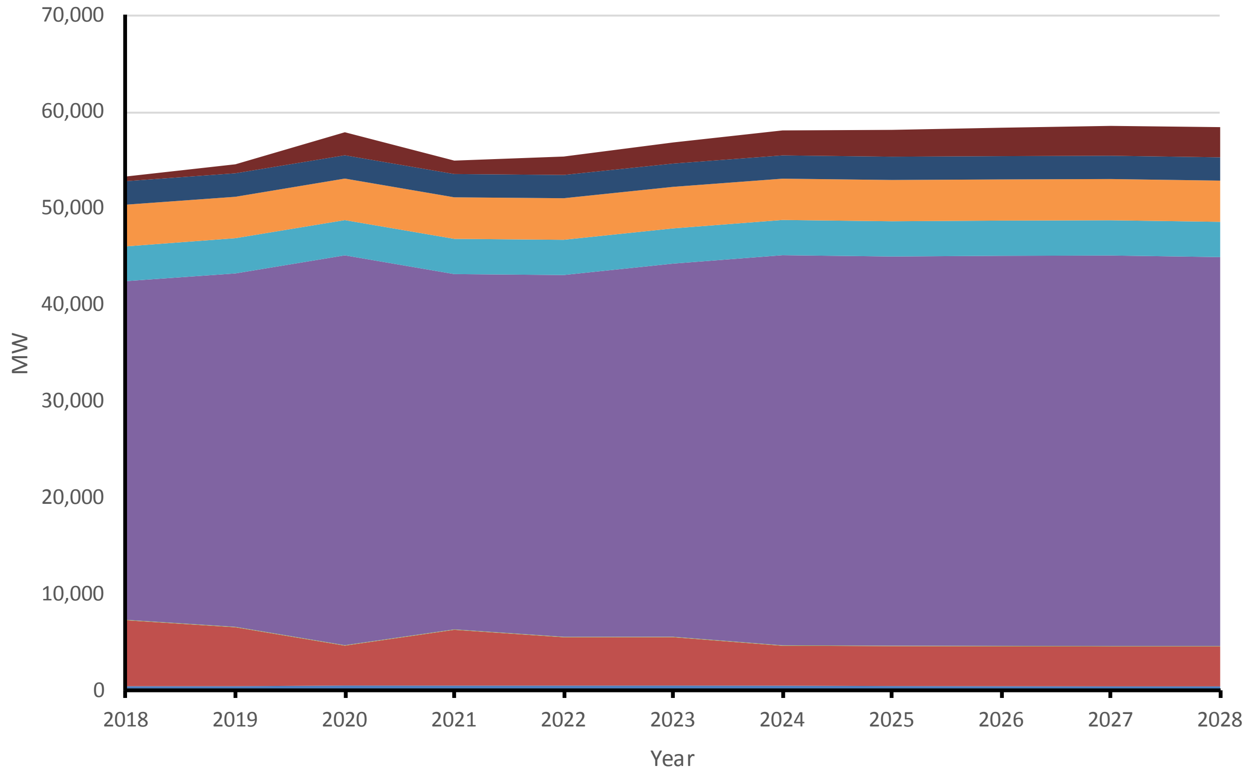
Demand, Resources, and Reserve Margins (MW)

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	48,264	48,739	49,340	49,852	50,374	51,016	51,585	52,205	52,842	52,842
Demand Response	3,047	3,131	3,170	3,199	3,230	3,263	3,295	3,308	3,334	3,334
Net Internal Demand	45,217	45,608	46,170	46,653	47,144	47,753	48,290	48,897	49,508	49,508
Additions: Tier 1	4,259	4,780	5,957	7,945	9,879	10,407	10,617	11,012	11,842	11,876
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	1,452	1,452	1,178	1,203	1,178	1,178	1,178	1,078	1,103	1,103
Existing-Certain and Net Firm Transfers	51,779	51,639	50,609	50,105	49,205	48,866	48,713	48,440	47,825	47,662
Anticipated Reserve Margin (%)	23.93	23.70	22.52	24.43	25.33	24.12	22.86	21.59	20.52	20.26
Prospective Reserve Margin (%)	24.93	24.69	23.26	26.15	28.36	28.10	26.79	25.51	25.37	25.11
Reference Margin Level (%)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	506	1%	489	1%
Coal	6,105	11%	4,136	7%
Hydro	44	0%	44	0%
Natural Gas	40,913	75%	44,576	76%
Nuclear	3,652	7%	3,651	6%
Other	0	0%	0	0%
Petroleum	2,436	4%	2,412	4%
Solar	930	2%	3,129	6%
Total	54,586	100%	58,436	100%



Planning Reserve Margins



FRCC Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	506	566	567	572	574	560	522	504	489	489
Coal	6,105	5,783	5,013	5,013	4,136	4,136	4,136	4,136	4,136	4,136
Hydro	44	44	44	44	44	44	44	44	44	44
Natural Gas	40,913	41,107	41,780	42,955	44,687	44,691	44,594	44,684	44,738	44,576
Nuclear	3,652	3,651	3,651	3,651	3,651	3,651	3,651	3,651	3,651	3,651
Other	0	15	15	15	15	15	15	0	0	0
Petroleum	2,436	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412
Solar	930	1,391	1,908	2,187	2,388	2,588	2,779	2,945	3,095	3,129
Total MW	54,586	54,967	55,388	56,847	57,905	58,095	58,151	58,374	58,564	58,436

Planning Reserve Margins: FRCC uses the Florida Public Service Commission's reliability criterion of a 15 percent reserve margin for nonIOUs as the minimum regional total Reserve Margin based on firm load. FRCC regional total Reserve Margin calculations include merchant plant capacity that are under firm contract to LSEs. FRCC assesses the upcoming ten-year projected summer and winter peak hour loads, generating resources, and firm demand side management (DSM) resources on an annual basis to ensure that the regional total Reserve Margin requirement is projected to be satisfied.

Demand: The individual entities within FRCC assessment area develop their load forecasts, and FRCC then aggregates these forecasts to calculate a non-coincident seasonal peak for the Region. Each entity adjusts their forecasts annually to account for their actual peak demand, updated economic outlook, population growth, weather patterns, conservation and energy efficiency efforts, and electric appliances usage pattern. As a result, firm summer peak demand growth is expected to increase to approximately 1.2 percent when compared to last year's forecasted growth rate of 1.1 percent per year. For firm winter peak load, the average growth rate is also expected to increase to 1.1 percent when compared to last year's forecast of 1.0 percent per year.

Demand-Side Management: Each individual reporting entity develops their own independent forecast of firm controllable and dispatchable DR values forecasted to be available at system peak based on their methodology. These individual reporting entities perform and develop independent analyses of the estimated impacts from the firm DR and load management. FRCC then aggregates those estimated impacts for analytical purposes. Controllable DR from interruptible and dispatchable load management programs within FRCC is treated as a load-modifier and is projected to be constant at approximately 6.3 percent of the summer and winter total peak demands for all years of the assessment period. Some of the larger utilities in the Region account for load profile modifiers, such as DERs and electric vehicles in their forecast. Utilities that do not account for such load profile modifiers in their forecast have not yet experienced a large enough penetration rate of these types of facilities to modify their existing load profiles.

Distributed Energy Resources: In general, DERs are modeled with associated loads and netted out since these loads are implicitly accounted for with the load forecasts of entities within FRCC. Currently, the FRCC assessment area has relatively low penetration levels of DER with modest growth expected throughout the planning horizon. Multiple FRCC subcommittees are reviewing recommendations developed by the FRCC Solar Task Force, which was tasked with examining and determining procedures and processes to address the projected growth of central station solar resources within the assessment area. The FRCC Resource Subcommittee (FRCC-RS) coordinated with the FRCC Load Forecast Working Group (LFWG) to develop a pilot data collection to amalgamate estimated statistics (historical and projected) for DER within the Region to better support integration of DERs into infrastructure sufficiency studies of the transmission and distribution system. While the data for the pilot will be aggregate in nature, FRCC-RS is also actively developing a geographical tracking process to evaluate potential DER growth pockets and continues to coordinate with the FRCC Planning Committee on tractable approaches to such disaggregation in the near future (e.g., substations, zip codes, counties).

Generation: FRCC is not expecting any long-term reliability impacts resulting from an increased reliance on natural-gas-fired generation or from generating plant retirements. Planned (known) future generator retirements are incorporated into the FRCC regional transmission planning process via the studies performed by FRCC subcommittees as part of the annual transmission planning study process. In addition, fuel assurance and reliability continue to be reviewed by the FRCC planning and operating committees and its subgroups. Approximately 2,400 MW of coal, along with 2,700 MW of natural gas, will be retired during the assessment period. FRCC is not expecting any long-term reliability impacts resulting from generating plant retirements.

Capacity Transfers: FRCC has not identified any scenarios that would impact transfers into the FRCC assessment area or would result in reliability issues from reduced transfers. All firm on-peak capacity imports into the FRCC assessment area have firm transmission service agreements in place to ensure deliverability into the assessment area, and these capacity resources are accounted for in the calculation of the assessment area's anticipated Reserve Margin. In addition, the interface owners between the FRCC and SERC assessment areas meet quarterly to coordinate and perform joint studies to ensure the reliability and adequacy of the interface.

Transmission: The FRCC assessment area has not identified any specific major projects that are needed to maintain reliability during the planning horizon. The individual entities do have planned projects that are primarily related to system expansion in order to serve forecasted demand growth, resource integration, or to ensure long-term reliability of the transmission systems. The FRCC assessment area has not identified any transmission constrained areas in its planning studies. The studies performed have shown that the performance of the transmission system is adequate and in compliance with all the requirements in the NERC transmission planning standards for the near-term and long-term planning horizon.

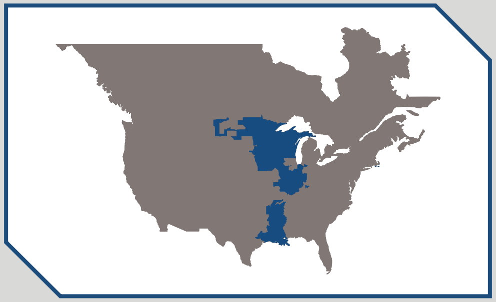
Probabilistic Assessment Overview

- **General Overview:** Sufficient generation resource additions throughout the next ten years result in low LOLH and EUE results for the Base Case study years of 2020 and 2022.
- **Modeling:** FRCC used the tie-line and generation reliability (TIGER) program, which is based on the analytical method of recursive convolution for the computation of LOLH and EUE metrics:
  - FRCC's modeling approach incorporates regional hourly load, generation data, forced outage rates, maintenance schedules, and monthly demand response.
  - Demand response was modeled as a load modifier on a monthly basis with no derates.
  - Solar variable generation resources were modeled at the firm capability available at time of peak. There are no significant wind variable generation resources within the FRCC; therefore, no wind generation was modeled.
  - A load variation Monte Carlo simulation was utilized that provided 500 variations of annual hourly load as an input into TIGER.
  - Based on the results of detailed regional transmission studies, a study model was elected that assumes that all firm capacity resources are deliverable within the FRCC Region. FRCC was modeled as an isolated area with no interconnections with adjacent areas. However, imports were modeled within the FRCC regional generation data and were limited to only firm power purchase agreements.
- **Probabilistic vs. Deterministic:** There are no differences between the reserve margin reported in the LTRA and Probabilistic Assessment (ProbA) Base Case.

Base Case Study

- **Results:** Reserve Margin Levels for the study years are expected to remain above the NERC Reference Margin Level of 15 percent while supporting low LOLH and EUE values. EUE was 0.0003 MWh (2020) and 0.0004 MWh (2022). Projected loss of load only occurred during the summer season.
- **Results Trending:** Comparison of the 2016 and 2018 ProbA analyses show consistent results driven by a sufficient Anticipated Reserve Margin.

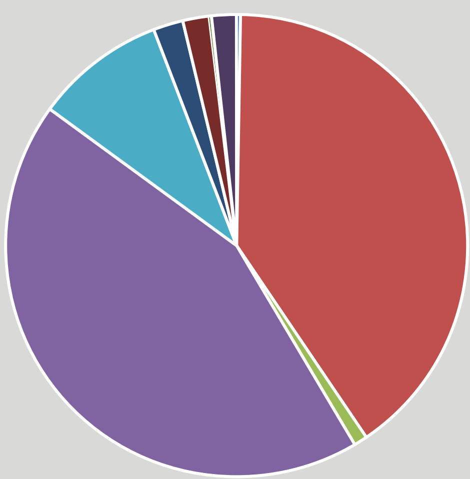
Summary of Results		
Reserve Margin		
	Base Case	
	2020	**2022**
Anticipated	23.7	24.4
Prospective	24.7	26.2
Reference	15.0	15.0
Annual Probabilistic Indices		
	Base Case	
	2020	**2022**
EUE (MWh)	0.00	0.00
EUE (ppm)	0.00	0.00
LOLH (hours/year)	0.00	0.00



MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers the wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authorities and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

2019 On-Peak Fuel-Mix



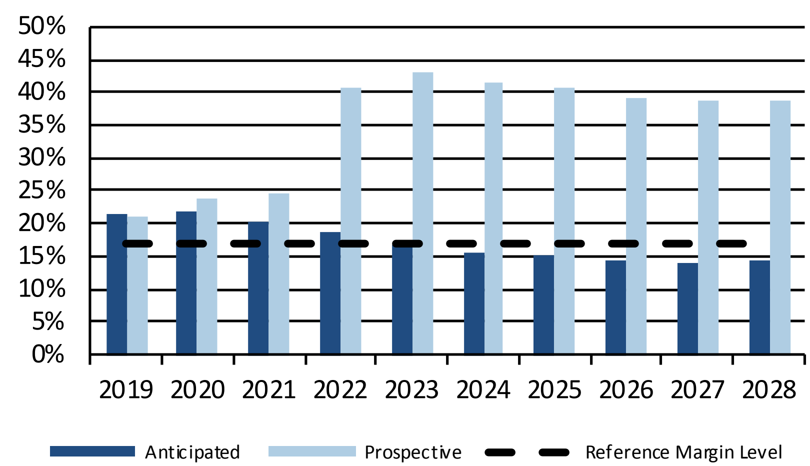
Highlights

- The MISO Region is projected to have resources in excess of the regional requirement. Through 2022, regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements.
- Continued focus on load growth variations and resource mix changes will allow transparency around future resource adequacy risk.
- As MISO continues to operate near the planning reserve margin, it is important to ensure efficient conversion of committed capacity to energy able to serve near term load. MISO has embarked on an initiative called Resource Availability and Need to review gaps in this conversion.

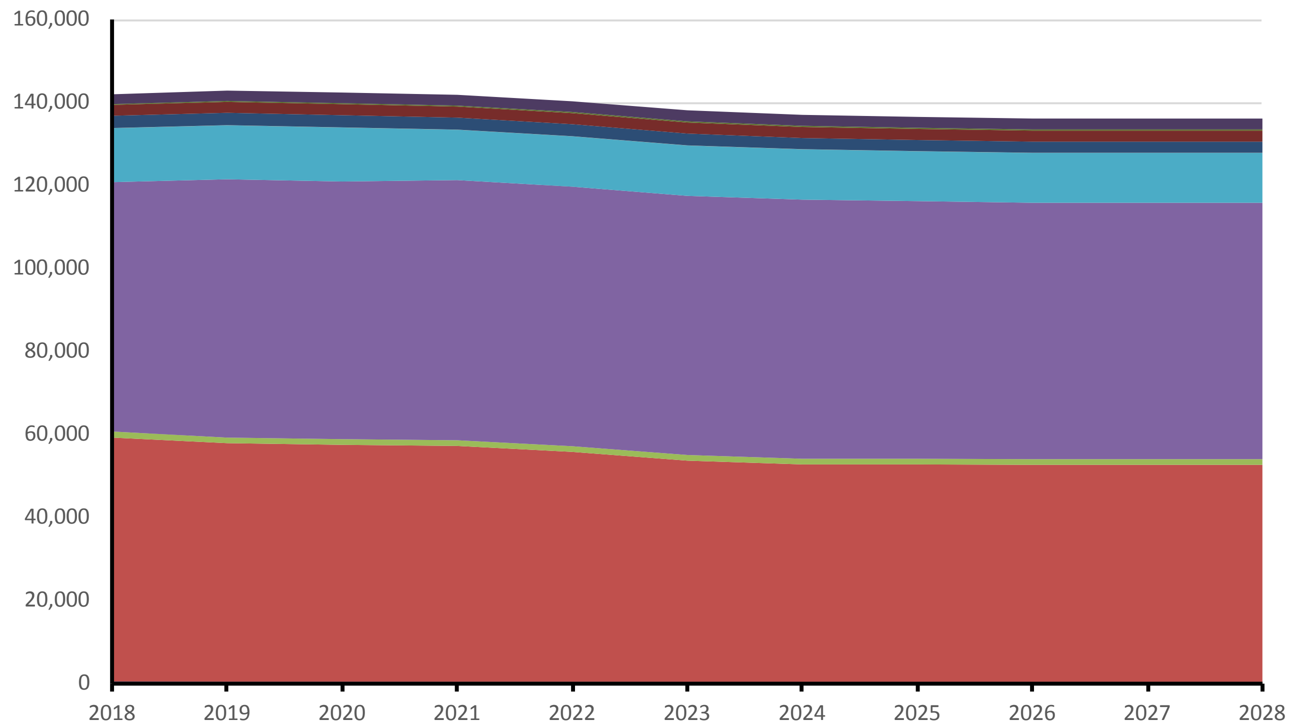
Demand, Resources, and Reserve Margins

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	125,284	125,293	125,636	125,994	126,414	126,779	127,279	127,620	128,217	128,116
Demand Response	5,990	5,990	5,990	5,990	5,990	5,990	5,990	5,990	5,990	5,990
Net Internal Demand	119,294	119,303	119,646	120,003	120,424	120,788	121,289	121,629	122,227	122,126
Additions: Tier 1	2,705	2,866	3,500	3,550	3,640	3,640	3,640	3,640	3,640	3,640
Additions: Tier 2	1,507	5,047	7,671	28,792	33,991	34,016	34,833	34,833	34,833	34,833
Net Firm Capacity Transfers	631	1,064	558	557	556	555	554	553	552	551
Existing-Certain and Net Firm Transfers	141,978	142,304	140,482	139,089	137,064	136,179	135,887	135,589	135,781	136,080
Anticipated Reserve Margin (%)	21.28	21.68	20.34	18.86	16.84	15.76	15.04	14.47	14.07	14.41
Prospective Reserve Margin (%)	20.87	23.71	24.46	40.85	42.88	41.45	40.82	39.30	38.54	38.90
Reference Margin Level (%)	17.10	17.10	17.10	17.10	17.10	17.10	17.10	17.10	17.10	17.10

Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	399	0%	362	0%
Coal	57,509	40%	52,322	38%
Hydro	1,340	1%	1,368	1%
Natural Gas	62,265	44%	61,797	45%
Nuclear	13,025	9%	12,033	9%
Other	20	0%	20	0%
Petroleum	2,974	2%	2,680	2%
Pumped Storage	2,626	2%	2,661	2%
Solar	240	0%	290	0%
Wind	2,491	2%	2,613	2%
Total	142,888	100%	136,146	100%



Planning Reserve Margins



MISO Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	399	399	385	385	362	362	362	362	362	362
Coal	57,509	57,102	56,856	55,419	53,331	52,422	52,422	52,322	52,322	52,322
Hydro	1,340	1,374	1,368	1,368	1,368	1,368	1,368	1,368	1,368	1,368
Natural Gas	62,265	62,099	62,703	62,553	62,455	62,451	62,093	61,797	61,797	61,797
Nuclear	13,025	13,025	12,151	12,151	12,151	12,151	12,033	12,033	12,033	12,033
Other	20	20	20	20	20	20	20	20	20	20
Petroleum	2,974	2,936	2,892	2,892	2,844	2,680	2,680	2,680	2,680	2,680
Pumped Storage	2,626	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,661
Solar	240	240	240	290	290	290	290	290	290	290
Wind	2,491	2,566	2,598	2,572	2,662	2,637	2,622	2,620	2,613	2,613
Grand Total	142,888	142,421	141,872	140,309	138,143	137,041	136,550	136,153	136,146	136,146

Probabilistic Assessment Overview

- **General Overview:** MISO is a summer-peaking system that spans 15 states and consists of 36 local balancing areas that are grouped into 10 local resource zones. For the probabilistic assessment, MISO utilized a multiarea modeling technique for the 10 local resource zones internal to MISO. Firm external imports and nonfirm imports are also modeled. This model and accompanying methodology has been thoroughly vetted through MISO's stakeholder process.
- **Modeling:** Each local resource zone was modeled with an import and export limit based on power flow transfer analysis. In addition to the zone-specific import and export limits, a regional directional limits the North/Central (LRZs 1–7) to South (LRZs 8–10) flow to 3,000 MWs and South to North/Central is limited to 2,500 MWs. The modeling of this limit is the main driver for the difference between the probabilistic and deterministic reserve margins. MISO utilizes unit-specific outage, planning, and maintenance outage rates within the analysis based off of five years of Generation Availability Data System (GADS) data. Modeling unit-specific outage rates increases precision in the probabilistic analysis when compared to the utilization of class average outage rates. Additional assumptions include:
  - Annual peak demand in MISO varies by ±5 percent of forecasted MISO demand based upon the 90/10 percent points of load forecast uncertainty (LFU) distributions.
  - Thermal units in MISO follow a two-state on-or-off sequence based on a Monte Carlo simulation that utilizes EFORd based on five years of GADS data, which is equivalent to derating MISO thermal generating resources by 9.28 percent on average.
  - Hydro units in MISO (except for run-of-river) follow a two-state on-or-off sequence based on Monte Carlo simulation that utilizes EFORd based on five years of GADS data. Run-of-River resources submit three years of historical data at peak (summer months, peak hours 14–17 HE) that is used to determine capacity values.
  - Variable energy resources (wind and solar) in MISO are a load modifier and reduce hourly demand by each individual resources capacity credit that on average is a 15.2 percent capacity credit for wind and a 50 percent capacity credit for solar.
  - Strategic Energy Risk Valuation Model (SERVM) was the software used for the 2018 ProbA. SERVM is a multi-area model that uses multiple load shapes based on historic weather to more accurately capture variance in load shapes, variance in peak load, seasonal load uncertainty, and frequency and duration of severe weather patterns. For the 2018 ProbA, MISO completed 125 iterations of 30 weather years with five levels of economic uncertainty for a total of 18,750 simulations per case.
- **Probabilistic vs. Deterministic:** The LTRA deterministic reserve margins decrement the capacity constrained within MISO South due to the 2,500 MW limit that reflects a decrease in reserve margin. The constraint was explicitly modeled for the probabilistic analysis and determined if sufficient capacity was available to transfer from South to North and vice versa. The modeling of this limitation produces an increase for the probabilistic assessment forecast planning reserve margin.

Base Case Study

- The bulk of the EUE and the LOLH are accumulated in the summer-peaking months with some off peak risk.
- Increasing loss of load statistics are expected with decreasing reserve margins.
- **Results Trending:** Previous results in the 2016 ProbA resulted in 96 MWh EUE and 0.125 hours/year LOLH. The results from this year's analysis resulted in a slight decrease for 2020 when compared to the analysis completed in the 2016 ProbA.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	16.6	21.7	18.9
Reference	15.2	17.1	17.1
ProbA Forecast Operable	10.6	14.2	13.7
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	95.80	14.2	31.6
EUE (ppm)	0.133	0.019	0.043
LOLH (hours/year)	0.125	0.108	0.211

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: As directed under Module E-1 of the MISO Tariff, MISO coordinates with stakeholders to determine the appropriate planning reserve margin for the applicable planning year based upon the probabilistic analysis of the ability to reliably serve MISO coincident peak demand for that planning year. The probabilistic analysis uses a LOLE study that assumes no internal transmission limitations within the MISO Region. MISO calculates the planning reserve margin such that the LOLE for the next planning year is one-day-in-10 years, or 0.1 days per year. The minimum amount of capacity above coincident peak demand in the MISO Region required to meet the reliability criteria is used to establish the planning reserve margin. The planning reserve margin is established as an unforced capacity (planning reserve margin UCAP) requirement based upon the weighted average forced outage rate of all planning resources in the MISO Region. The planning reserve margin increased from the *2017 LTRA* of 15.8 percent to 17.1 percent in the *2018 LTRA*. Changes from 2017–2018 planning year values are due to changes in generation verification test capacity, equivalent forced outage rate demand or equivalent forced outage rate demand with adjustment to exclude events outside management control, new units, retirements, suspensions, and changes in the resource mix.

Demand: MISO does not forecast load for the seasonal resource assessments. Instead, LSEs report load projections under the resource adequacy requirements section (Module E-1) of the MISO tariff. LSEs report their annual load projections on a MISO coincident basis as well as their noncoincident load projections for the next 10 years, monthly for the first two years, and seasonally for the remaining eight years. MISO projects the summer coincident peak demand is expected to grow at an average annual rate of 0.3 percent for the 10 year period, which is the same growth rate from the 2017 assessment.

Demand-Side Management: MISO currently separates DR resources into two categories: direct control load management and interruptible load.[56] Direct control load management is the magnitude of customer service (usually residential). During times of peak conditions or when MISO otherwise forecasts the potential for maximum generation conditions. MISO surveys local BAs to obtain the amount of their demand. For this assessment, MISO uses the registered amount of DSM that is procured and cleared through the annual Planning Resource Auction. MISO forecasts 7,137 MW of direct control load management and interruptible load to be available for the assessment period. MISO also forecasts at least 4,576 MW of behind-the-meter generation to be available for assessment period. Energy efficiency is not explicitly forecasted at MISO; any energy efficiency programs are reflected within the demand and energy forecasts.

Distributed Energy Resources: In 2018, the Organization of MISO State (OMS) conducted a survey to collect DER information.[57] This forecast positions MISO to understand emerging technologies and the role they play in transmission planning as there is a specific case on DERs both at a base case level and increased penetration level. MISO has not experienced any operational challenges as of yet, but as programs grow in the future operational challenges may arise.

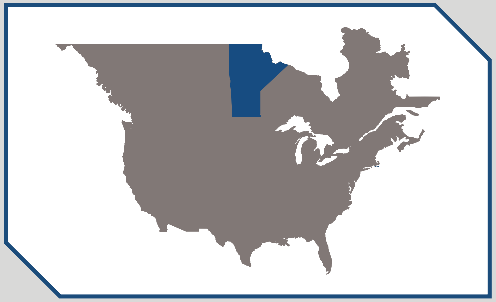
Generation: MISO projects approximately 4.0 GW of generation capacity to retire in 2018. Through the generator interconnection queue and the OMS MISO survey process, MISO anticipates 3.6 GW of future firm capacity additions and uprates along with 7.9 GW of future potential capacity additions to be in-service and expected on-peak during the assessment period. This is based on a snapshot of the generator interconnection queue and the 2018 OMS-MISO survey as of June 2018, which includes the aggregation of active projects.

Capacity Transfers: Interregional planning is critical to maximize the overall value of the transmission system and deliver savings for customers. Interregional studies conducted jointly with MISO's neighboring planning areas are based on an annual review of transmission issues at the seams. Depending on the outcome of those reviews, studies are scoped out and performed. In MTEP, several studies were conducted with both PJM and Southwest Power Pool (SPP).

Transmission: The annual MISO Transmission Expansion Plan (MTEP) proposes transmission projects to maintain a reliable electric grid and deliver the lowest-cost energy to customers in MISO. Major categories of the MTEP include the following: A total of 77 baseline reliability projects required to meet NERC Reliability Standards, 23 generator Interconnection projects required to reliably connect new generation to the transmission grid, one market efficiency project to meet requirements for reducing market congestion, and 248 other projects that include a wide range of projects, such as those that support lower-voltage transmission systems or provide local economic benefit but do not meet the threshold to qualify as market efficiency projects.

[56] See BPM 011 section 4.3 of the MISO Resource Adequacy Business Practice Manual: https://www.misoenergy.org/legal/business-practice-manuals/

[57] http://www.misostates.org/images/Documents/Public_OMS_DER_Survey_Results_as_of_July_31,_2018.pdf



MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to 556,000 customers throughout Manitoba and natural gas service to 272,000 customers in various communities throughout southern Manitoba. The Province of Manitoba is 250,946 square miles. Manitoba Hydro is winter peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

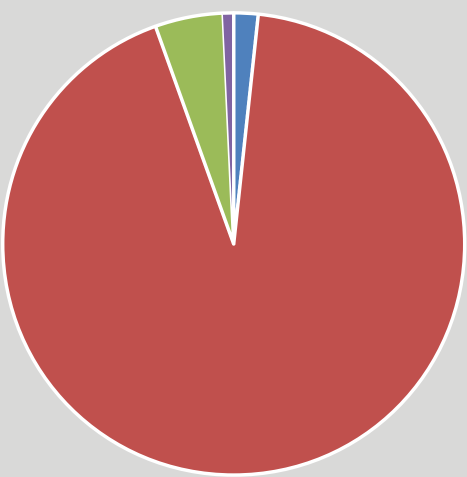
Highlights

- The Anticipated Reserve Margin does not fall below the Reference Margin Level of 12 percent in any year during the assessment period. The 630 MW (net summer addition) Keeyask hydro station is expected to come into service beginning in the winter of 2021/2022, which helps ensure resource adequacy in the latter half and after the end of the current assessment period. No resource adequacy issues are expected.
- Demand is flattening over the LTRA horizon as a result of reduced load growth and EE and conservation efforts.
- The Bipole III HVDC transmission line was put into commercial operation as of July 2018 that improves system reliability and resilience to extreme events.

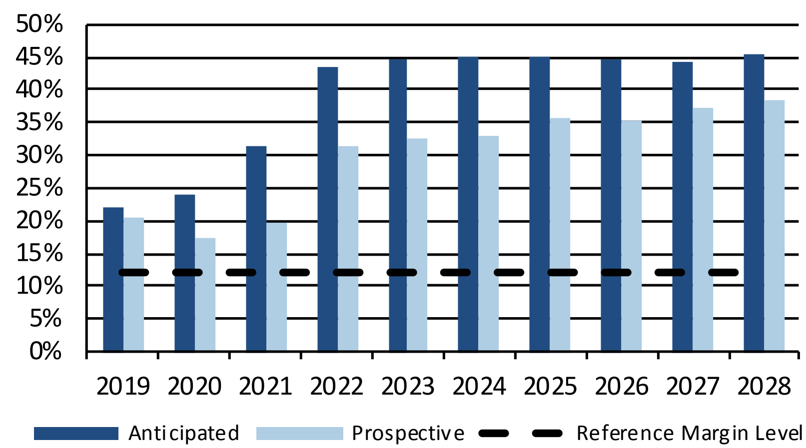
Demand, Resources, and Reserve Margins (MW)

Quantity	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Total Internal Demand	4,524	4,482	4,407	4,370	4,336	4,317	4,293	4,302	4,318	4,357
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,524	4,482	4,407	4,370	4,336	4,317	4,293	4,302	4,318	4,357
Additions: Tier 1	0	0	190	640	640	640	640	640	640	640
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-103	-58	100	125	125	125	100	100	100	100
Existing-Certain and Net Firm Transfers	5,523	5,562	5,609	5,630	5,630	5,630	5,590	5,590	5,590	5,690
Anticipated Reserve Margin (%)	22.09	24.11	31.58	43.48	44.60	45.26	45.11	44.83	44.29	45.30
Prospective Reserve Margin (%)	20.66	17.30	19.60	31.40	32.42	33.03	35.73	35.46	37.27	38.34
Reference Margin Level (%)	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00

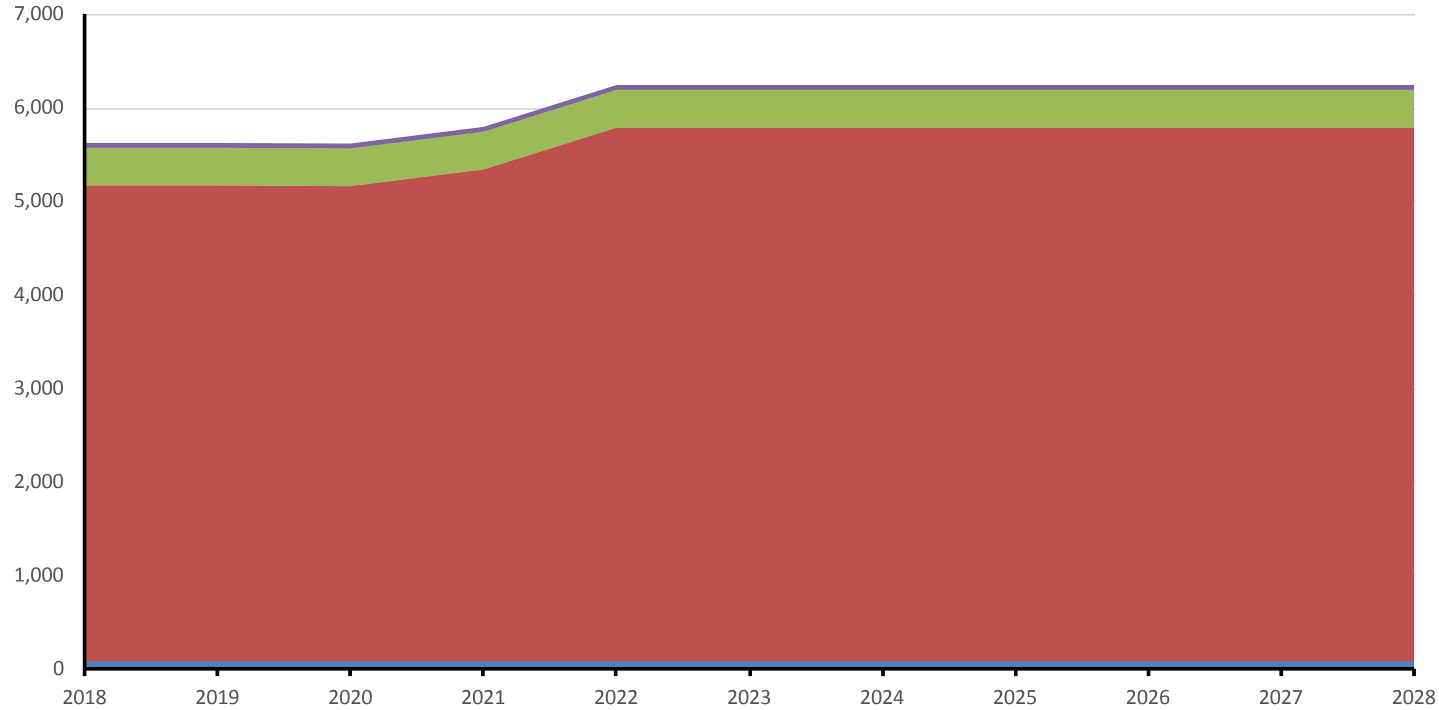
2019 On-Peak Fuel-Mix



Generation Type	2019–20		2028–29	
	MW	Percent	MW	Percent
Coal	93	2%	93	2%
Hydro	5,100	93%	5,710	94%
Natural Gas	261	5%	261	4%
Wind	41	1%	41	1%
Total	5,496	100%	6,106	100%



Planning Reserve Margins



MRO-Manitoba Hydro Fuel Composition

Gen Type	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Coal	92	92	92	92	92	92	92	92	92	92
Hydro	5,079	5,079	5,073	5,251	5,698	5,698	5,698	5,698	5,698	5,698
Natural Gas	403	403	403	403	403	403	403	403	403	403
Wind	52	52	52	52	52	52	52	52	52	52
Total	5,626	5,626	5,620	5,798	6,245	6,245	6,245	6,245	6,245	6,245

Probabilistic Assessment Overview

- **General Overview:** The 2018 Manitoba Hydro ProbA was conducted using the Multi-Area Reliability Simulation program. For 2020 Base Case, small values of EUE and LOLH are observed due to relatively less reserve margin. For 2022 Base Case, the LOLH and EUE are zero.
- **Modeling:** Manitoba Hydro and its neighboring systems are modeled as three areas that consist of Manitoba, Saskatchewan, and the northwest part of MISO. Each of the three interconnected areas is modeled as a copper sheet, and the transmission between areas is modeled with interface transfer limits:
  - Annual peak demand in Manitoba varies by ±5 percent of forecasted Manitoba demand to incorporate uncertainties in peak load forecast. The 8,760 point hourly load records of a typical year were used to model the annual load curve shape.
  - There is a small amount of thermal units representing less than 10 percent of the total installed capacity in Manitoba. These thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation that utilizes 9.25 failures/year and 21.4 hours of average outage duration, which is equivalent to derating Manitoba thermal generating resources by 2.2 percent on average.
  - Manitoba Hydro system is a winter-peaking system, and the vast majority of its generating facilities are use-limited or energy-limited hydro units. All hydro plants are modeled as energy limited based on the historical flow conditions of the river systems.
  - Wind resources in Manitoba are modeled as deterministic load modifiers that consider the seasonal variations that are approximately equivalent to 16 percent and 20 percent of the maximum wind generation capacity for summer and winter seasons, respectively.
- **Probabilistic vs. Deterministic:** Manitoba Hydro is a winter peak system, and the anticipated reserve margins for 2020 and 2022 are taken from the LTRA 2020 and 2022 values, respectively.
  - DR programs are modeled as a simple load modifier by reducing the peak load.
  - Contractual commitments are modeled as load modifiers that consider the contractual obligations of the power sales and purchase agreements.
  - The external systems were modeled in the same detail as the Manitoba system rather than a simple equivalent model. It is assumed that potential assistances from external systems are based on their anticipated reserve margins for 2020 and 2022 planning years.

Base Case Study

- The LOLH and EUE values calculated in this assessment for the reporting year of 2020 is virtually the same as the values obtained in 2016 assessment for the reporting year of 2018. This is expected because of the similarity in modeling assumptions in these two cases. In 2016 assessment, the in-service-date of the expected addition of a new generating station was assumed to be in 2019. In this assessment, however, the in-service-date of the expected addition of the new generating station is assumed to be in 2021. The LOLH and EUE values calculated for the reporting year of 2022 are zero because of the addition of the new generating station and the increase in the transfer capability between Manitoba and the United States due to the addition of the Great Northern Transmission Line between Minnesota and Manitoba.

Summary of Results		
Reserve Margin		
	Base Case	
	2020	**2022**
Anticipated	22.09	31.58
Reference	12	12
ProbA Forecast Operable	14.7	31.0
Annual Probabilistic Indices		
	Base Case	
	2020	**2022**
EUE (MWh)	3259.30	0.0
EUE (ppm)	0.1170	0.0
LOLH (hours/year)	2.39	0.0

Planning Reserve Margins: The Anticipated Reserve Margin does not fall below the Reference Margin Level of 12 percent in any year during the 10-year assessment period. The Reference Margin Level is based on both system historical adequacy performance analysis and reference to probabilistic resource adequacy studies using the index of LOLE and loss of energy expectation (LOEE).

Demand: Manitoba Hydro's load peaks in the winter, typically in the months of January, February, or December. The primary driver of energy load growth in Manitoba is population (1.1 percent anticipated population growth) with the secondary driver being the economy. Manitoba Hydro uses econometric regression modeling by sector to determine projected energy usage. Subregional load growth projections are utilized for five areas to assist in sub-regional transmission planning.

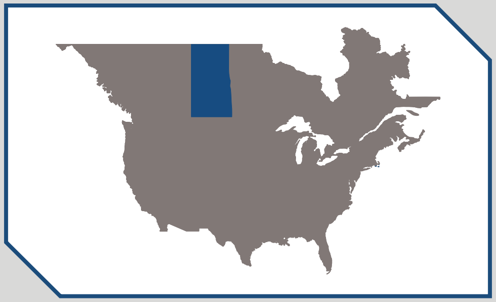
Demand-Side Management: Manitoba Hydro does not have any DSM resources that are considered as controllable and dispatchable DR. Manitoba Hydro does have energy efficiency and conservation initiatives used to reduce overall demand in the assessment area, and the impact of the reductions are included in the load forecast.

Distributed Energy Resources: There is about 31 MW dc of solar DERs in Manitoba as of the end of April 2018. Most of the solar distributed resources were installed in the last year under an incentive program that has ended. Even with high growth rates, Manitoba Hydro is not anticipating the quantity of solar DERs in Manitoba would increase to a level that would cause potential operation impacts in the next five to 10 years.

Generation: The 630 MW (net summer addition) Keeyask hydro station is anticipated to come into service beginning in the winter of 2021/2022, which will help promote resource adequacy in the latter years of the assessment period and support a related 250 MW capacity transfer into MISO. The only unit currently impacted by environmental requirements is Brandon Unit 5 (coal), which is categorized as an unconfirmed retirement at the end of 2019. The driver of the potential retirement of Brandon Unit 5 is both environmental and end of lifespan. No adverse effect on reliability is anticipated as a result of the potential retirement as this unit is currently planned to be converted into a synchronous condenser for area voltage support once the coal-fired boiler is retired.

Capacity Transfers: The Manitoba Hydro system is interconnected to the MISO Zone 1 local resource zone (which includes Minnesota and North Dakota), which is summer-peaking as a whole. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts but only if the following conditions simultaneously occur: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint. The additional hydro generation and the related 250 MW capacity transfer into the MISO Region will tend to increase north to south flows on the Manitoba-MISO interface. A 100 MW capacity transfer from Manitoba to Saskatchewan will tend to increase east to west flow on the Manitoba-Saskatchewan interface. Manitoba Hydro has coordination and tie-line agreements with neighboring assessment areas, such as MISO, SaskPower, and IESO. In accordance with these agreements, planning and operating related issues are discussed and coordinated through respective committees.

Transmission: There are several major enhancements to the transmission system that are projected to come on-line during the assessment period. Most of the projects are dictated by the need to expand the transmission system to reliably serve growing loads, transmit power to the export market, improve safety, improve import capability, increase efficiency, and connect new generation. The most significant of the major system enhancements is the addition of the third bipolar high voltage direct current transmission system to improve reliability, especially during extreme events; this is now in commercial operation as of July 2018. In 2021, the new outlet transmission facilities for the Keeyask Generating Station are due to begin commercial operations. Manitoba Hydro is expecting a new 500 kV interconnection from Dorsey to Iron Range (Duluth, Minnesota) to come into service in 2020. A new 230kV transmission interconnection between Birtle, Manitoba and Tantallon, Saskatchewan is expected to be in-service in June 2021. In 2022 a new transmission line from Laverendrye to St. Vital is expected to go into service in order to upgrade the 230 kV network in the Winnipeg area into a 230kV ring to protect against extreme events.



Highlights

- Anticipated reserve margins will remain above the Reference Margin Level (11 percent) throughout the assessment period.
- Approximately 1,772 MW of additional renewal capacity is projected over the assessment period. The expected on-peak contribution from renewables is projected to increase from 22 percent in 2018 to 27 percent in 2028.
- A new 230 kV tie line with Manitoba Hydro is under construction to facilitate a 100 MW firm capacity /energy transfer.

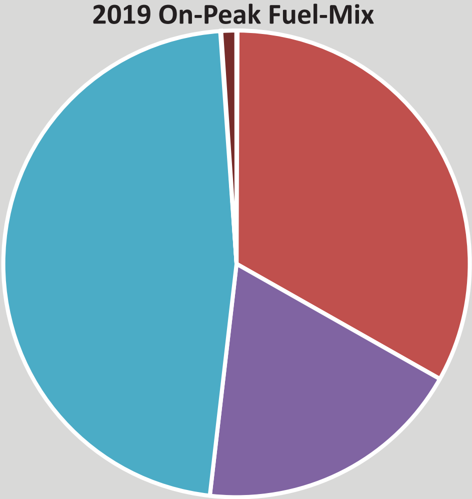
MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System and its interconnections.

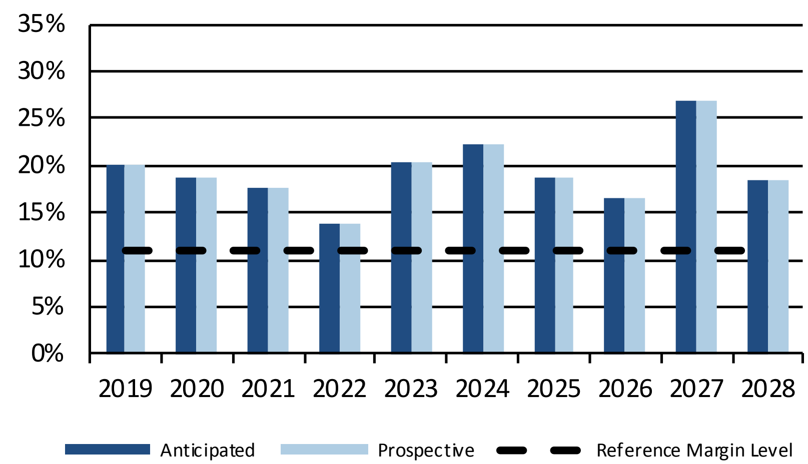
Demand, Resources, and Reserve Margins (MW)

Quantity	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Total Internal Demand	3,924	3,973	3,998	4,032	4,062	4,083	4,135	4,169	4,206	4,231
Demand Response	85	85	85	85	85	85	85	85	85	85
Net Internal Demand	3,839	3,888	3,913	3,947	3,977	3,998	4,050	4,084	4,121	4,146
Additions: Tier 1	354	361	396	436	826	866	906	946	1,336	1,376
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	25	25	125	100	100	100	100	100	100	100
Existing-Certain and Net Firm Transfers	4,257	4,257	4,209	4,053	3,958	4,018	3,898	3,815	3,894	3,529
Anticipated Reserve Margin (%)	20.12	18.78	17.68	13.74	20.29	22.15	18.64	16.58	26.92	18.34
Prospective Reserve Margin (%)	20.12	18.78	17.68	13.74	20.29	22.15	18.64	16.58	26.92	18.34
Reference Margin Level (%)	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00

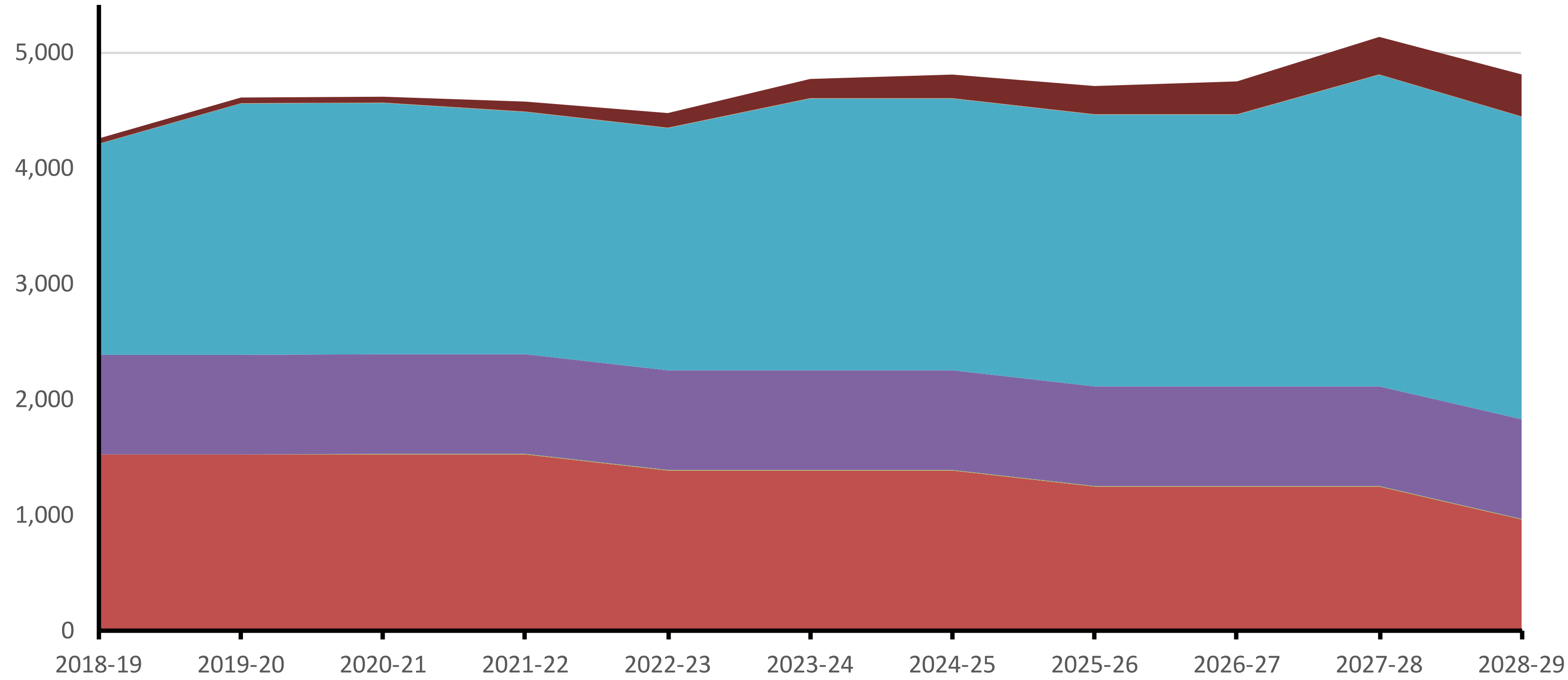
2019 On-Peak Fuel-Mix



Generation Type		2019–20		2028–29	
		MW	Percent	MW	Percent
Biomass		3	0%	3	0%
Coal		1,531	33%	1,253	24%
Geothermal		0	0%	5	0%
Hydro		862	19%	862	17%
Natural Gas		2,173	47%	2,695	52%
Other		3	0%	3	0%
Solar		0	0%	0	0%
Wind		49	1%	324	6%
Total		4,620	100%	5,144	100%



Planning Reserve Margins (Winter)



MRO-SaskPower Fuel Composition

Gen Type	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Biomass	3	3	3	3	3	3	3	3	3	3
Coal	1,531	1,531	1,531	1,392	1,392	1,392	1,253	1,253	1,253	968
Geothermal		5	5	5	5	5	5	5	5	5
Hydro	862	862	862	862	862	862	862	862	862	862
Natural Gas	2,173	2,173	2,096	2,096	2,351	2,351	2,351	2,351	2,695	2,617
Other	3	3	3	3	3	3	3	3	3	3
Solar		0	0	0	0	0	0	0	0	0
Wind	49	51	86	126	166	204	244	284	324	363
Total	4,620	4,627	4,584	4,485	4,780	4,818	4,719	4,759	5,144	4,820

Probabilistic Assessment Overview

- **General Overview:** Based on the deterministic calculations within this assessment, Saskatchewan's anticipated reserve margin is 20.1 percent and 17.7 percent for year 2020 and 2022, respectively. EUE calculated for the Base Case is 1147.5 MWh/yr and 4494.9 MWh/yr for the year 2020 and 2022, respectively. LOLH follows a similar pattern to EUE.
- **Modeling:** SaskPower utilizes the Multi-Area Reliability Simulation (MARS) program for reliability planning and case runs. The software performs the Monte Carlo simulation by stepping through the time chronologically and calculates the standard reliability indices of daily and hourly LOLE and EUE. Detailed representation of the utility system, such as load forecast, expansion sequence, unit characteristics, maintenance and outages is included in the model. The model simultaneously considers many types of randomly occurring events, such as forced outages of generating units. The program also calculates the need for initiating emergency operating procedures (EOPs):
    - This reliability study is based on the 50/50 load forecast that includes data like the annual peak, annual target energy, and load profiles. The model distributes the annual energy into hourly data based on the load shape. Saskatchewan develops energy and peak demand forecasts based on provincial econometric model, forecasted industrial load data, and weather normalization model. The forecasts also take into consideration of the Saskatchewan economic forecast, historic energy sales, customer forecasts, weather normalized sales, and system losses.
    - Generating unit forced outage and partial outages are modeled in MARS by inputting a multi-state outage model that represents an equivalent forced outage rate (EFOR) for each unit represented. MARS models capacity unavailability by considering the average and partial outages for each generating unit that has occurred over the most recent five-year period. Forced outages are modeled as two- or three-state models. Natural gas units are typically modeled as a two-state unit so that a natural gas unit is either available to be dispatched up to full load or is on a full forced outage with zero generation. Coal facilities are typically modeled as three-state units. A coal unit can be in a full load, a derated forced outage, or a full forced outage state.
    - For reliability planning purposes, Saskatchewan plans for 10 percent of wind nameplate capacity to be available to meet summer peak and 20 percent of wind nameplate capacity to be available to meet winter peak demand.
    - Hydro generation is modeled as an energy limited resource and utilized based on deterministic scheduling on a monthly basis. Hydro units are described by specifying maximum rating, minimum rating, and monthly available energy. The first step is to dispatch the minimum rating for all the hours in the month. Remaining capacity and energy is then scheduled so as to reduce the peak loads as much as possible.
    - DSM is deducted from the load forecast (both the peak load and energy forecasts). Demand response is modelled as an emergency operating procedure by assigning a fixed capacity value.
- **Probabilistic vs. Deterministic:** Reserve margin results for probabilistic assessment is consistent with deterministic assessment.

Base Case Study

- Saskatchewan has planned for adequate resources to meet anticipated load and reserve requirements for the assessment period.
- The major contribution to the LOLH and EUE is in the month of October (> 60 percent) due to maintenances scheduled for some of the largest units. Most of the maintenance is scheduled during off-peak periods and can be rescheduled to mitigate short-term reliability issues.

Results Trending: Since the 2016 ProbA, the reported forecast reserve margin has dropped from 25.6 percent to 20.1 percent. This is mainly due to deferral of Wind-Chaplin (177 MW), Biomass-MLTC (36 MW), and Flare Gas (20 MW) generation projects.

Summary of Results			
Reserve Margin			
	2020*	**2020**	**2022**
Anticipated	25.6	20.1	17.7
Reference	11.0	11.0	11.0
ProbA Forecast Operable	22.5	15.7	11.7
Annual Probabilistic Indices			
	2020*	**2020**	**2022**
EUE (MWh)	65.5	1147.5	4494.9
EUE (ppm)	2.6	43	167
LOLH (hours/year)	0.84	11.45	39.02

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: SaskPower uses a criterion of 11 percent as the Reference Reserve Margin for resource adequacy. Saskatchewan has assessed its planning reserve margin for the upcoming ten years while considering the summer and winter peak hour loads, available existing and anticipated generating resources, firm capacity transfers, and DR for each year. Saskatchewan's anticipated reserve margin ranges from approximately 14 to 27 percent and does not fall below the Reference Margin Level.

Demand: SaskPower's system peak forecast is contributed by econometric variables, weather normalization, and individual level forecasts for large industrial customers. Average annual summer and winter peak demand growth is expected to be approximately one percent throughout the assessment period.

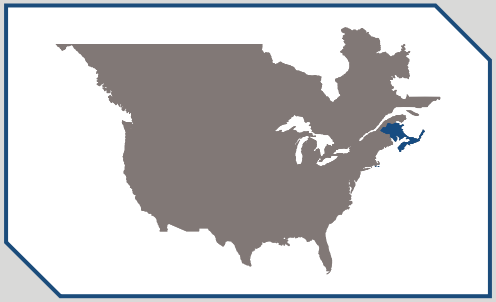
Demand-Side Management: SaskPower's energy efficiency and energy conservation programs include incentive-based and education programs focusing on installed measures and products that provide verifiable, measureable and permanent reductions in electrical energy, and demand reductions during peak hours. Energy provided from EE and DSM programs are modeled as load modifiers and are netted from both the peak load and energy forecasts. A steady growth is expected on energy efficiency and conservation over the assessment period. SaskPower's DR program has contracts in place with industrial customers for interruptible load based on defined DR programs. The first of these programs provides a curtailable load, currently up to 85 MW, with a 12 minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours notification time.

Distributed Energy Resources: The penetration level of DERs is currently very low (approximately 14 MW), and therefore, SaskPower does not anticipate operational challenges due to the DERs. The current penetration of DER Solar PV is approximately 0.3 percent of the total load. It is estimated that the penetration would increase to approximately 1.7 percent in the five-year horizon.

Generation: SaskPower is planning to add a total of 2,822 MW (name plate capacity) generation including 1,607 MW of wind, 1,050 MW of natural gas, and 100 MW of firm import. The addition of wind may require curtailing the generation, or have additional fast ramping capacity available from other resources, such as natural gas facilities, to follow the intermittency of the variable resource. SaskPower is not expecting long-term reliability impacts due to increased reliance on natural gas. A total of approximately 833 MW of generation is expected to be retired, which includes 254 MW of natural gas facilities and 562 MW of coal facilities. Replacement resources are being planned before the retirements, and therefore SaskPower is not expecting any long-term reliability impacts due to generation retirements.

Capacity Transfers: Saskatchewan has a contract in place for a firm 25 MW (until March 2022) and a firm 100 MW (starting Summer 2021 and throughout the assessment period) capacity transfers from Manitoba Hydro, including supply source and transmission. A new 230 kV tie-line between Manitoba and Saskatchewan is currently under construction to facilitate the 100 MW capacity transfer. From a capacity and transmission reliability perspective, Saskatchewan has coordinated with Manitoba Hydro to ensure that the capacity transfer is correctly modelled in on-going operational and planning studies. Any planning or operating related issues are coordinated in accordance with the interconnection agreements through respective planning and operating committees between SaskPower and Manitoba Hydro.

Transmission: Saskatchewan has several major transmission projects during the one to five year planning horizon of the assessment period. These projects are driven by load growth and reliability needs and involve the construction of approximately 330 km of 230 kV and 200 km of 138 kV new transmission lines.



NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC subregion that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million people.

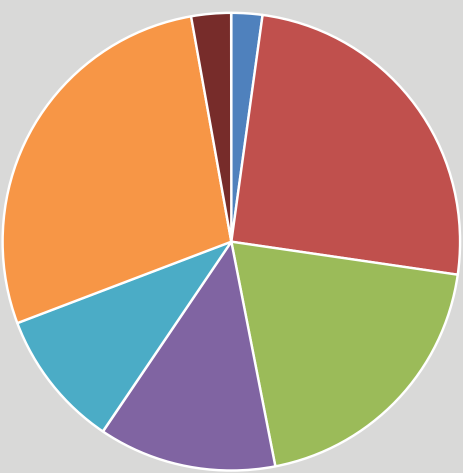
Highlights

- Demand growth is effectively negligible over the duration of the LTRA analysis period.
- An undersea HVDC undersea cable connection to the Canadian province of Newfoundland and Labrador was completed in late 2017. This will allow for the mid-2020 retirement of a 153 MW coal-fired generator with an equivalent amount of firm hydro capacity imported through the cable.

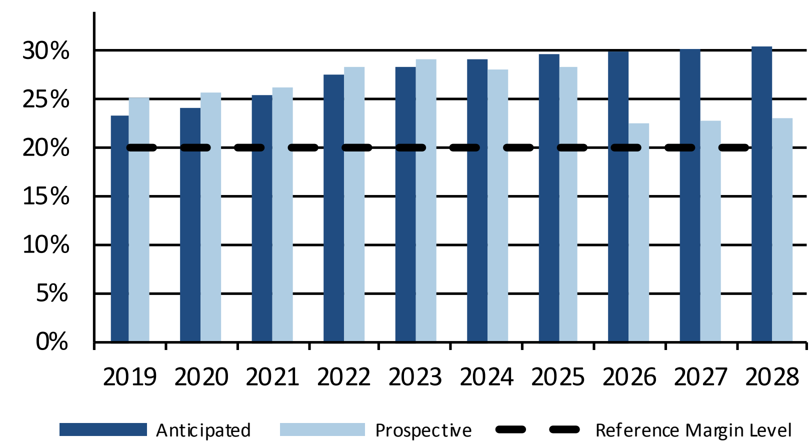
Demand, Resources, and Reserve Margins (MW)

Quantity	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Total Internal Demand	5,595	5,603	5,583	5,545	5,508	5,480	5,454	5,445	5,434	5,429
Demand Response	265	264	264	264	264	263	263	263	262	262
Net Internal Demand	5,330	5,339	5,319	5,281	5,245	5,217	5,191	5,182	5,172	5,167
Additions: Tier 1	48	59	95	95	95	95	95	95	95	95
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-110	-69	-66	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	6,532	6,573	6,576	6,642	6,642	6,642	6,642	6,642	6,642	6,642
Anticipated Reserve Margin (%)	23.46	24.22	25.41	27.56	28.45	29.13	29.78	30.01	30.26	30.39
Prospective Reserve Margin (%)	25.16	25.74	26.22	28.35	29.21	28.01	28.35	22.70	22.94	23.06
Reference Margin Level (%)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00

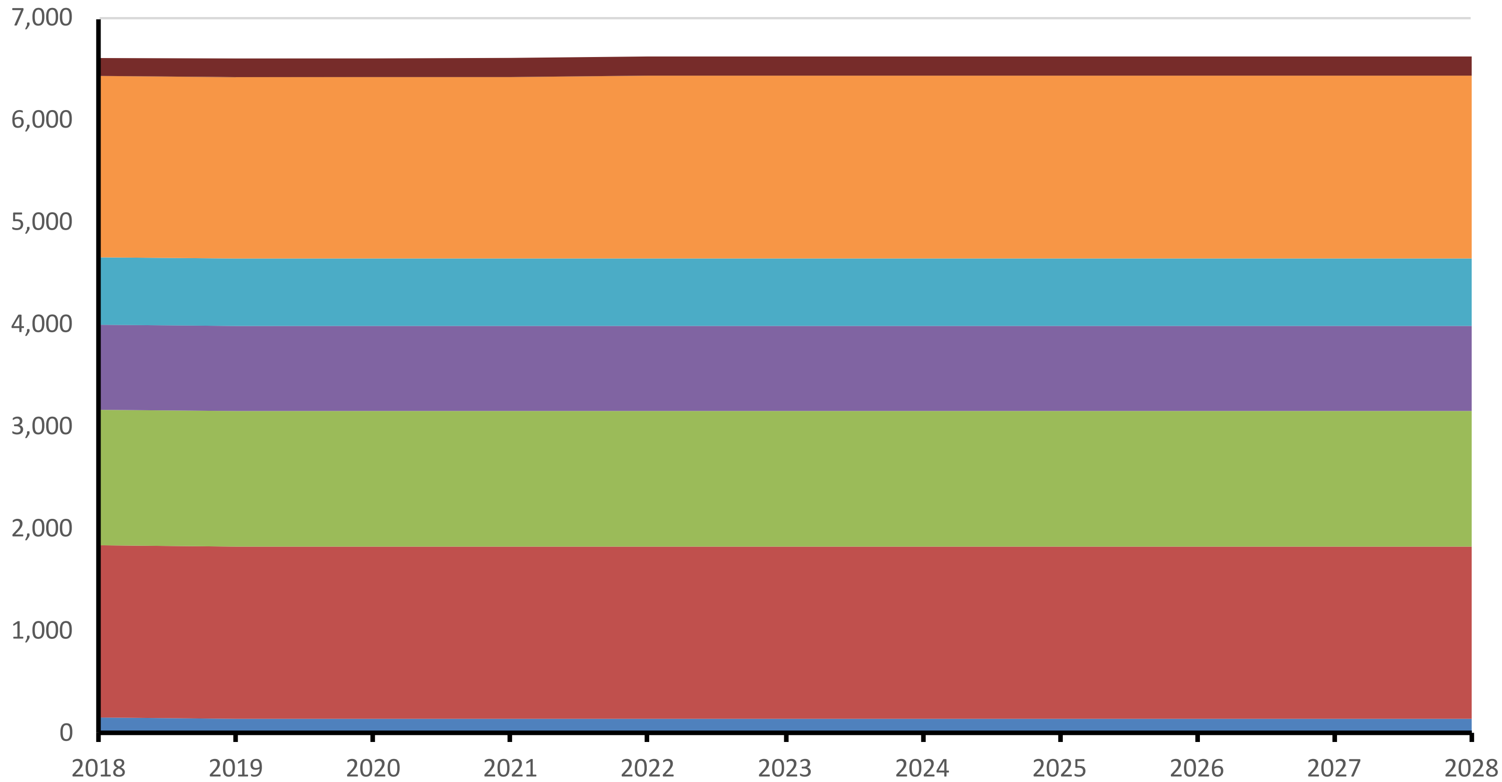
2019 On-Peak Fuel-Mix



Generation Type	2019–2020		2028–2029	
	MW	Percent	MW	Percent
Biomass	148	2%	148	2%
Coal	1,700	25%	1,700	25%
Hydro	1,327	20%	1,328	20%
Natural Gas	850	13%	850	13%
Nuclear	660	10%	660	10%
Petroleum	1,893	28%	1,911	28%
Solar	0	0%	0	0%
Wind	190	3%	195	3%
Total	6,768	100%	6,791	100%



Planning Reserve Margins (Winter)



NPCC-Maritimes Fuel Composition

Gen Type	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Biomass	148	148	148	148	148	148	148	148	148	148
Coal	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
Hydro	1,327	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328
Natural Gas	850	850	850	850	850	850	850	850	850	850
Nuclear	660	660	660	660	660	660	660	660	660	660
Petroleum	1,893	1,893	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911
Solar	0	0	0	0	0	0	0	0	0	0
Wind	190	195	195	195	195	195	195	195	195	195
Total	6,768	6,773	6,791	6,791	6,791	6,791	6,791	6,791	6,791	6,791

Probabilistic Assessment Overview

- **General Overview:** The Maritimes area is a winter-peaking area with separate jurisdictions and regulators in New Brunswick, Nova Scotia, Prince Edward Island (PEI), and Northern Maine. No significant LOLH was observed. The estimated EUE is negligible. The anticipated reserve margins are well above 20 percent in both years. Any contribution to the LOLH and EUE occur during the peak (winter) monthly period.
- **Modeling:** Assumptions used in this ProbA are consistent with those used in NPCC 2018 Long Range Adequacy Overview.[1] The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures as prescribed by the NPCC resource adequacy criterion:[2]
    - Maritimes area demand is the maximum of the hourly sums of the individual sub-area load forecasts. Except for the Northern Maine subarea that uses a simple scaling factor, all other subareas use a combination of some or all of efficiency trend analysis, anticipated weather conditions, econometric modelling, and end use modeling to develop their load forecasts.
    - Combustion turbine capacity for the Maritimes area is seasonal dependable maximum net capability. During summer, these values are derated accordingly.
    - Hydro capacity in the Maritimes area is predominantly run of the river, but enough storage is available for full rated capability during daily peak load periods.
    - Solar capacity in the Maritimes area is behind-the-meter and netted against load forecasts. It does not currently count as capacity.
    - The Maritimes area provides an hourly historical wind profile for each of its four subareas based on actual wind shapes from the fiscal year of 2011/2012. The data is considered typical.
- **Probabilistic vs. Deterministic:** Details regarding the differences between the probabilistic and deterministic representations can be found in the *NERC 2018 Probabilistic Assessment – NPCC Region*.[3]
    - The loads for each area were modeled on an hourly, chronological basis. It was based on the 2002 load shape for the summer period and the 2003/04 load shape for the winter period.[4]
    - The Maritimes area modeled operating procedures that included reduced operating reserves before firm load has to be disconnected.
    - Demand response in the Maritimes area is currently comprised of contracted interruptible loads.
    - Transmission additions and retirements assumed were consistent with this *NERC 2018 Long-Term Reliability Assessment*.
    - In the NPCC ProbA simulations, all areas received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously in all areas and subareas.

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1 https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

2 https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

3 Available December 2018 at the follow: https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

4 https://www.npcc.org/Library/Other/Forms/Public20List.aspx

- **Results Trending:** The previous study *NERC Probabilistic Assessment – NPCC Region* estimated an annual LOLH = 0.000 hours/year and a corresponding EUE equal to 0.0 (ppm) for the year 2020.* The 2020 Forecast 50/50 peak demand forecast is lower in this assessment than reported in the previous assessment; Forecast capacity resources are approximately the same as compared to the previous assessment. No material difference in estimated LOLH and EUE is observed between the two assessments.

Summary of Results			
Reserve Margin			
	2020*	**2020**	**2022**
Anticipated	24.4	23.5	25.4
Reference	20.0	20.0	20.0
ProbA Forecast Operable	18.1	33.0	33.5
Annual Probabilistic Indices			
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: The Anticipated Reserve Margin does not fall below the Reference Margin Level of 20 percent during the 10-year assessment period.

Demand: Maritimes area peak loads are expected to increase by 3.2 percent during the summer but decline by 1.1 percent during the winter over the 10-year assessment period. This translates to average growth rates of 0.3 percent in summer and -0.1 percent in winter. Rural to metropolitan population migration and the introduction of split-phase heat pump technology to areas traditionally heated by fossil fuels has created load growth for the southeastern corner of New Brunswick (NB) that has outpaced growth in the rest the Maritimes Area in recent years. It is expected that these effects will level off in the future.

Demand-Side Management: Plans to develop up to 150 MW by 2026/27 of controllable direct load control programs that use smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist.[58] During the assessment period, annual amounts for summer peak demand reductions associated with energy efficiency programs rise from seven MW to 92 MW while the annual amounts for winter peak demand reductions rise from 51 MW to 541 MW.[59]

Distributed Energy Resources: The current amount of DERs in the NB subarea is insignificant (<5 MW). Should these amounts increase to significant levels, NB will consider adding DERs to its load forecasting and resource planning processes and give due consideration to ramping and/or light load issues. Nova Scotia (NS) projects 203 MW of directly metered[60] installed DG by 2020. Real-time data is not available for all these sites, which may present operational challenges once all projects are in-service. The situation will be monitored as these projects are phased-in and methods to increase their visibility will be investigated.

[58] The savings for these programs were included as energy efficiency and conservation on the LTRA Form A sheets and will be broken out once the program designs are better understood.

[59] Current and projected energy efficiency effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

[60] Not netted against the load forecast.

Generation: Small amounts of new generation capacity are being installed to introduce alternative renewable energy resources into the capacity mix. Renewable electricity standards have led to the development of substantially more wind generation capacity than any other renewable generation type. In NS, the renewable electricity standard target for 2017 calls for 25 percent of energy sales to be supplied from renewable resources. This target increases to 40 percent of energy sales from renewable resources in 2020. Currently the 25 percent target is being met primarily by wind generation, hydro, and biomass.[61]

Capacity Transfers: Probabilistic studies show that the Maritimes Area is not reliant on interarea capacity transfers to meet NPCC resource adequacy criteria.

Transmission: Installation of two undersea 138 kV cable connections, each with a capacity of 200 MVA and a length of nine miles, was completed during the first week of July in 2017 and increases capacity and improves the ability to withstand transmission contingencies in the area between NB and Prince Edward Island (PEI). Associated with this project is the addition of a new 138 kV overhead line in NB to the new cable terminus during the fall of 2017 and on Island transmission reconfigurations that will also further increase capacity to the island by October 2018. A 475 MW +/-200 kV high voltage direct current undersea cable link (Maritime Link) between Newfoundland and Labrador and NS will be installed by late 2017. This cable in conjunction with the construction of the Muskrat Falls hydro development in Labrador is expected to facilitate the unconfirmed retirement of a 153 MW coal-fired unit in NS by mid-2020. The Maritime Link could also potentially provide a source for imports from NS into NB that would reduce transmission loading in the southeastern NB area. In addition, during the fall of 2018, a second 345/138 kV transformer will be added in parallel with an existing transformer at the Keswick terminal in NB to mitigate the effects of transformer contingencies at the terminal.

[61] The incremental renewable requirements of the 40 percent target will largely be met by the energy import from the Muskrat Falls hydro project in Newfoundland and Labrador.

NPCC-New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system and also administers the area's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.

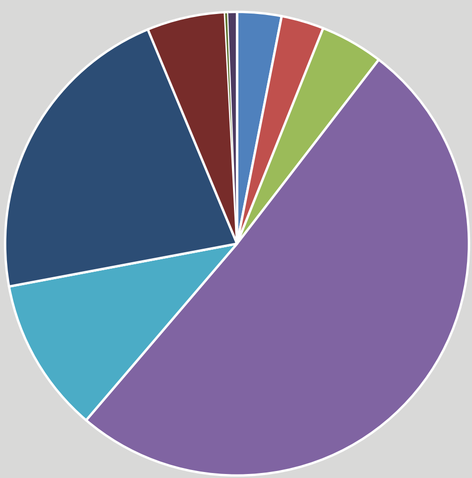
Highlights

- ISO-NE projects sufficient Anticipated Reserve Margins for the entire 2018 LTRA assessment period.
- The Region's most pressing reliability challenge is fuel security or the possibility that the Region's generators will not have, or be able to obtain, the fuel they need to run, particularly during extended cold weather (or other stressed system) conditions.
- ISO-NE is currently engaged with regional stakeholders, including the states, to develop long-term solutions to address the increasing fuel-security challenges facing the Region.
- Coordinating the timing of resource retirement and additions will also be challenging.
- The ISO is forecasting more than 5,000 MW of solar resources to be built during the 2018 LTRA assessment period and has developed solar forecasting tools to help successfully integrate these resources into both planning and operations. At this time, ISO-NE anticipates having adequate fast-start and load-following resources available to accommodate the variability of intermittent resources.
- New England's transmission system is robust, and transmission projects are planned or under construction to meet reliability needs during the 2018 LTRA assessment period. However, additional transmission projects will be required to integrate large amounts of onshore and offshore wind generation or to expand access to wind or hydropower from neighboring systems.

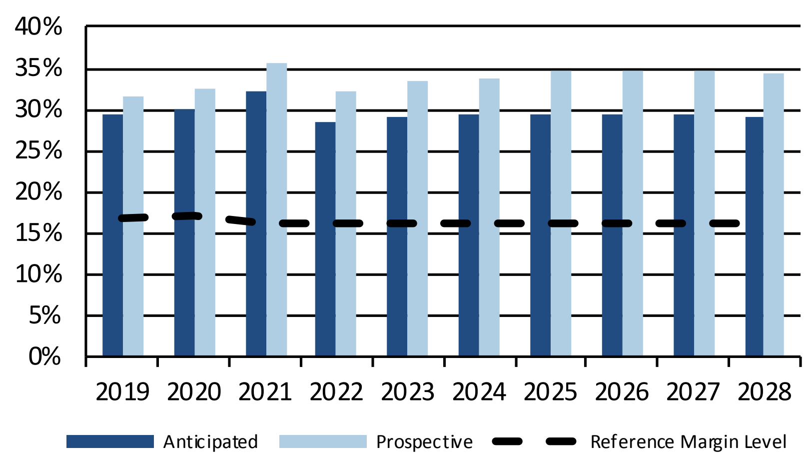
Demand, Resources, and Reserve Margins (MW)

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	25,511	25,298	25,136	25,021	24,942	24,889	24,864	24,874	24,912	24,950
Demand Response	464	420	624	624	624	624	624	624	624	624
Net Internal Demand	25,047	24,878	24,511	24,396	24,317	24,264	24,239	24,249	24,288	24,326
Additions: Tier 1	1,101	1,204	1,689	1,752	1,752	1,752	1,752	1,752	1,752	1,752
Additions: Tier 2	70	166	353	424	584	611	787	787	787	787
Net Firm Capacity Transfers	1,481	1,265	1,247	81	81	81	81	81	81	81
Existing-Certain and Net Firm Transfers	31,317	31,116	30,735	29,586	29,612	29,636	29,654	29,666	29,676	29,686
Anticipated Reserve Margin (%)	29.43	29.92	32.28	28.46	28.98	29.36	29.57	29.56	29.40	29.24
Prospective Reserve Margin (%)	31.60	32.49	35.65	32.13	33.33	33.84	34.77	34.77	34.60	34.42
Reference Margin Level (%)	16.91	17.20	16.36	16.36	16.36	16.36	16.36	16.36	16.36	16.36

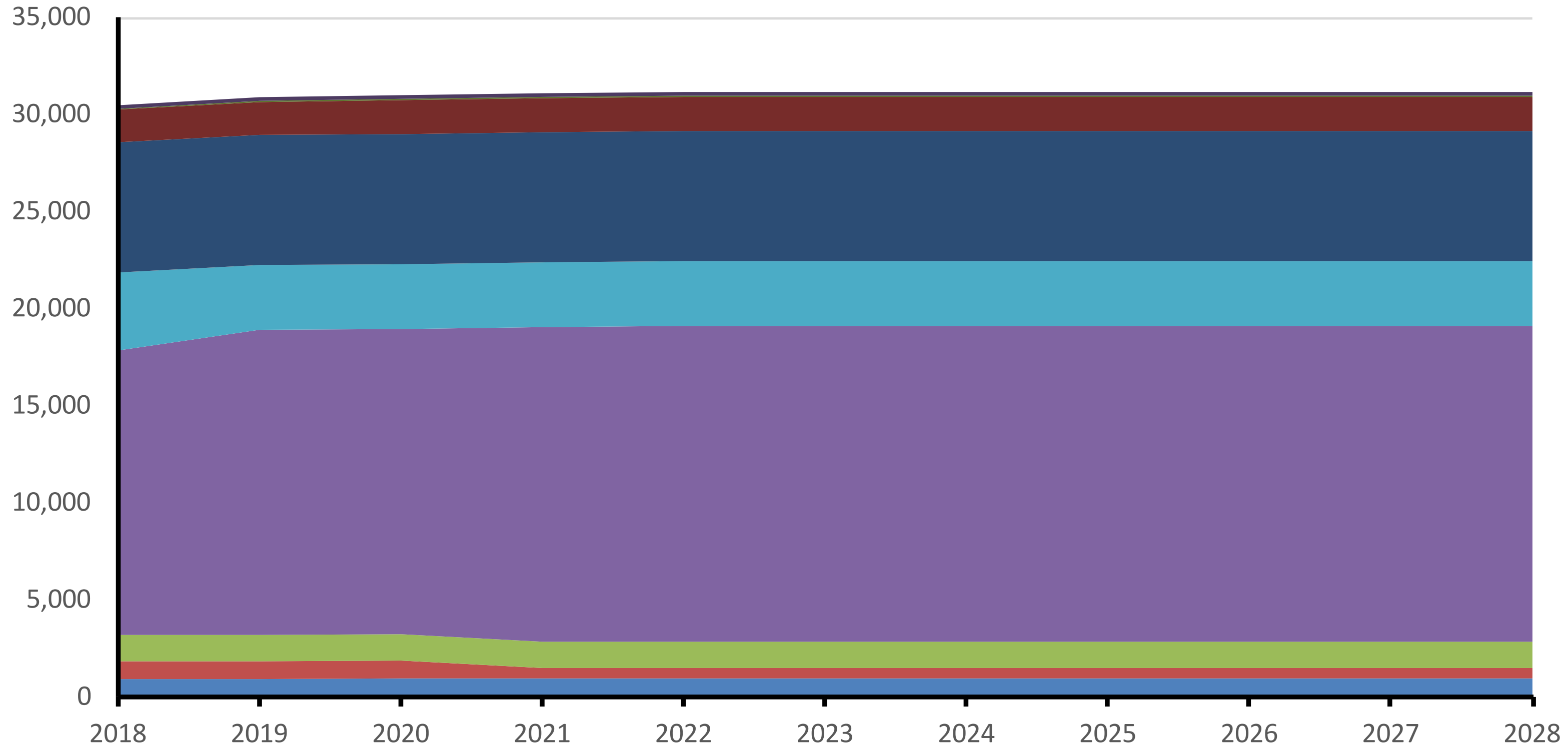
2019 On-Peak Fuel-Mix



Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	953	3%	990	3%
Coal	917	3%	533	2%
Hydro	1,357	4%	1,355	4%
Natural Gas	15,712	51%	16,261	52%
Nuclear	3,335	11%	3,335	11%
Other	1	0%	1	0%
Petroleum	6,699	22%	6,699	21%
Pumped Storage	1,686	5%	1,752	6%
Solar	66	0%	66	0%
Wind	189	1%	189	1%
Total	30,916	100%	31,182	100%



Planning Reserve Margins



NPCC-New England Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	953	990	990	990	990	990	990	990	990	990
Coal	917	917	533	533	533	533	533	533	533	533
Hydro	1,357	1,357	1,355	1,355	1,355	1,355	1,355	1,355	1,355	1,355
Natural Gas	15,712	15,712	16,197	16,261	16,261	16,261	16,261	16,261	16,261	16,261
Nuclear	3,335	3,335	3,335	3,335	3,335	3,335	3,335	3,335	3,335	3,335
Other	1	1	1	1	1	1	1	1	1	1
Petroleum	6,699	6,699	6,699	6,699	6,699	6,699	6,699	6,699	6,699	6,699
Pumped Storage	1,686	1,752	1,752	1,752	1,752	1,752	1,752	1,752	1,752	1,752
Solar	66	66	66	66	66	66	66	66	66	66
Wind	189	189	189	189	189	189	189	189	189	189
Total	30,916	31,019	31,118	31,182	31,182	31,182	31,182	31,182	31,182	31,182

Probabilistic Assessment Overview

- **General Overview:** The New England area is a summer-peaking area. For 2020, the LOLH is 0.027 hours/year and the EUE is 12.5 MWh; in 2022 those values are 0.007 hours/year and 2.713 MWh, respectively. The forecast 50/50 peak demand for 2022 is lower than 2020 with lower forecast capacity resources. The summer months provide the greatest contribution to these annual metrics.
- **Modeling:** Assumptions used in this ProbA are consistent with those used in *NPCC 2018 Long Range Adequacy Overview.*[1] The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over inter-connections with neighboring Planning Coordinator areas, transmission transfer capabilities, capacity, and/or load relief from available operating procedures as prescribed by the NPCC resource adequacy criterion:[2]
    - New England develops an independent demand forecast for its area using historical hourly demand data from individual member utilities that is based upon revenue quality metering. This data is then used to develop historical demand data on which the regional peak demand and energy forecasts are subsequently based. From this, ISO New England develops a forecast of both state and system seasonal peak and energy demands. The peak demand fore-cast for the Region and the states can be considered a coincident peak demand forecast. This demand forecast is referred to as the gross demand forecast (without reductions).
    - The seasonal claimed capability as established through the claimed capability audit is used to represent the non-intermittent thermal resources in New England. The seasonal claimed capability for intermittent thermal resources is based on their historical median net real power output during reliability hours (2:00–6:00 p.m.).
    - New England uses the seasonal claimed capability as established through the claimed capability audit to represent the hydro resources. The seasonal claimed capability for intermittent hydro resources is based on their historical median net real power output during reliability hours (2:00–6:00 p.m.).
    - The majority of solar resource development in New England consists of the state-sponsored distributed behind-the-meter PV resources that do not partici-pate in wholesale markets but reduce the system load observed by ISO-New England. These resources are modeled as a load modifier on an hourly basis based on the 2002 historical hourly weather profile.
    - New England models wind resources using the seasonal claimed capability that is based on their historical median net real power output during reliability hours (2:00–6:00 p.m.).

[1] https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

[2] https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

- **Probabilistic vs. Deterministic:** Details regarding the differences between the probabilistic and deterministic representations can be found in the *NERC 2018 Probabilistic Assessment – NPCC Region.*[3] Additional assumptions include the following:
  - The loads for each area were modeled on an hourly, chronological basis. This is based on the 2002 load shape for the summer period and the 2003/04 load shape for the winter period.[4]
  - In addition to the annual update to New England's peak demand and energy forecast, ISO New England also forecasts the anticipated growth and impact of behind-the-meter PV resources within the area that do not participate in wholesale markets. ISO-New England's forecast for these resources is developed with stakeholder input.
  - New England also develops a forecast of long-term savings in peak and energy use for the area and for each state stemming from state-sponsored energy-efficiency programs. These programs include the use of more efficient lighting, motors, refrigeration, HVAC equipment, control systems, and industrial process equipment. ISO New England's forecast of energy-efficiency resources is developed with stakeholder input.
  - The New England area modeled operating procedures that included reduced operating reserves and voltage reduction before firm load has to be disconnected.
  - Starting on June 1, 2018, price-responsive demand response was fully integrated into New England's energy and reserve markets. These resources are treated similarly to generating resources. They are dispatchable and participate in both the daily energy and reserves markets.
  - Transmission additions and retirements were assumed consistent with this NERC *2018 Long-Term Reliability Assessment*.
  - In the NPCC ProbA simulations, all areas within NPCC received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously in all areas and subareas.

[3] Available December 2018 at the following: https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

[4] https://www.npcc.org/Library/Other/Forms/Public%20List.aspx

Base Case Study

- **Results Trending:** The previous study, *NERC Probabilistic Assessment – NPCC Region,* estimated an annual LOLH = 0.189 hours/year and a corresponding EUE equal to 140.9 MWh for the year 2020.* The net forecast 50/50 peak demand for 2020 was lower than reported in the previous study with higher estimated forecast planning and forecast operable reserve margins. As a result, both the LOLH and the EUE have improved for 2020.

Summary of Results			
Reserve Margin			
	2020*	**2020**	**2022**
Anticipated	18.2	29.9	28.5
Reference	15.9	17.2	16.4
ProbA Forecast Operable	9.4	20.7	19.0
Annual Probabilistic Indices			
	2020*	**2020**	**2022**
EUE (MWh)	140.9	12.53	2.71
EUE (ppm)	1.00	0.10	0.02
LOLH (hours/year)	0.19	0.03	0.01

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: ISO-NE's Reference Margin Level is based on the capacity needed to meet the NPCC one-day-in-10 years LOLE resource planning reliability criterion. The capacity needed, referred to as the ICR, varies from year-to-year, depending on projected system conditions (demand, generation, transmission, imports, etc.). The ICR is calculated on an annual basis, four years in advance for each forward capacity market auction and results in a Reference Margin Level of 16.9 percent in 2019, 17.2 percent in 2020, and 16.4 percent in 2021 as expressed in terms of the 50/50 peak demand forecast that was published in May 2018. In this assessment, the last calculated Reference Margin Level (16.4 percent) is applied for the remaining seven years of the LTRA forecast. ISO-NE's Anticipated Reserve Margin is expected to stay above the Reference Margin Level during the assessment period.

Demand: ISO-NE develops an independent demand forecast for its BA area using historical hourly demand data from individual member utilities. This data is used to develop the regional hourly peak demand and energy forecasts. ISO-NE then develops a forecast of both state and system hourly peak and energy demands. The regional peak and states demand forecast is considered coincident. This demand forecast is the gross demand forecast. Annually, ISO-NE also forecasts the load reduction impact of behind-the-meter PV resources and the reductions to peak demand and energy due to passive DR programs, which are comprised mostly of EE. EE in 2019 is 3,066 MW and is forecast to grow to 3,757 MW by 2021 and increase to over 5,229 MW by 2028. Nameplate BTM PV in 2019 is 2,039 MW and is forecast to grow to 2,571 MW by 2021 and increase to 3,867 MW by 2028. The BTM PV and EE forecasts are seen as reductions (net demand forecast) to the gross demand forecast.

ISO-NE is a summer-peaking electrical power system. The reference demand forecast is based on the reference economic forecast, which reflects the regional economic conditions that are expected to occur. Both the summer peak total internal demand (TID) and the net energy for load are forecast to decrease from 2019 to 2028; the TID decreases from 25,511 MW in 2019 to 24,950 MW in 2028. This amounts to a nine-year summer TID CAGR of -0.25 percent. The NEL is expected to decrease from 122,498 GWh in 2019 to 114,766 GWh in 2028, which amounts to an energy CAGR of -0.72 percent.

Demand-Side Management: On June 1, 2018, ISO-NE integrated price-responsive DR into the energy and reserve markets. Approximately 408 MW of DR participate in these markets and are dispatchable (i.e., treated similar to generators). Because of these changes, DR are no longer be considered "emergency resources," which were previously dispatched during actual of forecast capacity deficiencies under system operator EOPs. Within ISO-NE's ICR calculations, DR availability is based on historical DR performance from the past five years. The summer performance of DR was 94 percent, and the winter performance was 95 percent.

Distributed Energy Resources: New England has 188 MW (1,371 MW nameplate) of wind generation and 633 MW (1,727 MW nameplate) of BTM PV. Approximately 8,000 MW (nameplate) of wind generation projects have requested generation interconnection studies. BTM PV is forecast to grow to 1,070 MW (3,867 MW nameplate) by 2028. The BTM PV peak load reduction values are calculated as percentage of ac nameplate. The percentages, which include the effect of diminishing PV production at time of the system peak as increasing PV penetrations shift the timing of peaks later in the day, decrease from 36.6 percent of nameplate in 2018 to about 27 percent in 2028.

Generation: Generating capacity that has been added since the *2017 LTRA* consists primarily of 1,522 MW nameplate of combined-cycle units and 120 MW nameplate of natural gas turbines. Existing certain capacity for 2018 is 30,473 MW. A total of ~1,101 MW of Tier 1 natural-gas-fired capacity is projected to be added by 2019. Tier 2 capacity additions scheduled for 2019 include 70 MW of natural-gas-fired, solar, and wind generation. In 2020, scheduled Tier 2 capacity additions total 166 MW of the same types of technologies.

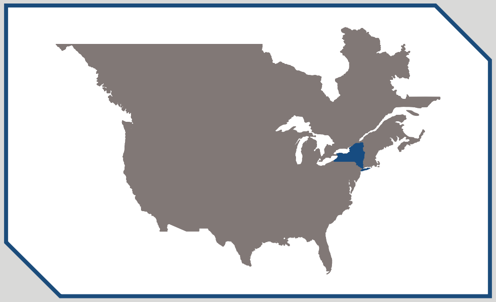
The combination of constrained natural gas pipelines during winter, indeterminate LNG and fuel oil deliveries, and upcoming planned retirements of nuclear and non-natural-gas-fired generation has prompted ISO-NE to undertake an operational fuel security analyses. This new reliability analysis, which focuses on winter operations, has pre-defined electric and natural gas sector topology along with fuel supply assumptions that are used to gauge the impact that certain prolonged, regional fuel infrastructure outages have upon BPS reliability. To address reliability issues relating to fuel/energy security, FERC directed ISO New England (ISO-NE) to file tariff revisions by August 31, 2018, to address fuel security concerns in the near term and by July 1, 2019, to address fuel security concerns over the long term.

Capacity Transfers: New England is interconnected with the three BAs of Quebec, the Maritimes, and New York. ISO-NE takes into account this transfer capability to assure that their limits do not impact regional resource adequacy. ISO-NE's forward capacity market methodology limits the purchase of import capacity based on the interconnection transfer limits.

ISO-NE's capacity imports are assumed to range from 1,600 MW to 1,250 MW during the 2018 to 2021 period and to decrease to 81 MW for the remainder of the LTRA years since the forward capacity market has only secured resources through the 2021 period.

Transmission: There are a number of new projects planned and under construction that are needed to maintain transmission reliability. The most significant area of concern is Boston. The greater Boston transmission project has addressed many of these concerns and most of the project is expected to be in service by December 2019 with the last component possibly delayed until June 2021. The second area that remains a significant concern is the SEMA/RI area. This area has both import constraints and significant constraints on moving power within the area. Similar to the Boston area, system operators will be reliant on the out-of-merit dispatch of local resources and system reconfigurations to meet system needs. Solutions to address time sensitive needs in SEMA/RI have been developed.

Transmission reliability needs in the Greater Hartford-Central Connecticut area are being addressed with projects that are under construction or already in service. Projects to address reliability needs in Southwest Connecticut, which are closely linked to the GHCC project, are also under construction or already in service. The Maine Power Reliability Program added significant 345 kV infrastructure that has already been completed and other parts of the project are now under construction and are expected to be in service by November 2018. In the past, New Hampshire and Vermont had been studied together. Reliability upgrades needed in Vermont are under construction. The New Hampshire portion upgrades are predominantly 115 kV based within the seacoast area with an anticipated in-service date of December 2019. In Western Massachusetts, a suite of reliability based projects is almost complete in the Pittsfield/Greenfield area.



NPCC-New York

The New York Independent System Operator (NYISO) is the only Balancing Authority within the state of New York. NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. NYISO manages the New York State transmission grid that encompasses approximately 11,000 miles of transmission lines and over 47,000 square miles and serves the electric needs of 19.5 million people. New York experienced its all-time peak load of 33,956 MW in the summer of 2013.

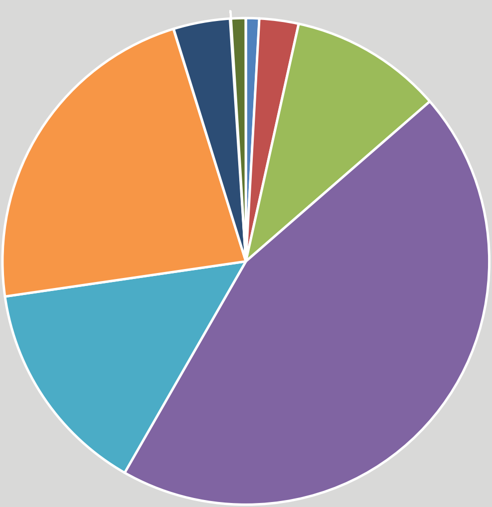
Highlights

- The 2018 final RNA has identified no reliability needs. The base case assumptions include the retirement of over 3,600 MW, including the Indian Point Energy Center (IPEC) and the addition of over 2,300 MW of new supply resources. Additionally, the NYISO completed a generator deactivation assessment in 2017 for IPEC, which concluded there are no generation deactivation reliability needs.
- The ten-year annual average energy and demand growth rates are slightly declining. The baseline forecast includes upward adjustments for usage of electric vehicles and downward adjustments for the impacts of energy efficiency trends, distributed energy resources, and behind-the-meter solar PV.
- The Western New Your public policy project proposed by NextEra (Empire State Line) has been selected by the NYISO's board of directors and is included in the NYISO planning models. Also, the NYISO is currently evaluating the transmission proposals for the ac transmission public policy transmission need to identify the more efficient or cost-effective solutions to add more transfer capability between upstate and downstate New York.
- Demand and consumption in New York are heavily influenced by state energy efficiency and renewable energy public policy programs, such as the clean energy standard that aims to produce 50 percent of state-wide energy consumption from renewables by 2030.

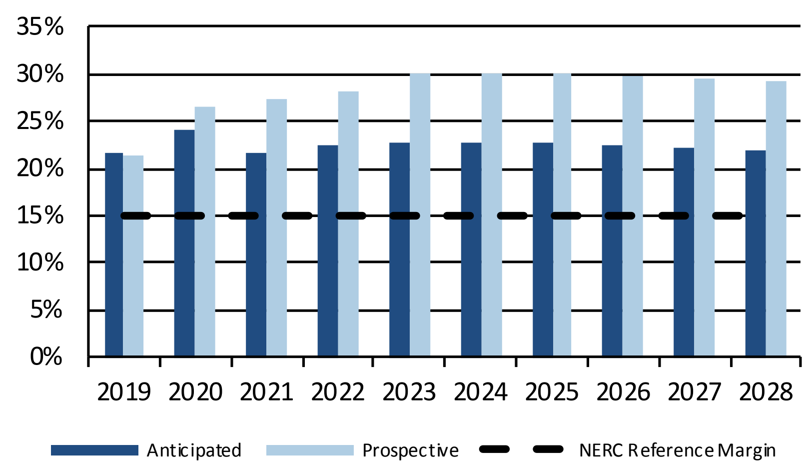
Demand, Resources, and Reserve Margins (MW)

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	32,857	32,629	32,451	32,339	32,284	32,276	32,299	32,343	32,403	32,469
Demand Response	871	871	871	871	871	871	871	871	871	871
Net Internal Demand	31,987	31,759	31,581	31,469	31,414	31,406	31,429	31,473	31,533	31,599
Additions: Tier 1	933	1,978	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
Additions: Tier 2	67	835	1,881	1,881	2,389	2,389	2,389	2,389	2,389	2,389
Net Firm Capacity Transfers	1,279	1,785	1,800	1,942	1,942	1,942	1,942	1,942	1,942	1,942
Existing-Certain and Net Firm Transfers	37,954	37,442	36,419	36,561	36,561	36,561	36,561	36,561	36,561	36,561
Anticipated Reserve Margin (%)	21.57	24.12	21.64	22.53	22.74	22.77	22.68	22.51	22.28	22.02
Prospective Reserve Margin (%)	21.50	26.47	27.31	28.22	30.06	30.09	30.00	29.82	29.57	29.30
Reference Margin Level (%)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

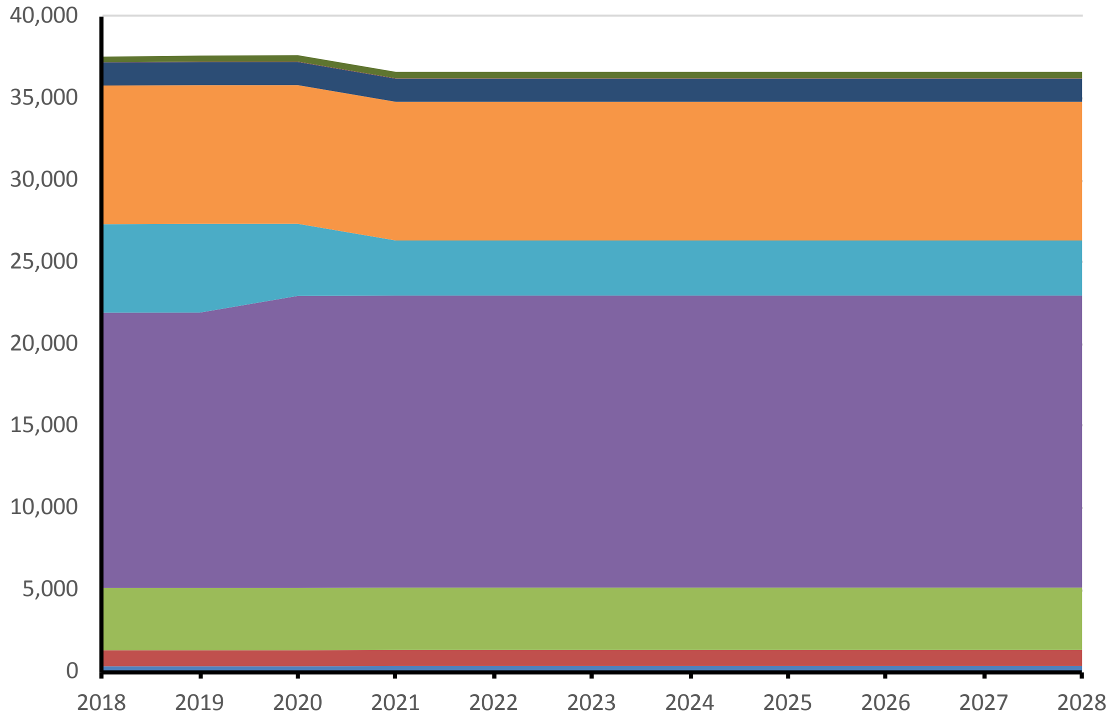
2019 On-Peak Fuel-Mix



Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	331	1%	350	1%
Coal	979	3%	979	3%
Hydro	3,803	10%	3,803	10%
Natural Gas	16,806	45%	17,826	49%
Nuclear	5,420	14%	3,364	9%
Petroleum	8,465	23%	8,465	23%
Pumped Storage	1,409	4%	1,409	4%
Solar	27	0%	27	0%
Wind	369	1%	394	1%
Total	37,609	100%	36,616	100%



Planning Reserve Margins



NPCC-New York Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	331	331	350	350	350	350	350	350	350	350
Coal	979	979	979	979	979	979	979	979	979	979
Hydro	3,803	3,803	3,803	3,803	3,803	3,803	3,803	3,803	3,803	3,803
Natural Gas	16,806	17,826	17,826	17,826	17,826	17,826	17,826	17,826	17,826	17,826
Nuclear	5,420	4,401	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364
Petroleum	8,465	8,465	8,465	8,465	8,465	8,465	8,465	8,465	8,465	8,465
Pumped Storage	1,409	1,409	1,409	1,409	1,409	1,409	1,409	1,409	1,409	1,409
Solar	27	27	27	27	27	27	27	27	27	27
Wind	369	394	394	394	394	394	394	394	394	394
Total	37,609	37,635	36,616	36,616	36,616	36,616	36,616	36,616	36,616	36,616

Probabilistic Assessment Overview

- **General Overview:** The New York area is summer-peaking. The LOLH for 2020 and 2022 are 0.001 and 0.000 (hours/year), respectively, with corresponding EUE values of 0.073 and 0.032 (MWh), which trend lower than the past ProbA results. The decreasing trend is mainly due to the decrease in the Forecast 50/50 peak demand.[1]
- **Modeling:** Assumptions used in this ProbA are consistent with those used in *NPCC 2018 Long Range Adequacy Overview.*[2] The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion:[3]
  - New York employs a multi-stage process in developing load forecasts for each of the eleven zones within the New York area. In the first stage, baseline energy and peak models are built based on projections of end-use intensities and economic variables. In the second stage, the incremental impacts of behind-the-meter solar PV and distributed generation are deducted from the forecast, and the incremental impacts of electric vehicle usage are added to the forecast. In the final stage, the New York ISO aggregates load forecasts by load zone.
  - Installed capacity values for thermal units are based on the minimum of seasonal dependable maximum net capability test results and the capacity resource interconnection service MW value. Generator availability is derived from the most recent calendar five-year period forced outage data. Units are modeled using a multi-state representation that represents an equivalent forced outage rate on demand. Planned and scheduled maintenance outages are modeled based upon schedules received by the New York ISO and adjusted for historical maintenance.
  - Large New York hydro units are modeled as thermal units with a corresponding multi-state representation that represents an equivalent forced outage rate on demand. For run-of-river units, New York provides 8,760 hours of historical unit profiles for each year of the most recent five-year calendar period for each facility based on production data. Run-of-river unit seasonality is captured by applying an annual shape for all run-of-river units in each draw.
  - New York provides 8,760 hours of historical solar profiles for each year of the most recent five-year calendar period for each solar plant based on production data. Solar seasonality is captured by applying an annual solar shape for all solar units in each draw.
  - New York provides 8,760 hours of historical wind profiles for each year of the most recent five-year calendar period for each wind plant based on production data. Wind seasonality is captured by randomly selecting an annual wind shape for each wind unit in each draw. Each wind shape is equally weighted.
- **Probabilistic vs. Deterministic:** Details regarding the differences between the probabilistic and deterministic representations can be found in the *NERC 2018 Probabilistic Assessment – NPCC Region*:[4]
  - The loads for each area were modeled on an hourly, chronological basis; this is based on the 2002 load shape for the summer period and the 2003/04 load shape for the winter period.[5]
  - The New York area modeled operating procedures that included reduced operating reserves, voltage reduction, and implementation of DR programs before firm load has to be disconnected.

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[1] For the NPCC-New York assessment area, NYISO uses a probabilistic model with installed capacity and equivalent forced outage rates for all resources in order to identify resource requirements. The result of NYISO's analysis produces the installed reserve margin (IRM), which is established by the New York State Reliability Council (NYSRC) for one "capability year" (May 1, 2018 through April 30, 2019). The NERC 15 percent Reference Margin Level was used for the entire 10-year assessment period.

[2] https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

[3] https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

[4] Available December 2018 at the follow: https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

[5] https://www.npcc.org/Library/Other/Forms/Public20List.aspx

- New York's Special Case Resources Program and Emergency DR Program are modeled as an operating procedure step activated to minimize the probability of customer load disconnection; the programs are only activated in zones from which they are capable of being delivered.
- Transmission additions and retirements modeled were consistent with the *NERC 2018 Long-Term Reliability Assessment.*
- In the NPCC ProbA simulations, all areas modeled received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously in all areas and subareas.

Base Case Study

- **Results Trending:** The previous study, *NERC Probabilistic Assessment – NPCC-NY Region*, estimated an annual LOLH = 0.004 hours/year and a corresponding EUE equal to 2.059 MWh for the year 2020.* The net forecast 50/50 peak demand for 2020 was lower than reported in the previous study with lower estimated forecast capacity resources. As a result, the LOLH has slightly increased.

Summary of Results			
Reserve Margin			
	2020*	**2020**	**2022**
Anticipated	26.27	24.1	22.5
Reference	15.0	15.0	15.0
ProbA Forecast Operable	18.8	15.3	13.7
Annual Probabilistic Indices			
	2020*	**2020**	**2022**
EUE (MWh)	2.06	0.07	0.03
EUE (ppm)	0.01	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: The NYISO provides significant support to the New York State Reliability Council, which conducts an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the NPCC and the New York State Reliability Council resource adequacy criterion of a LOLE of no greater than 0.1 days per year. The IRM for the 2018/2019 capability year (May 1 through April 30) is 18.2 percent of the forecasted NYCA peak load (all values in the IRM calculation are based upon full installed capacity values of resources). The IRM has varied historically from 15 percent to 18.2 percent. The NYISO is forecasting adequate installed capacity to meet the 0.1 days/year LOLE for all 10 years of the reliability needs assessment (2019–2028).

Demand: The peak load forecast is based upon a model that incorporates forecasts of economic drivers, end use and technology trends, and normal weather conditions. The NYISO incorporates the impacts of energy efficiency and technology trends directly into the forecast model with additional adjustments for DERs, electric vehicles and behind-the-meter solar PV. The baseline forecast includes upward adjustments for increased usage of electric vehicles and downward adjustments for the impacts of energy efficiency trends, DERs, and behind-the-meter solar PV. The 10-year annual average energy growth rate is about the same as last year (-.14 percent per year in 2018 versus -.23 percent in 2017). The 10-year annual average summer-peak demand growth rate is lower than last year (-.13 percent per year in 2018 versus 0.07 percent in 2017).

Demand-Side Management: The NYISO's planning process accounts for DR resources that participate in the NYISO's reliability-based DR programs based on the enrolled MW derated by historical performance.

Distributed Energy Resources: The NYISO published a report in February 2017 that provided a roadmap that will be used over the next three to five years as a framework to develop the market design elements, functional requirements, and tariff language necessary to implement the NYISO's vision to integrate DER into NYISO's energy, ancillary services, and capacity markets. The NYISO also published a market design concept paper in December 2017 and is currently in the process of developing the market design of this initiative. Behind-the-meter solar PV are currently being addressed operationally in the day-ahead and real-time load forecasts. A solar forecasting system to integrate with the day-ahead and real-time markets was implemented in 2017.

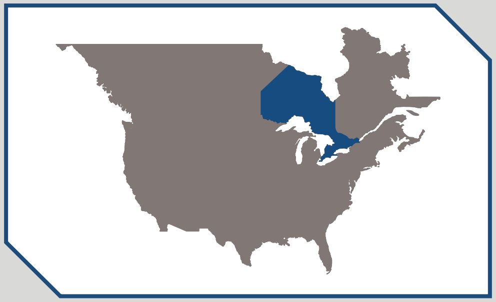
Generation: Entergy has announced its intent to deactivate the Indian Point Energy Center Unit No. 2 and 3 (approximately 2,150 MW total in 2020 and 2021, respectively). The NYISO completed a generator deactivation assessment in 2017 regarding the deactivation of the Indian Point Energy Center Unit No. 2 and 3, which concluded that no generation deactivation reliability needs arise. The NYISO's 2018 reliability planning process includes approximately 2,300 MW of proposed generation, including the 680 MW CPV Valley Energy Center (which entered into service in 2018) and the 1,020 MW Cricket Valley Energy Center (which is expected to enter into service in 2020).

Capacity Transfers: The models used for the NYISO planning studies include the firm capacity transactions (purchases and sales) with the neighboring systems as a base case assumption. The net MW seasonal values are also published in the NYISO's Gold Book[62] and include the yearly election of the unforced capacity deliverability rights and other firm capacity transactions made via the applicable processes.

Transmission: The *2018 Reliability Needs Assessment*[63] identified no reliability needs. The base case assumptions include the retirement of over 3,600 MW, including the Indian Point Energy Center and the addition of over 2,300 MW of resources. The 2018 reliability planning process also includes proposed transmission projects (including the NextEra's Empire State Line project selected under the Western New York public policy transmission planning process) and transmission owner LTPs that have met the RPP inclusion rules.

[62] 2018 NYISO Gold Book https://home.nyiso.com/wp-content/uploads/2018/04/2018-Load-Capacity-Data-Report-Gold-Book.pdf

[63] NYISO 2018 Reliability Needs Assessment: https://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2018-07-19/2018RNA_Report.pdf



NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority for the province of Ontario. The province of Ontario covers more than one million square kilometers (415,000 square miles) and has a population of more than 13 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

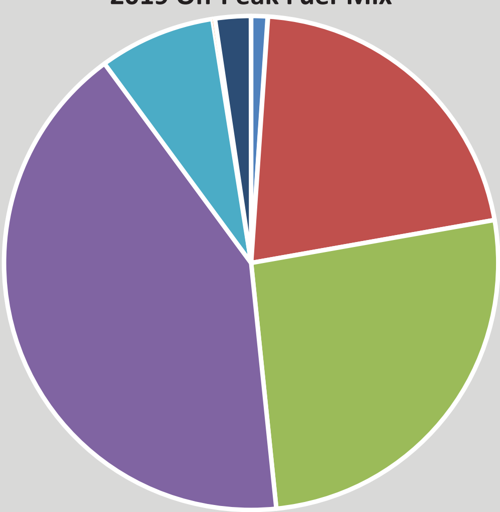
Highlights

- Projected margin shortfalls in the later part of the LTRA horizon are a reflection of substantial resource turnovers driven primarily by nuclear retirements and refurbishments.
- The IESO is actively developing a suite of market renewal initiatives; in particular, an incremental capacity auction will be the primary vehicle to address capacity needs.
- Integration of distributed energy resources and changing demand and supply patterns are creating, and will continue to create, new operating challenges in managing the BPS while also providing greater customer choice and opportunity to optimize grid reliability services. The IESO collaborates with local distribution companies to ensure it has visibility of their operations is able to forecast their output over different time frames, study their impact on reliability, and coordinate their operations to ensure reliability.

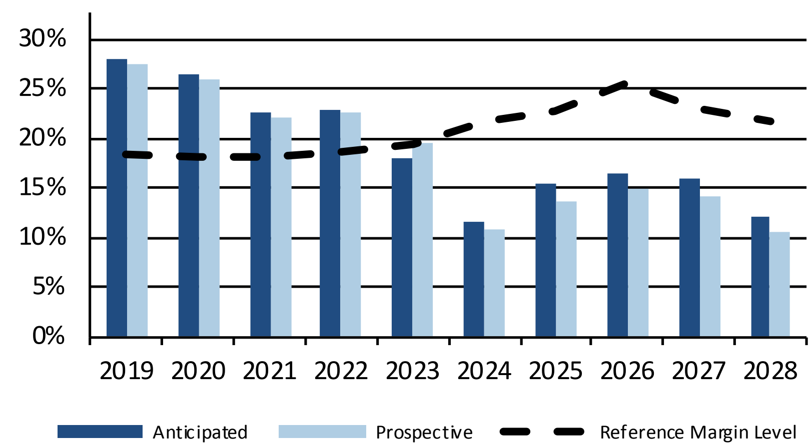
Demand, Resources, and Reserve Margins

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	22,016	22,085	22,155	22,098	22,139	22,251	22,302	22,146	22,263	22,263
Demand Response	533	549	549	549	549	549	549	549	549	549
Net Internal Demand	21,483	21,536	21,606	21,548	21,589	21,701	21,753	21,596	21,713	21,714
Additions: Tier 1	970	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	26,664	26,356	25,628	25,628	24,598	23,352	24,230	24,294	24,294	23,484
Anticipated Reserve Margin (%)	28.63	27.08	23.30	23.63	18.62	12.27	16.04	17.18	16.54	12.81
Prospective Reserve Margin (%)	28.24	25.97	22.20	22.52	19.53	10.87	13.70	14.81	14.19	10.46
Reference Margin Level (%)	18.37	18.05	18.02	18.51	19.43	21.59	22.69	25.43	22.92	21.60

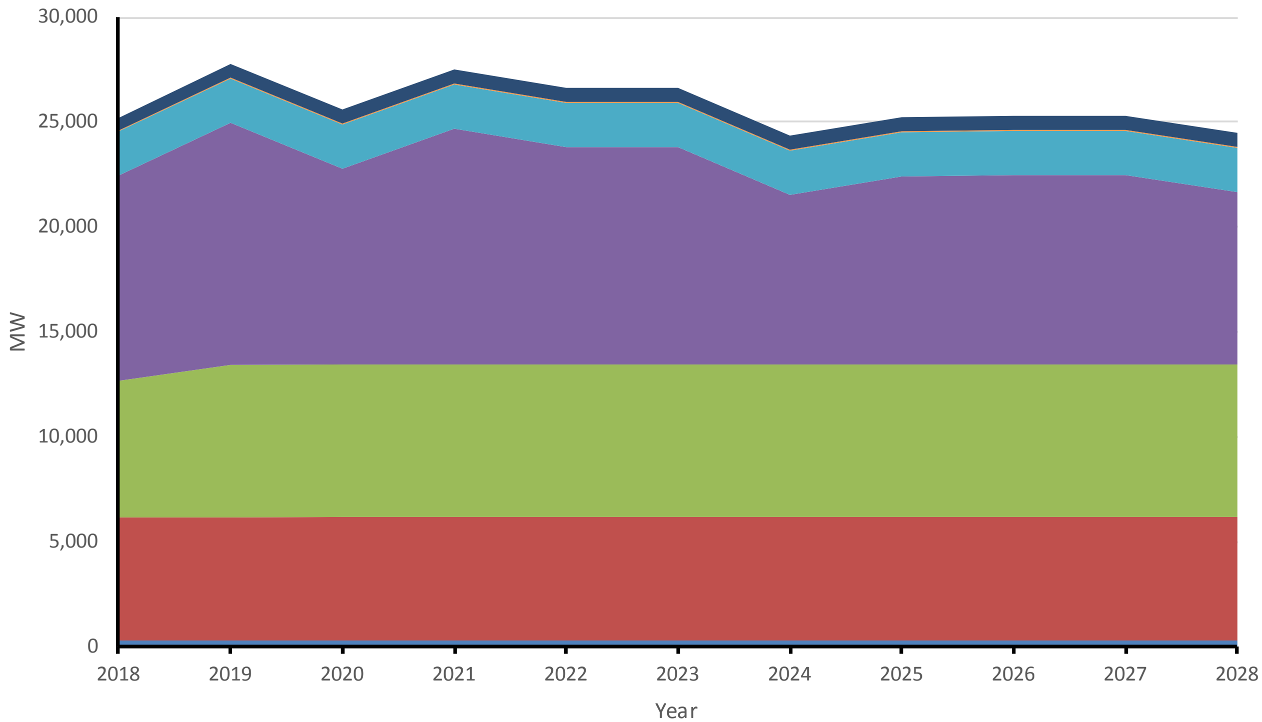
2019 On-Peak Fuel-Mix



Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	300	1%	300	1%
Hydro	5,868	21%	5,888	24%
Natural Gas	7,267	26%	7,267	30%
Nuclear	11,537	42%	8,213	34%
Petroleum	2,107	8%	2,107	9%
Solar	47	0%	47	0%
Wind	650	2%	671	3%
Total	27,775	100%	24,492	100%



Planning Reserve Margins



NPCC-Ontario Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	300	300	300	300	300	300	300	300	300	300
Hydro	5,868	5,888	5,888	5,888	5,888	5,888	5,888	5,888	5,888	5,888
Natural Gas	7,267	7,267	7,267	7,267	7,267	7,267	7,267	7,267	7,267	7,267
Nuclear	11,537	9,327	11,235	10,357	10,357	8,081	8,959	9,023	9,023	8,213
Petroleum	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107
Solar	47	47	47	47	47	47	47	47	47	47
Wind	650	671	671	671	671	671	671	671	671	671
Total	27,775	25,606	27,514	26,636	26,636	24,360	25,238	25,302	25,302	24,492

Probabilistic Assessment Overview

- **General Overview:** The Ontario area is a summer-peaking area. No significant LOLH was observed. The estimated EUE is negligible. The Anticipated Reserve Margins are well above 18 percent and 19 percent levels in 2020 and 2022, respectively. Any contribution to the LOLH and EUE occur during the peak (summer) monthly period.
- **Modeling:** Assumptions used in this ProbA are consistent with those used in *NPCC 2018 Long Range Adequacy Overview.*[1] The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion:[2]
    - The Ontario demand forecast includes the impact of conservation, time-of-use rates, and other price impacts as well as the effects of embedded (distribution connected) generation. However, the demand forecast does not include the impacts of "controllable" DR programs, such as dispatchable loads and DR; the capacity from these programs is treated as resource.
    - Ontario capacity values and planned outage schedules for thermal units are based on monthly maximum continuous ratings and planned outage information contained in market participant submissions. The available capacity states and state transition rates for each existing thermal unit are derived based on analysis of a rolling five-year history of actual forced outage data.
    - Hydroelectric resources are modelled in Ontario as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity, and monthly energy values are determined on an aggregated basis for each zone based on historical data.
    - Solar generation in Ontario is aggregated on a zonal basis and is modelled as load modifiers. The contribution of solar resources is modelled as fixed hourly profiles that vary by month and season.
    - Capacity limitations due to variability of wind generators in Ontario are captured by providing probability density functions from which stochastic selections are made. Wind generation is aggregated on a zonal basis and modelled as an energy limited resource with a cumulative probability density function (CPDF) that represents the likelihood of zonal wind contribution being at or below various capacity levels during peak demand hours. The cumulative probability density functions vary by month and season.

[1] https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

[2] https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

- **Probabilistic vs. Deterministic:** Details regarding the differences between the probabilistic and deterministic representations can be found in the *NERC 2018 Probabilistic Assessment – NPCC Region*:[3]
  - The loads for each area were modeled on an hourly, chronological basis; this is based on the 2002 load shape for the summer period and the 2003/04 load shape for the winter period.[4]
  - The Ontario area modeled operating procedures that included reduced operating reserves, voltage reduction, and implementation of DR programs before firm load has to be disconnected.
  - The loads for each area were modeled on an hourly, chronological basis; this is based on the 2002 load shape for the summer period and the 2003/04 load shape for the winter period.
  - The Ontario area modeled operating procedures that included reduced operating reserves, voltage reduction, and public appeals before firm load has to be disconnected.
  - In Ontario, DR is treated as a resource instead of a load modifier.
  - Ontario transmission additions and retirements assumed were consistent with this *NERC 2018 Long-Term Reliability Assessment*.
  - In the NPCC ProbA simulations, all areas received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously in all areas and subareas.

Base Case Study

- **Results Trending:** The previous study *NERC Probabilistic Assessment – NPCC Region* estimated an annual LOLH = 0.000 hours/year and a corresponding EUE equal to 0.0 (ppm) for the year 2020.* The 2020 Forecast 50/50 peak demand forecast is relatively flat compared to the previous assessment; forecast capacity resources increased as compared to the previous assessment. No material difference in estimated LOLH and EUE is observed between the two assessments.

Summary of Results			
Reserve Margin			
	2020*	**2020**	**2022**
Anticipated	26.3	27.1	23.6
Reference	17.7	18.0	18.5
ProbA Forecast Operable	11.9	10.5	11.5
Annual Probabilistic Indices			
	2020*	**2020**	**2022**
EUE (MWh)	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000

*Represents 2016 ProbA results for 2020.

3 Available December 2018 at the following: https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

4 https://www.npcc.org/Library/Other/Forms/Public20List.aspx

Planning Reserve Margins: The Anticipated Reserve Margins fall below the Reference Margin level in the mid-2020s driven by nuclear retirements, the nuclear refurbishment program, and the assumption that certain generation resources are not available once their generation contracts have expired. The development of a capacity market in Ontario, to re-acquire off-contract resources or obtain new resources, will be the primary vehicle to address capacity needs. Other options include coordinating outages outside the peak load seasons or periods of potential capacity shortages, the potential for more conservation and demand response, and the reliance of non-firm imports.

Demand: Growth in demand is slight and driven by population growth, economic expansion, and increased penetration of electric devices. Offsetting that growth are reductions from conservation and increased output from embedded generation.

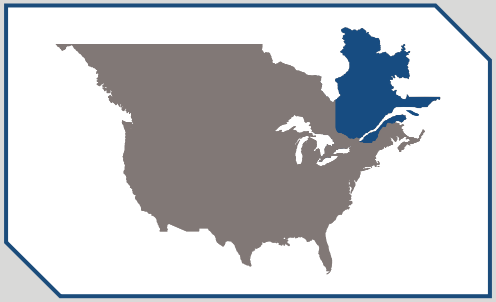
Demand-Side Management: Ontario has two main DR programs: Dispatchable loads and the capacity procured through an annual demand response auction. The IESO's Demand Response Working Group continues to work with DR providers to evolve DR in the IESO-administered markets, including improving the utilization of DR in real time operations.

Distributed Energy Resources: The IESO estimates total DERs in Ontario exceed 4,000 MW, including over 3,000 MW of distribution connected generation capacity on contract with the IESO. In response, The IESO recently concluded two initiatives to better accommodate DERs; the IESO is now able to schedule additional 30-minute operating reserve to assist in addressing flexibility needs, and the IESO procured 55 MW of regulation to expand its capability to schedule more regulation as required. The IESO continues to collaborate with the DER community to enhance the reliability and efficiency of Ontario's electricity grid.

Generation: Retirement of the Pickering Nuclear Generating Station (total capacity of approximately 3,000 MW) is expected by 2025. Nuclear refurbishments at Bruce and Darlington generating stations will reduce the generation capacity available over peak seasons. Over the next 10 years, Ontario expects to add about 1,710 MW of new resources to the grid. The new resources are expected to comprise of about 535 MW of wind, 985 MW of natural-gas-fired generation, 108 MW of hydroelectric, and 83 MW of solar.

Capacity Transfers: As part of the electricity trade agreement between Ontario and Quebec, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023.

Transmission: In anticipation of the Pickering nuclear generation retirement, a new 500/230 kV autotransformer station, Clarington TS, came into service east of the Greater Toronto Area (GTA) in 2018. This new facility is critical to maintaining system and supply reliability in Eastern GTA following the shutdown of the Pickering generating units. In Northwestern Ontario, a new 400–450 km long 230 kV double-circuit transmission line (the East–West Tie) is planned to come into service in 2020. The new line will reinforce the connection of Northwestern Ontario to the rest of the provincial grid and will provide reliable and cost-effective, long-term supply to this area. Other system improvements that have been planned or are under study include the installation of 500 kV line-connected shunt reactors at Lennox GS in Eastern Ontario, to mitigate high system voltages under low demand/low transfer periods, and a review of major equipment, such as phase-shifters and regulators on Ontario's interconnections with New York and Michigan as some of the facilities are approaching their end of service life.



NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of eight million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVDC ties, radial generation, or load to and from neighboring systems.

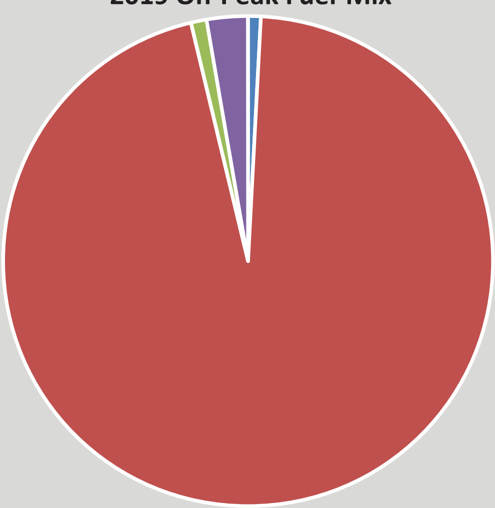
Highlights

- Approximately 400 MW of capacity additions are expected over the assessment period.
- A total of 500 MW of firm import capacity is now available each winter until March 2023 due to a new electricity trade agreement between Québec and Ontario.
- The Chamouchouane to Montréal 735 kV Line is under construction and will be in service by 2019.

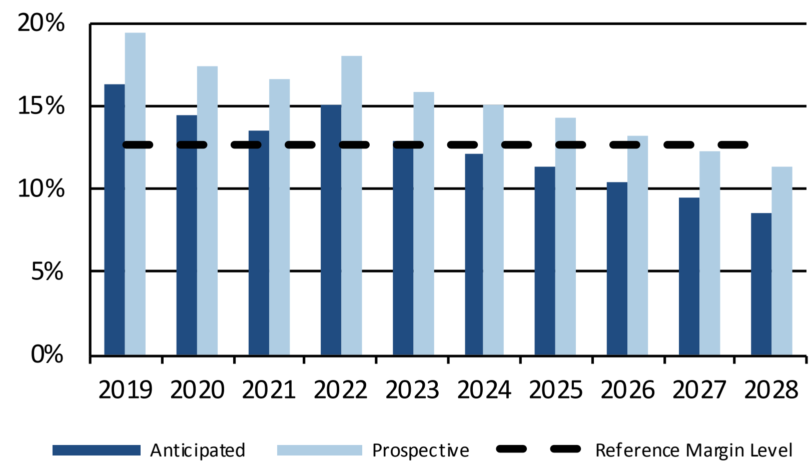
Demand, Resources, and Reserve Margins (MW)

Quantity	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Total Internal Demand	38,782	39,057	39,427	39,737	40,016	40,288	40,561	40,817	41,059	41,311
Demand Response	2,424	2,454	2,504	2,534	2,544	2,564	2,574	2,574	2,574	2,574
Net Internal Demand	36,359	36,604	36,924	37,203	37,473	37,724	37,987	38,243	38,486	38,737
Additions: Tier 1	55	397	397	397	397	397	397	397	397	397
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	202	-541	-499	355	-145	-145	-145	-145	-145	-145
Existing-Certain and Net Firm Transfers	42,248	41,505	41,547	42,401	41,893	41,893	41,902	41,805	41,723	41,659
Anticipated Reserve Margin (%)	16.35	14.48	13.60	15.04	12.86	12.10	11.35	10.35	9.44	8.57
Prospective Reserve Margin (%)	19.37	17.48	16.58	18.00	15.79	15.02	14.25	13.23	12.30	11.41
Reference Margin Level (%)	12.61	12.61	12.61	12.61	12.61	12.61	12.61	12.61	12.61	12.61

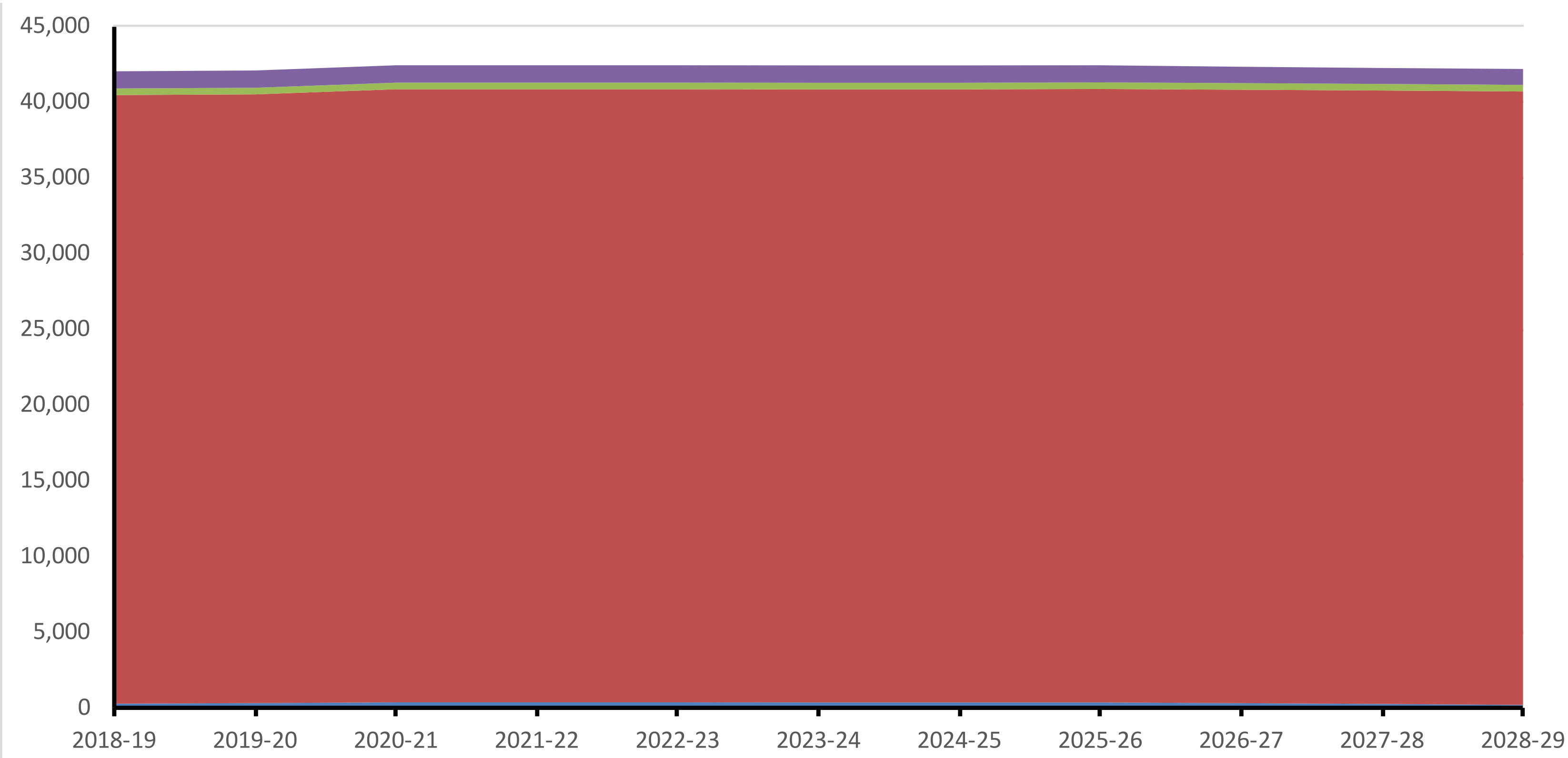
2019 On-Peak Fuel-Mix



Generation Type	2019–2020		2028–2029	
	MW	Percent	MW	Percent
Biomass	352	1%	232	1%
Hydro	40,173	95%	40,484	96%
Petroleum	436	1%	436	1%
Wind	1,140	3%	1,050	2%
Total	42,101	100%	42,201	100%



Planning Reserve Margins



NPCC-Québec Fuel Composition

Gen Type	2019–2020	2020–2021	2021–2022	2022–2023	2023–2024	2024–2025	2025–2026	2026–2027	2027–2028	2028–2029
Biomass	352	403	403	403	395	395	395	347	295	232
Hydro	40,173	40,459	40,459	40,459	40,459	40,459	40,484	40,484	40,484	40,484
Petroleum	436	436	436	436	436	436	436	436	436	436
Wind	1,140	1,146	1,146	1,146	1,146	1,146	1,129	1,080	1,050	1,050
Total	42,101	42,443	42,443	42,443	42,435	42,435	42,444	42,347	42,265	42,201

Probabilistic Assessment Overview

- **General Overview:** The Québec area is a winter-peaking area. No significant LOLH was observed. The estimated EUE is negligible. THe Anticipated Reserve Margins are above the 12.6 percent Reference Margin for both 2020 and 2022. Any contribution to the LOLH and EUE occurs during the peak (winter) monthly period.
- **Modeling:** Assumptions used in this ProbA are consistent with those used in *NPCC 2018 Long Range Adequacy Overview.*[1] The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion:[2]
    - The Québec demand forecast is built on the forecast from four different consumption sectors—domestic, commercial, small and medium-size industrial, and large industrial. The model types used in the forecasting process are different for each sector and are based on end-use and/or econometric models. They consider weather variables, economic-driver forecasts, demographics, energy efficiency, and different information about large industrial customers. This forecast is normalized for weather conditions based on an historical trend weather analysis.
    - For thermal units, maximum capacity in the Québec area is defined as the net output a unit can sustain over a two-consecutive hour period.
    - In Québec, hydro resources maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.
    - In Québec, behind-the-meter generation (solar and wind) is estimated at 1.5 MW and doesn't affect the load monitored from a network perspective.
    - In Québec, the expected capacity at winter peak is 30 percent of the Installed (nameplate) capacity except for a small amount (roughly three percent) that is derated for all years of the study. For the summer period, wind power generation is derated by 100 percent.
- **Probabilistic vs. Deterministic Assessments:** Details regarding the differences between the probabilistic and deterministic representations can be found in the *NERC 2018 Probabilistic Assessment – NPCC Region*:[3]
    - The loads for each area were modeled on an hourly, chronological basis, based on the 2002 load shape for the summer period and the 2003/04 load shape for the winter period.[4]
    - Québec modeled operating procedures that include reduced operating reserves, voltage reduction, and interruptible load programs before firm load has to be disconnected.
    - DR programs in Québec are specifically designed for peak-load reduction during winter operating periods are mainly interruptible load programs.
    - Transmission additions and retirements assumed were consistent with this *NERC 2018 LTRA*.
    - In the NPCC ProbA simulations, all areas received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously in all areas and subareas.

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1 https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

2 https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

3 Available December 2018 at the following: https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

4 https://www.npcc.org/Library/Other/Forms/Public20List.aspx

Base Case Study

- **Results Trending:** The previous study *NERC Probabilistic Assessment – NPCC Region* estimated an annual LOLH = 0.000 hours/year and a corresponding EUE equal to 0.0 (ppm) for the year 2020.* The Forecast 50/50 peak demand is slightly higher than reported in the previous study with lower estimated forecast planning and forecast operable reserve margins. There is no change in the estimated LOLH and EUE in this year's study.

Summary of Results			
Reserve Margin			
	2020*	**2020**	**2022**
Anticipated	15.8	14.5	15.0
Reference	12.7	12.6	12.6
ProbA Forecast Operable	14.2	9.5	7.1
Annual Probabilistic Indices			
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: The Anticipated Reserve Margin is below the Reference Margin Level for the last five winter seasons of the assessment period. Under this scenario, the Quebec area has no firm imports and purchases from neighboring areas that would be needed to maintain the Reference Margin Level. The Prospective Reserve Margin remains above the Reference Margin Level for all seasons and years during the assessment period except for the last two winter periods. Three years prior to these upcoming winters, the area will launch a call for tenders in order to overcome its capacity needs. Under the Prospective scenario, a total of 1,100 MW of expected capacity imports are planned by the Québec area. These purchases have not yet been backed by firm long-term contracts. However, on a yearly basis, the Québec area proceeds with short-term capacity purchases in order to meet its capacity requirements if needed.

Demand: The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand. The Quebec area demand forecast average annual growth is 0.7 percent during the 10-year period, similar to last year's forecast.

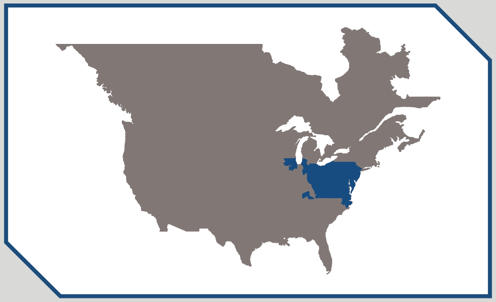
Demand-Side Management: The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program, mainly designed for large industrial customers; it has an impact of 1,784 MW on peak demand. The second type of DR resource consists of a voltage reduction scheme that has a 250 MW of demand reduction at peak. Finally, the area continues to develop new DR programs, including direct control load management and others. A new program that consists mostly of interruptible charges in commercial buildings has shown great results. This program has an anticipated impact of 320 MW in 2018-19 and should reach 540 MW by 2025–26. Energy efficiency will also continue to grow over the entire assessment period. Energy efficiency and conservation programs are integrated in the assessment area's demand forecasts.

Distributed Energy Resources: Behind the meter generation (including solar PV) is around 1.5 MW and is accounted for in the load forecast.

Generation: Work is underway on the Romaine-4 unit (245 MW), which is expected to be fully operational in 2020. No retrofitting of hydro units is considered over the assessment period. The integration of small hydro units also accounts for 54 MW of new capacity during the assessment period. For other renewable resources, about 371 MW (111 MW on-peak value) of wind capacity has been added to the system since the beginning of 2017 and 43 MW (13 MW on-peak value) is expected to be in service by 2021. Additionally, about 22 MW of biomass was also commissioned in 2017 and 89 MW of new biomass is expected to be in service by 2021.

Capacity Transfers: Since 2011, the power transmission system has undergone significant changes: reduced consumption in the Côte-Nord area and decommissioning of the Tracy and La Citière thermal and Gentilly-2 nuclear generating station. These changes have brought about an increase to the power flow on the lines of the Manic-Québec corridor toward the major load centres and decreased the reliability of the transmission system. Hydro-Québec is thus required to take steps in order to restore adequate transmission capacity to the corridor and maintain system reliability. After considering a number of scenarios, Hydro-Québec believes that the best solution is to build a new 735-kV line extending some 250 km (155 miles) between Micoua substation in the Côte-Nord region and Saguenay substation in Saguenay–Lac–Saint-Jean. The project also includes adding equipment to both substations and expanding Saguenay substation. Commissioning of the new equipment is planned in 2022.

Transmission: Construction of the Romaine River Hydro Complex is presently underway. Romaine-4 (245 MW) will be integrated in 2020 at the Montagnais 735/315 kV substation. The Chamouchouane to Montreal 735 kV is under construction and is being built after planning studies showed a need to reinforce the transmission system to meet the Reliability Standards. The line (about 400 km or 250 miles) will extend from the Chamouchouane substation on the eastern James Bay subsystem to Duvernay substation near Montréal. This project will reduce transfers on other parallel lines on the Southern 735-kV Interface, thus optimizing operation flexibility and reducing losses. The line was initially scheduled to be in service before the 2018-19 winter peak period but the project has been delayed to 2019.



Highlights

- Anticipated Reserve Margins will remain above the Reference Margin Level (installed reserve margin requirement) throughout the assessment period.
- Demand continues to flatten as load efficiency increases and more rooftop solar installations are added.
- PJM continues to manage an unprecedented generating capacity fuel shift from coal to natural gas.

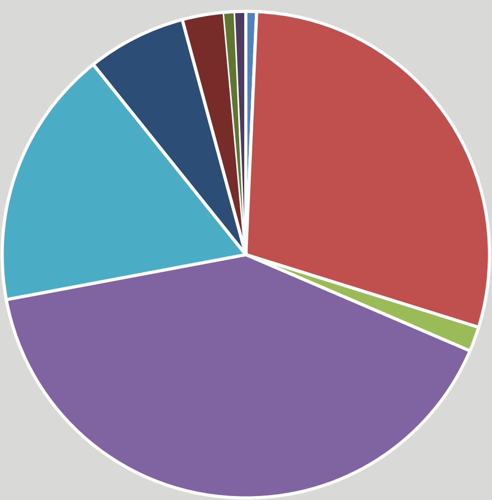
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 61 million people and covers 243,417 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

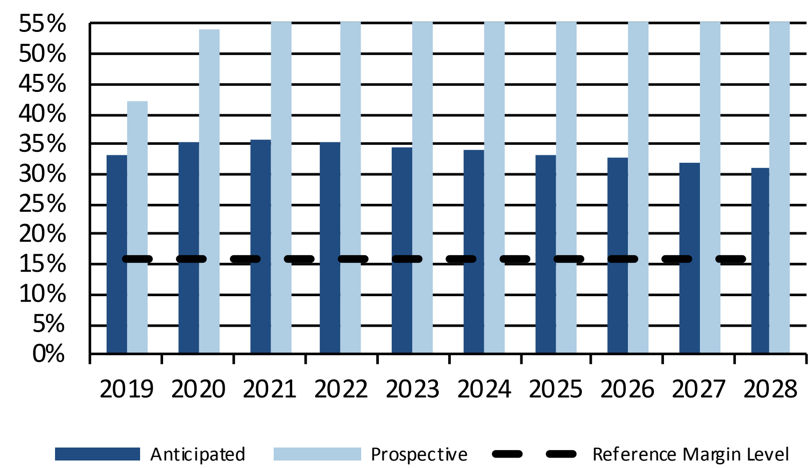
Demand, Resources, and Reserve Margins (MW)

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	152,479	151,962	152,363	152,887	153,632	154,245	154,941	155,724	156,605	157,635
Demand Response	9,113	7,675	7,691	7,721	7,747	7,786	7,823	7,862	7,899	7,947
Net Internal Demand	143,366	144,287	144,672	145,166	145,885	146,459	147,118	147,862	148,706	149,688
Additions: Tier 1	8,357	14,785	18,155	18,155	18,155	18,155	18,155	18,155	18,155	18,155
Additions: Tier 2	12,862	27,579	34,075	40,069	41,369	41,369	41,369	41,369	41,369	41,369
Net Firm Capacity Transfers	1,486	1,728	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	182,498	180,667	178,106	178,106	178,106	178,106	178,106	178,106	178,106	178,106
Anticipated Reserve Margin (%)	33.12	35.46	35.66	35.20	34.53	34.00	33.40	32.73	31.98	31.11
Prospective Reserve Margin (%)	42.10	53.95	58.30	61.27	61.36	60.73	60.01	59.21	58.30	57.26
Reference Margin Level (%)	15.90	15.90	15.80	15.80	15.80	15.80	15.80	15.80	15.80	15.80

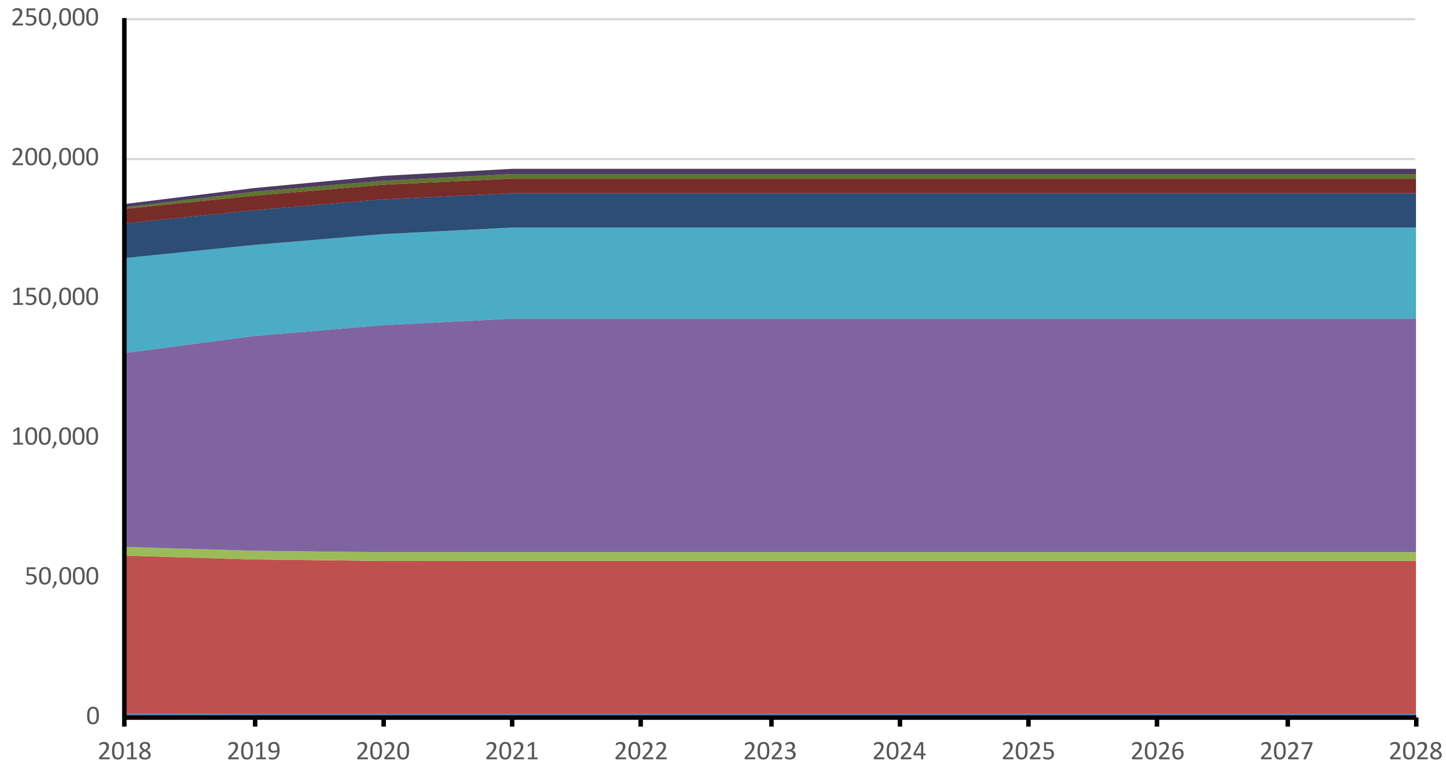
2019 On-Peak Fuel-Mix



Generation Type	2019 MW	2019 Percent	2028 MW	2028 Percent
Biomass	1,336	1%	1,336	1%
Coal	55,136	29%	54,620	28%
Hydro	3,123	2%	3,145	2%
Natural Gas	76,838	41%	83,550	43%
Nuclear	32,559	17%	32,560	17%
Other	20	0%	20	0%
Petroleum	12,425	7%	12,296	6%
Pumped Storage	5,229	3%	5,229	3%
Solar	1,376	1%	1,659	1%
Wind	1,327	1%	1,845	1%
Total	54,586	100%	58,436	100%



Planning Reserve Margins



PJM Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336
Coal	55,136	54,597	54,620	54,620	54,620	54,620	54,620	54,620	54,620	54,620
Hydro	3,123	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145
Natural Gas	76,838	81,235	83,550	83,550	83,550	83,550	83,550	83,550	83,550	83,550
Other	32,559	32,560	32,560	32,560	32,560	32,560	32,560	32,560	32,560	32,560
Nuclear	20	20	20	20	20	20	20	20	20	20
Petroleum	12,425	12,431	12,296	12,296	12,296	12,296	12,296	12,296	12,296	12,296
Pumped Storage	5,229	5,229	5,229	5,229	5,229	5,229	5,229	5,229	5,229	5,229
Solar	1,376	1,431	1,659	1,659	1,659	1,659	1,659	1,659	1,659	1,659
Wind	1,327	1,739	1,845	1,845	1,845	1,845	1,845	1,845	1,845	1,845
Total	189,370	193,724	196,261	196,261	196,261	196,261	196,261	196,261	196,261	196,261

Probabilistic Assessment Overview

- **General Overview:** The ProbA was carried out in GE-MARS using Monte Carlo simulation. Internal and external load shapes were from year 2002 (Summer) and 2004 (Winter) and adjusted to match monthly and annual peak forecast values from the 2018 PJM load forecast. Data on individual unit performance is from the period 2013–2017, and PJM was divided in five subareas interconnected using a transportation/pipeline approach. External areas were modeled using a detailed representation and at planned reserve margin (NPPC, MISO, TVA, VACAR).
- **Modeling:** Load forecast uncertainty was modeled on a monthly basis using a normal distribution discretized into seven partitions and their associated probabilities. DSM was modeled as an emergency operating procedure as most of the DSM in PJM is emergency DSM. Intermittent generators were modeled as a regular resource at their respective capacity values (average capacity value for wind is 13 percent while solar is 38 percent). Firm exports/imports were explicitly modeled while the limits on the transportation/pipeline interfaces were calculated based on a first contingency total transfer capability analysis.
- **Results Trending:** The 2020 LOLH and EUE in the 2018 ProbA are similar to the corresponding values reported in the 2016 ProbA:
  - 2020 LOLH in 2018 ProbA = 0.000 hrs/year vs. 2020 LOLH in 2016 ProbA = 0.000 hrs/year
  - 2020 EUE in 2018 ProbA = 0.000 MWh/year vs. 2020 EUE in 2016 ProbA = 0.001 MWh/year
- **Probabilistic vs. Deterministic Assessments:** For Summer 2020 and Summer 2022, the probabilistic reserve margin in slightly lower than the deterministic value due to 2,500 MW of on-peak capacity derates as a result of above average summer ambient conditions.

Base Case Study

- LOLH and EUE are zero for both 2020 and 2022 due to large forecast planning reserve margins. The reserve margins are significantly above the reference values of 15.9 percent and 15.8 percent, respectively.

Summary of Results		
Reserve Margin		
	Base Case	
	2020	**2022**
Anticipated	35.5	35.2
Prospective	53.9	61.3
Reference	15.9	15.8
ProbA Forecast Planning	33.7	33.5
ProbA Forecast Operable	22.7	22.5
Annual Probabilistic Indices		
	Base Case	
	2020	**2022**
EUE (MWh)	0.000	0.000
EUE (ppm)	0.000	0.000
LOLH (hours/year)	0.000	0.000

Planning Reserve Margins: The IRM, applied as the Reference Margin Level, for the delivery year beginning on June 1, 2018, is 16.7 percent and drops to 16.6 percent for the 2019 delivery year and beyond.

Demand: The PJM Interconnection produces an independent peak load demand forecast using econometric regression models with daily load as the dependent variable and independent variables, including calendar effects, weather, economics, and end-use characteristics. Daily unrestricted peak load is defined as metered load plus estimated load drops and estimated distributed solar generation. No reliability problems are anticipated due to the overall 0.2 percent summer load growth.

Demand-Side Management: DSM providers have the ability to participate in PJM reliability pricing model (RPM) auctions up to three years in advance of the delivery year (PJM delivery year (DY) is June–May). DSM providers may register DR locations in DRHUB to meet their RPM commitments starting January of the year in which the new DY starts. For the DY 2016/17, DSM providers offering DR resources into RPM have an overall RPM commitment of 8,336 MW of load reductions. DR registrations participating in the capacity market are to respond according to real-time emergency procedures, if called upon.

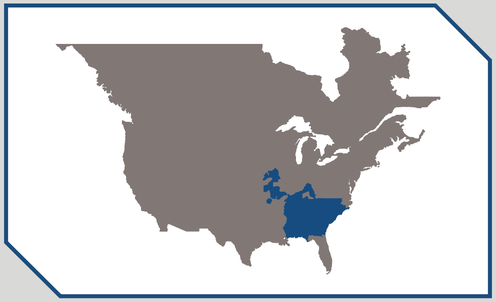
Distributed Energy Resources: In early 2015, recognizing the growing market of solar installations, PJM began to investigate and develop a plan to incorporate distributed solar generation into the long-term load forecast. Environmental Information Services, a wholly owned subsidiary of PJM Technologies, Inc., which is a subsidiary of PJM Interconnection, operates the Generation Attribute Tracking System. The generation data that the Generation Attribute Tracking System collects includes distributed solar generation that is behind-the-meter. Utilizing this collection of data, PJM estimates the amount of distributed solar generation in terms of dc nameplate capacity. In the last five years, there has been over a 1,000 percent increase of installations in the PJM Region, and the number of installations is expected to continue to grow with a nameplate value of over 11,700 MW in 2027.

Generation: PJM's regional transmission expansion plan (RTEP)[64] process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics: new generating plants powered by Marcellus and Utica shale natural gas, new wind and solar units driven by federal and state renewable incentives, generating plant deactivations, and market impacts introduced by demand resources and energy efficiency programs. Natural-gas-fired generation capacity now exceeds coal in PJM. Natural gas plants total over 65,600 MW and comprise of 86 percent of the generation currently seeking capacity interconnection rights in PJM's new generation queue. As for coal, if formally submitted deactivation plans materialize, more than 25,000 MW of coal-fired generation will have deactivated between 2011 and 2020. The economic impacts of environmental public policy coupled with the age of these plants make ongoing operation prohibitively expensive. To offset lower solar generation during winter peak periods, PJM will allow higher (if historically proven) wind capacity factors.

Capacity Transfers: PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer into PJM would amount to less than two percent of PJM's internal generation capability. At no time within this assessment period do anticipated transfers amount anywhere near two percent.

Transmission: PJM's RTEP process identifies transmission system additions and improvements needed to serve more than 65 million people throughout 13 states and the District of Columbia. Doing so gives PJM the ability to identify one optimal, comprehensive set of solutions to resolve reliability criteria violations, operational performance issues, and congestion constraints. Specific system enhancements are justified to meet local reliability requirements and deliver needed power to more distant load centers. Once the PJM Board approves recommended system enhancements—new facilities and upgrades to existing ones—they formally become part of PJM's overall RTEP.

[64] PJM RTEP: https://www.pjm.com/planning/rtep-development.aspx



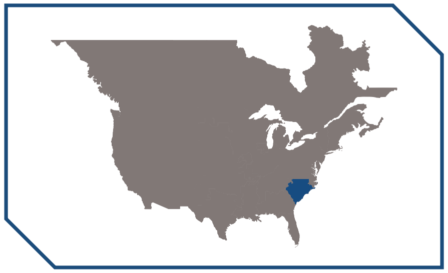
SERC

SERC is a summer-peaking assessment area that covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC is divided into three assessment areas: SERC-E, SERC-N, and SERC-SE. The SERC Region includes 11 Balancing Authorities: Alcoa Power Generating, Inc.–Yadkin Division (Yadkin), Associated Electric Cooperative, Inc. (AECI), Duke Energy Carolinas and Duke Energy Progress (Duke), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU)), PowerSouth Energy Cooperative (PowerSouth), South Carolina Electric & Gas Company (SCE&G), South Carolina Public Service Authority (Santee Cooper, SCPSA), Southern Company Services, Inc. (Southern), and Tennessee Valley Authority (TVA).

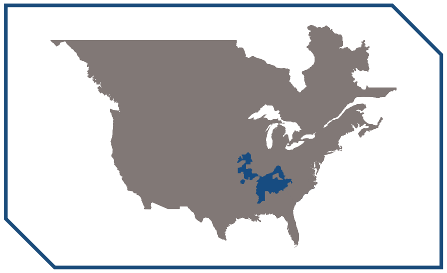
Highlights

- Approximately 21 GW of utility-scale transmission BES-connected solar projects are expected in the interconnection queue over the next five years, developing mostly in SERC-E.
- Due to increased winter weather loads (e.g., Polar Vortex, extreme cold weather snaps), entities are reviewing and modifying winter reliability related assumptions (xload forecast, reserve margins).
- SERC assessment areas will transition from NERC's Reference Margin Levels (15 percent) to SERC reserve margins targets developed from SERC's probabilistic assessment biennial studies.

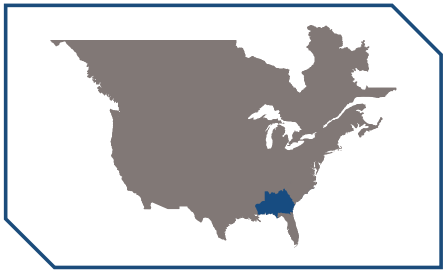
Starting on the next page are summaries of the assessment areas that make up SERC.



SERC-E

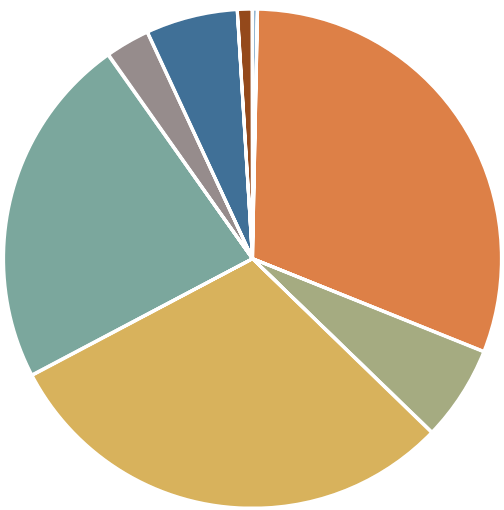


SERC-N



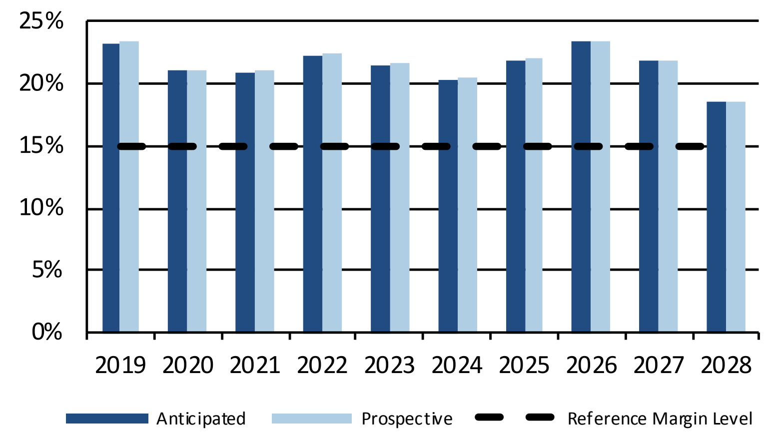
SERC-SE

Demand, Resources, and Reserve Margins (MW)										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	42,684	43,162	43,523	43,902	44,227	44,632	45,010	45,445	45,876	46,375
Demand Response	1,090	1,091	1,093	1,093	1,093	1,094	1,095	1,096	1,098	1,099
Net Internal Demand	41,594	42,071	42,430	42,809	43,134	43,538	43,915	44,349	44,778	45,276
Additions: Tier 1	7	608	608	1,759	1,759	1,759	2,910	4,061	4,061	4,282
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	184	-155	184	25	25	25	25	25	25	25
Existing-Certain and Net Firm Transfers	51,271	50,317	50,704	50,591	50,638	50,642	50,642	50,644	50,468	49,370
Anticipated Reserve Margin (%)	23.28	21.05	20.93	22.29	21.48	20.36	21.94	23.35	21.78	18.50
Prospective Reserve Margin (%)	23.38	21.14	21.03	22.39	21.57	20.45	22.04	23.45	21.87	18.59
Reference Margin Level (%)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

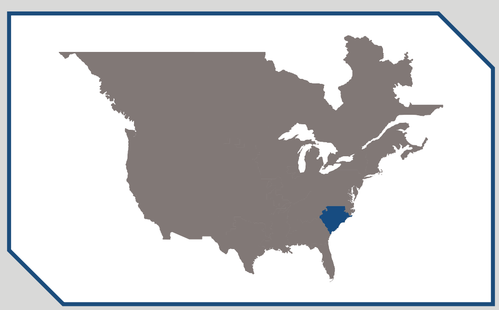


2019 On-Peak Fuel-Mix

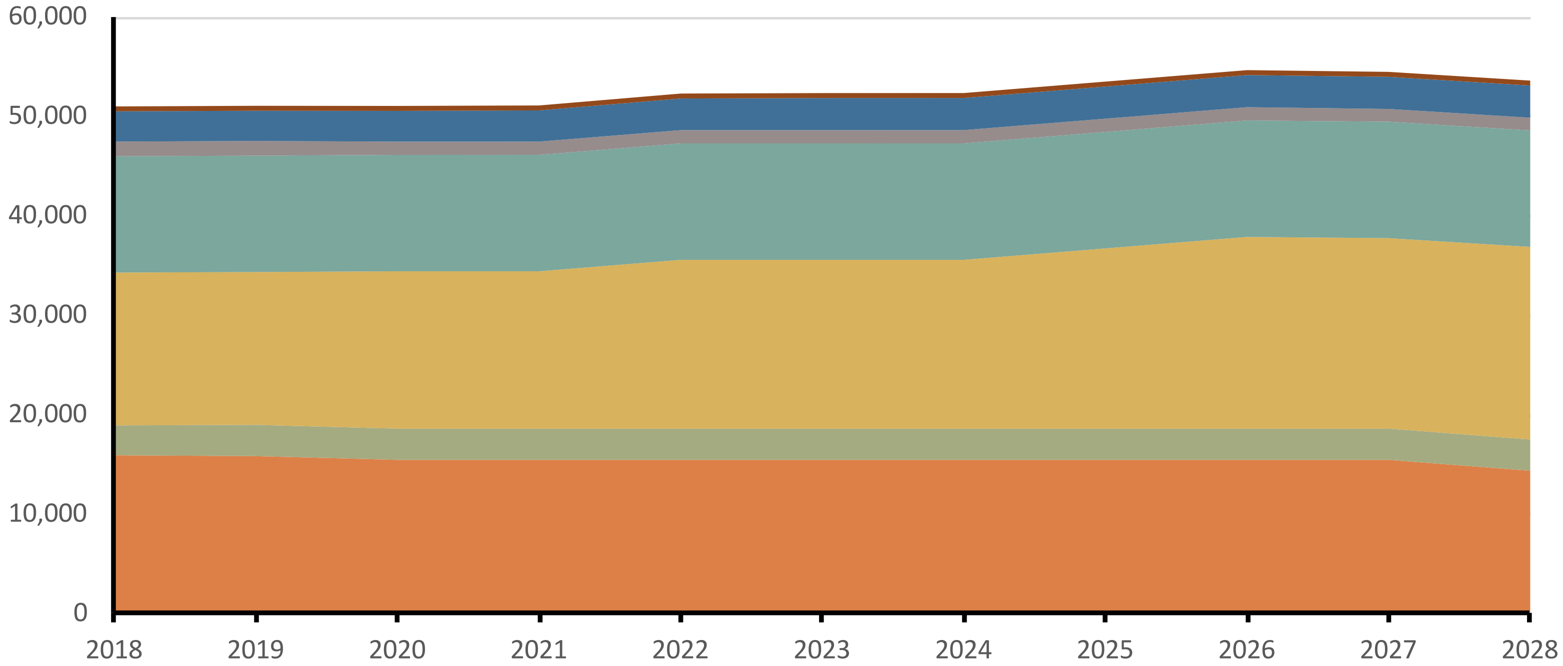
Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	164	0%	164	0%
Coal	15,709	31%	14,233	27%
Hydro	3,143	6%	3,143	6%
Natural Gas	15,363	30%	19,368	36%
Nuclear	11,699	23%	11,711	22%
Petroleum	1,475	3%	1,282	2%
Pumped Storage	3,044	6%	3,230	6%
Solar	497	1%	497	1%
Total	51,094	100%	53,627	100%



SERC-E Planning Reserve Margins



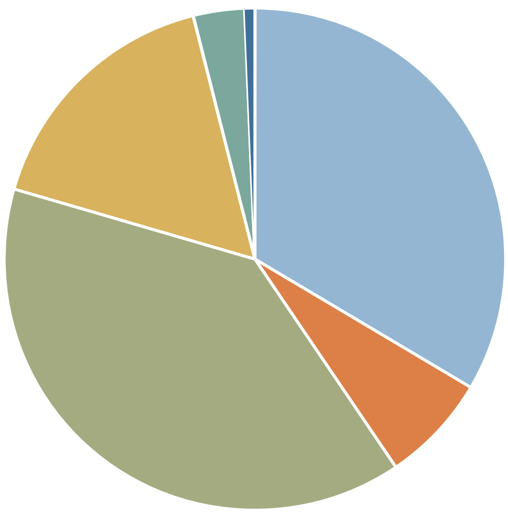
SERC-E



SERC-E Fuel Composition

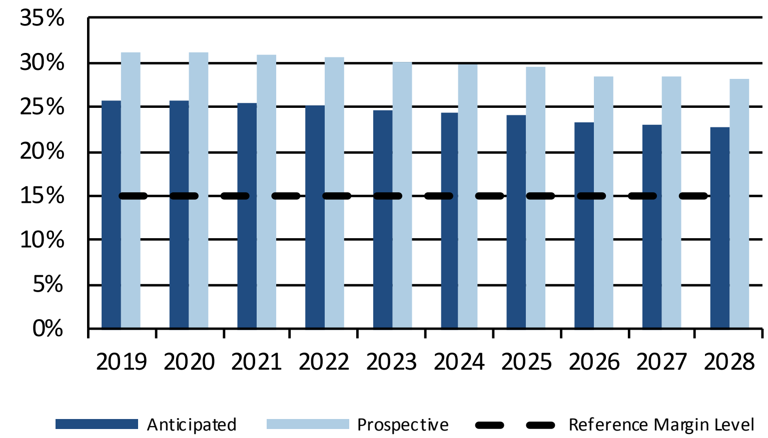
Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	164	164	164	164	164	164	164	164	164	164
Coal	15,709	15,331	15,331	15,331	15,331	15,331	15,331	15,331	15,331	14,233
Hydro	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143
Natural Gas	15,363	15,818	15,818	16,969	16,969	16,969	18,120	19,271	19,147	19,368
Nuclear	11,699	11,703	11,705	11,705	11,705	11,709	11,709	11,711	11,711	11,711
Petroleum	1,475	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,282	1,282
Pumped Storage	3,044	3,090	3,137	3,183	3,230	3,230	3,230	3,230	3,230	3,230
Solar	497	497	497	497	497	497	497	497	497	497
Total	51,094	51,080	51,128	52,326	52,372	52,376	53,527	54,680	54,504	53,627

Demand, Resources, and Reserve Margins (MW)										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	41,526	41,730	41,784	41,851	42,001	42,025	42,143	42,414	42,486	42,547
Demand Response	1,795	1,795	1,802	1,759	1,705	1,671	1,666	1,666	1,666	1,666
Net Internal Demand	39,731	39,935	39,982	40,092	40,296	40,354	40,477	40,748	40,820	40,881
Additions: Tier 1	0	0	0	0	0	0	0	0	0	0
Additions: Tier 2	68	68	68	68	68	68	68	68	68	68
Net Firm Capacity Transfers	-1,057	-952	-952	-952	-952	-952	-952	-952	-952	-952
Existing-Certain and Net Firm Transfers	49,943	50,201	50,201	50,201	50,201	50,201	50,201	50,201	50,201	50,201
Anticipated Reserve Margin (%)	25.70	25.71	25.56	25.21	24.58	24.40	24.02	23.20	22.98	22.80
Prospective Reserve Margin (%)	31.22	31.20	31.04	30.68	30.02	29.84	29.44	28.58	28.35	28.16
Reference Margin Level (%)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

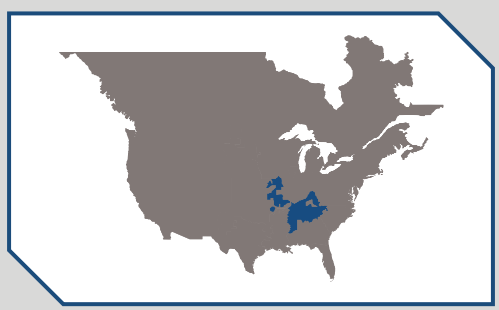


2019 On-Peak Fuel-Mix

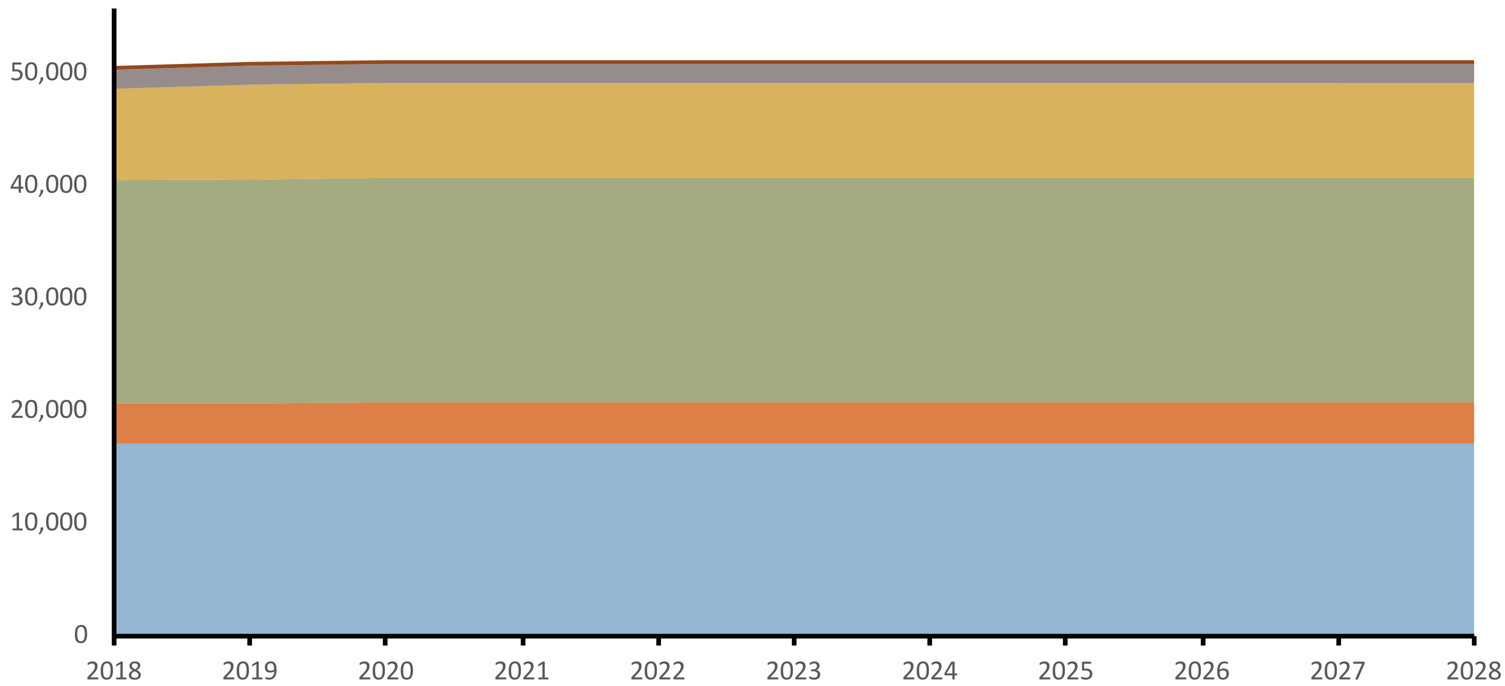
Generation Type	2019		2028	
	MW	Percent	MW	Percent
Coal	17,097	34%	17,097	33%
Hydro	3,566	7%	3,647	7%
Natural Gas	19,885	39%	19,957	39%
Nuclear	8,431	17%	8,431	16%
Pumped Storage	1,680	3%	1,680	3%
Solar	8	0%	8	0%
Wind	333	1%	333	1%
Total	51,094	100%	53,627	100%



SERC-N Planning Reserve Margins



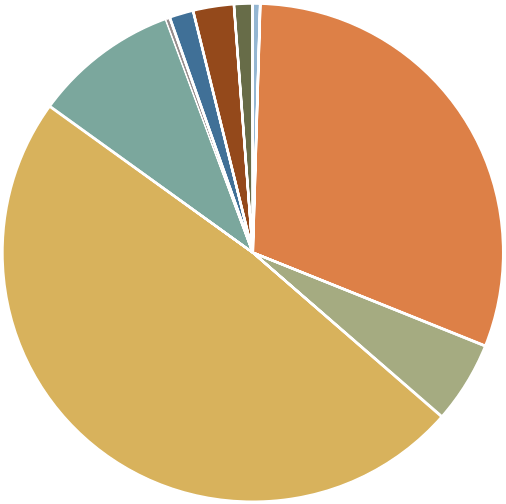
SERC-N



SERC-N Fuel Composition

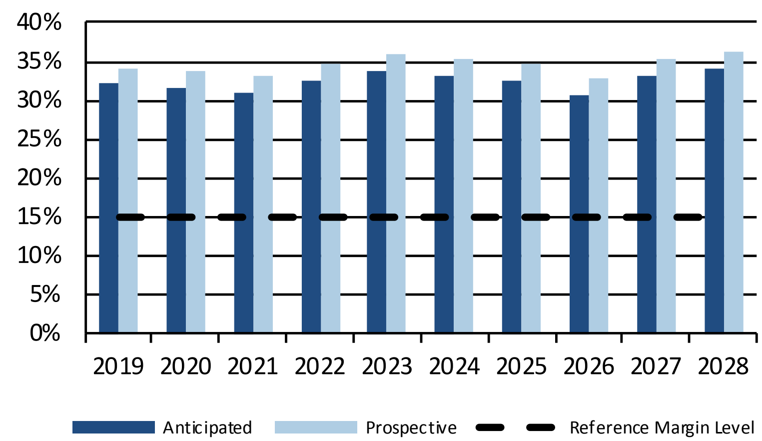
Gen Type		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Coal		17,097	17,097	17,097	17,097	17,097	17,097	17,097	17,097	17,097	17,097
Hydro		3,566	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647
Natural Gas		19,885	19,957	19,957	19,957	19,957	19,957	19,957	19,957	19,957	19,957
Nuclear		8,431	8,431	8,431	8,431	8,431	8,431	8,431	8,431	8,431	8,431
Pumped Storage		1,680	1,680	1,680	1,680	1,680	1,680	1,680	1,680	1,680	1,680
Solar		8	8	8	8	8	8	8	8	8	8
Wind		333	333	333	333	333	333	333	333	333	333
Total		51,000	51,153	51,153	51,153	51,153	51,153	51,153	51,153	51,153	51,153

Demand, Resources, and Reserve Margins										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	47,896	48,085	48,260	48,508	48,765	49,039	49,304	49,980	49,080	48,712
Demand Response	2,101	2,102	2,102	2,102	2,103	2,103	2,103	2,104	2,104	2,105
Net Internal Demand	45,795	45,983	46,158	46,406	46,662	46,936	47,201	47,876	46,976	46,607
Additions: Tier 1	164	164	164	1,264	2,364	2,364	2,364	2,364	2,364	2,364
Additions: Tier 2	100	100	198	198	198	198	198	198	198	198
Net Firm Capacity Transfers	-1,426	-1,406	-1,534	-1,560	-1,744	-1,722	-1,649	-1,645	-1,643	-1,641
Existing-Certain and Net Firm Transfers	60,354	60,383	60,265	60,239	60,055	60,077	60,150	60,154	60,156	60,158
Anticipated Reserve Margin (%)	32.15	31.67	30.92	32.53	33.77	33.03	32.44	30.58	33.09	34.15
Prospective Reserve Margin (%)	34.25	33.76	33.21	34.82	36.04	35.29	34.69	32.80	35.34	36.42
Reference Margin Level (%)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

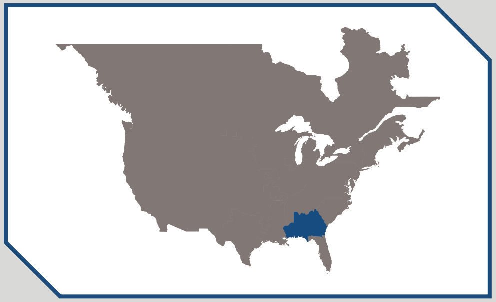


2019 On-Peak Fuel-Mix

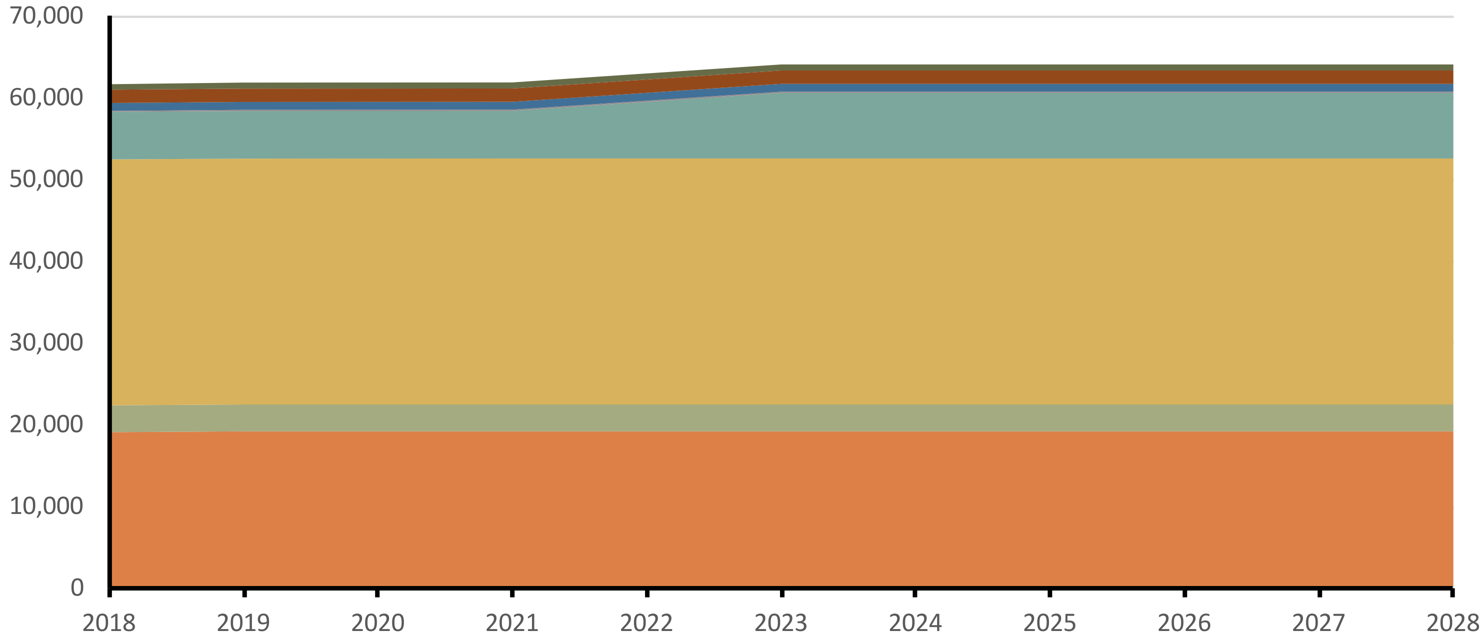
Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	289	0%	289	0%
Coal	18,979	31%	18,979	30%
Hydro	3,288	5%	3,288	5%
Natural Gas	30,083	49%	30,102	47%
Nuclear	5,818	9%	8,018	12%
Other	153	0%	153	0%
Petroleum	961	2%	961	1%
Pumped Storage	1,632	3%	1,632	3%
Solar	740	1%	740	1%
Total	61,944	100%	64,162	100%



SERC-SE Planning Reserve Margins



SERC-SE



SERC-SE Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	289	289	289	289	289	289	289	289	289	289
Coal	18,979	18,979	18,979	18,979	18,979	18,979	18,979	18,979	18,979	18,979
Hydro	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288
Natural Gas	30,083	30,092	30,102	30,102	30,102	30,102	30,102	30,102	30,102	30,102
Nuclear	5,818	5,818	5,818	6,918	8,018	8,018	8,018	8,018	8,018	8,018
Other	153	153	153	153	153	153	153	153	153	153
Petroleum	961	961	961	961	961	961	961	961	961	961
Pumped Storage	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632
Solar	740	740	740	740	740	740	740	740	740	740
Total	61,944	61,953	61,962	63,062	64,162	64,162	64,162	64,162	64,162	64,162

SERC-E Probabilistic Assessment Overview

- **General Overview:** Lowering demand projections in SERC East (SERC-E) continue to increase Anticipated Reserve Margins and decrease the resource adequacy measures in the assessment area (3.5 percent decrease from 2016 to 2018 in study year 2020 demand forecast). Additionally, with an 11.5 percent increase in natural gas generation expected on peak by 2022, reserve margins in SERC E consistently trend above 20 percent, leading to zero megawatts of expected loss of load.
- **Modeling:** SERC utilizes General Electric MARS software, an 8760 hourly load, generation, and transmission sequential Monte Carlo simulation model consisting of 15 interconnected areas, three of which are SERC's NERC assessment areas (SERC-E, SERC-N, and SERC-SE):
    - Annual peak demand in SERC-E varies by ± five percent of forecasted SERC-E demand based upon the 90/10 percent points of LFU distributions.
    - Thermal units in SERC-E follow a two-state on-or-off sequence based on a Monte Carlo simulation that utilizes unit class average forced outage rates and failure durations that are equivalent to derating SERC-E thermal generating resources by six percent on average.
    - Hydro units in SERC-E follow a 20 percent dispatch 80 percent remaining energy-limited schedule. This is equivalent to limiting hydro by 18 percent maximum annual output.
    - Variable energy resources (wind and solar) in SERC-E are a load modifier based on 8,760 time series correlation to load, which is 38 percent solar capacity credit.
- **Probabilistic vs. Deterministic Assessments:** Since both assessments utilize identical capacity megawatts (existing certain and Tier 1) for thermal generation and determining exact on-peak capacity availability from the ProbA model is difficult, SERC assumes that the Anticipated Reserve Margin is the same as the ProbA forecast Planning Reserve Margin. However, the SERC-E ProbA has the following differences from the SERC-E LTRA, not already captured in the modeling section above:
    - SERC-E annual peak demand is coincident in the ProbA model (98.6 percent diversity factor) since SERC conducts LFU analysis on coincident peak demands.
    - During the simulation, the monthly peak that the SERC-E area varies with the actual monthly peak experienced during the year randomly chosen from seven annual hourly profiles input into the model (years 2007–2013). The peak months for these annual hourly profiles include three in August, two in July, and one each in February and December.
    - Total controllable DR is treated as a capacity resource with performance rates based on historical demand reduction realization (approximately 76 percent availability for SERC-E).
    - Simultaneous transfer analysis sets interface limits and flows for SERC-E average 535 MW in and 214 MW out.

Base Case Study

- SERC-E resource adequacy measures are zero in the Base Case, indicating that anticipated reserves above 24 percent lead to no expected loss of load or EUE.

Results Trending: From 2016–2018, the SERC-E 2020 LOLH decreased from 0.002 to 0.000 primarily driven by lower projected demand mentioned above.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	2020	2022
Anticipated	16.1	27.5	24.9
Prospective	15.0	13.2	14.4
Reference	11.2	20.2	18.0
Annual Probabilistic Indices			
	Base Case		
	2020*	2020	2022
EUE (MWh)	49.39	0.00	0.00
EUE (ppm)	0.22	0.00	0.00
LOLH (hours/year)	0.05	0.00	0.00

*Represents 2016 ProbA results for 2020.

SERC-N Probabilistic Assessment Overview

- **General Overview:** Lowering demand projections in SERC North (SERC-N) continue to increase Anticipated Reserve Margins and decrease the resource adequacy measures in the assessment area (3.9 percent decrease from 2016 to 2018 in the study year 2020 demand forecast). Additionally, with anticipated generation resources in the area reported to stay constant over the 10-year period planning horizon, reserve margins in SERC N consistently trend above 20 percent, leading to zero megawatts of expected loss of load.
- **Modeling:** SERC utilizes General Electric MARS software an 8,760 hourly load, generation, and transmission sequential Monte Carlo simulation model consisting of 15 interconnected areas, three of which are SERC's NERC assessment areas (SERC-E, SERC-N, and SERC-SE):
  - Annual peak demand in SERC-N varies by ± five percent of forecasted SERC-N demand based upon the 90/10 percent points of LFU distributions.
  - Thermal units in SERC-N follow a two-state on-or-off sequence based on Monte Carlo simulation that utilizes unit class average forced outage rates and failure durations that is equivalent to derating SERC-N thermal generating resources by six percent on average.
  - Hydro units in SERC-N follow a 20 percent dispatch 80 percent remaining energy-limited schedule. This is equivalent to limiting hydro by 45 percent maximum annual output.
  - Variable energy resources (wind and solar) in SERC-N are a load modifier based on 8,760 time series correlation to load, which is 37 percent solar capacity credit and 26 percent wind capacity credit.
- **Probabilistic vs. Deterministic Assessments:** Since both assessments utilize identical capacity megawatts (existing certain and Tier 1) for thermal generation and determining exact on-peak capacity availability from the ProbA model is difficult, SERC assumes that the Anticipated Reserve Margin is the same as the ProbA forecast Planning Reserve Margin. However, the SERC-N ProbA has the following differences from the SERC-N LTRA, not already captured in the Modeling bullet above:
  - SERC-N's annual peak demand is coincident in the ProbA model (98.7 percent diversity factor) since SERC conducts LFU analysis on coincident peak demands.
  - During the simulation, the monthly peak that the SERC-N area varies with the actual monthly peak experienced during the year randomly chosen from seven annual hourly profiles input into the model (years 2007–2013). The peak months for these annual hourly profiles include two in January, August, and July and one in June.
  - Total controllable DR is treated as a capacity resource with performance rates based on historical demand reduction realization (approximately 78 percent availability for SERC-N).
  - Simultaneous transfer analysis sets interface limits and flows for SERC-N average 265 MW in and 303 MW out.

Base Case Study

- SERC-N resource adequacy measures are zero in the Base Case, indicating that anticipated reserves above 24 percent lead to no expected loss of load or EUE.

Results Trending: From 2016 to 2018, the SERC-N 2020 LOLH and EUE remain zero. This is primarily driven by lower projected demand and steady resources over the assessment time frame.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	18.6	25.7	24.9
Prospective	15.0	13.2	14.4
Reference	18.0	18.5	17.7
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.13	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

SERC-SE Probabilistic Assessment Overview

- **General Overview:** Relatively flat load growth in SERC Southeast (SERC-SE) continues to increase Anticipated Reserve Margins and decrease the resource adequacy measures in the assessment area (0.4 percent decrease from 2016 to 2018 in study year 2020 demand forecast). Additionally, with Georgia Power's Vogtle nuclear expansion project (~2,200 MW), reserve margins in SERC-SE consistently trend above 30 percent, leading to zero megawatts of expected loss of load.
- **Modeling:** SERC utilizes General Electric MARS software, an 8,760 hourly load, generation, and transmission sequential Monte Carlo simulation model that consists of 15 interconnected areas. Three of these areas are SERC's NERC assessment areas (SERC-E, SERC-N, and SERC-SE):
  - Annual peak demand in SERC-SE varies by ± eight percent of forecasted SERC-SE demand based upon the 90/10 percent points of LFU distributions.
  - Thermal units in SERC-SE follow a two-state on-or-off sequence based on Monte Carlo simulation that utilizes unit class average forced outage rates and failure durations that on average is equivalent to derating SERC-SE thermal generating resources by 5.7 percent.
  - Hydro units in SERC-SE follow a 20 percent dispatch 80 percent remaining energy-limited schedule. This is equivalent to limiting hydro by 23 percent maximum annual output.
  - Variable energy resources (wind and solar) in SERC-SE are a load modifier based on 8,760 time series correlation to load, which is 32 percent solar capacity credit.
- **Probabilistic vs. Deterministic Assessments:** Since both assessments utilize identical capacity megawatts (existing certain and Tier 1) for thermal generation and determining exact on-peak capacity availability from the ProbA model is difficult, SERC assumes that the Anticipated Reserve Margin is the same as the ProbA forecast Planning Reserve Margin. However, the SERC-N ProbA has the following differences from the SERC-N LTRA, not already captured in the modeling section above:
  - SERC-SE annual peak demand is coincident in the ProbA model (99.6 percent diversity factor) since SERC conducts LFU analysis on coincident peak demands.
  - During the simulation, the monthly peak that the SERC-SE area varies with the actual monthly peak experienced during the year randomly chosen from seven annual hourly profiles input into the model (years 2007–2013). The peak months for these annual hourly profiles include three in August and June and one in July.
  - Total controllable DR is treated as a capacity resource with performance rates based on historical demand reduction realization (approximately 78 percent availability for SERC-SE).
  - Simultaneous transfer analysis sets interface limits and flows for SERC-SE average 606 MW in and 423 MW out.

Base Case Study

- SERC-SE resource adequacy measures are zero in the Base Case, indicating that anticipated reserves above 30 percent lead to no expected loss of load or EUE.

Results Trending: From 2016 to 2018, the SERC-SE 2020 LOLH and EUE remain zero primarily driven by lower projected demand and steady resources over the assessment time frame.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	33.4	31.3	32.4
Prospective	15.0	13.2	14.4
Reference	26.5	23.6	24.7
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: Anticipated Reserve Margins range between 26–28 percent across all assessment areas and do not fall below the 15 percent NERC Reference Margin Level. Specifically for SERC E, resources are planned and added within the assessment period to assist in maintaining the minimum planning reserve margin. With the additional 3,700 MW of natural gas generation serving as replacement generation for the cancelled VC-Summer nuclear plant (2,200 MW), SERC E reserve margins consistently trend above 20 percent.

Demand: Projected demand growth within the assessment areas have decreased to less than one percent over the years. Although some metro areas are experiencing higher growth rates compared to rural areas, entities report load reductions due to behind-the-meter distributed generation and appliance standards. These factors will continue suppressing the load in the future.

Demand Side Management: DR programs are minimal (7,300 MW) and vary amongst the assessment areas (e.g., summer load control, reserve preservation, voltage optimization, five minute, 60 minute, or instantaneous response). These programs are used to control peak demand. Throughout the year, entities monitor and evaluate each program's operational functionality to determine effectiveness and ability to provide demand reduction.

Distributed Energy Resources: Most of the DER growth in the Region has been solar. The queued amount of DERs connected to the non-BES, subtransmission system (roof-top solar, plug-in electric vehicles, etc.) is approximately 2,100 MW. Entities continue to work within SERC's committee forums to determine how to monitor and analyze DERs on the system. In 2017, SERC formed a special working group and task force to address the issues of data collection and analysis methodologies. In 2018, the committees will report on a special study that considers dynamics, power flow, and resource adequacy impacts. To date, there are no notable reliability impacts reported to the Region. However, the Region is working within its data collection processes to collect the appropriate level of data (MWs in the queue) so that these resources can be modeled and analyzed for potential impact to the system.

Generation: SERC entities have sufficient generation to meet demand over the period. New resources are expected, which include a combination of capacity purchases, new nuclear, natural gas, and combined-cycle units. Natural gas (43 percent), coal (32 percent), and nuclear (17 percent) generation are the dominant fuel types within the assessment areas. Hydro, renewables, and other fuel types (eight percent) are minimal.

Entities in SERC-E will add approximately 3,700 MW of natural gas generation over the period. SERC-SE will have an additional 2,200 MW of nuclear additions available to meet demand in 2021.[65] Overall, the assessment areas will encounter 6,100 MW of net additions and retirements over within the next 10 years. Approximately 21 GW of utility-scale transmission BES-connected solar projects are expected in the interconnection queue over the next five years, largely developing in SERC-E.[66]

No reliability issues are expected within the assessment areas, but entities are continuing to monitor the impacts of solar generators as they are added to the interconnection queue. Entities are studying winter season impact of additional solar to the resource mix and load forecast. As more behind-the-meter solar generation is added, some entities anticipate becoming winter-peaking systems, providing additional motivation to enforce winter reserve margins.

Transmission: SERC entities are expecting a total of 862 miles (i.e., 450 miles of >100 kV, 340 miles of >200 kV, 12 miles of >300 kV, 60 miles of >60kV) of transmission additions over the period. These projects are in the design/construction phase and are projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers (345/138kV, 161/500kV), reconductoring existing transmission lines, and other system reconfigurations/additions to support transmission system reliability. Entities in SERC-N are currently constructing a 500 kV substation to alleviate decreasing voltages and higher flows on lines caused by increased loads in the area. In addition, a static var compensators is planned for a 500 kV substation to support the stability of local units.

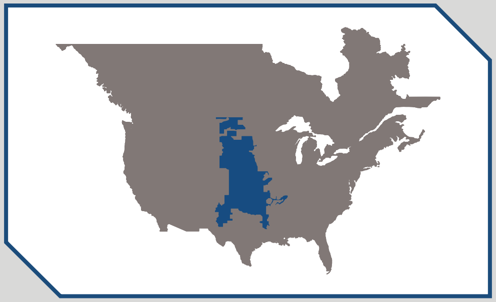
Entities coordinate transmission expansion plans during the Region's annual joint model building and study efforts. These plans are also coordinated with entities external to the Region through annual joint modeling efforts within the

[65] Based on a latest update, timing has been pushed back on Vogtle; both units will be online by 2022 (Unit #3 in 2021 and Unit #4 in 2022). This change was not incorporated into the assessment data; however, NERC evaluated the delay on Plant Vogtle and determined it did not materially change the assessment conclusions.

[66] This includes Tier 1, 2, and 3 resources.

Eastern Interconnection Reliability Assessment Group and the Multi-regional Modeling Working Group. In addition to these forums, several entities participate in open regional transmission planning processes driven by FERC Order 890. Transmission expansion plans by most SERC entities are dependent on regulatory support at the federal, state, and local levels since the regulatory entities can influence the siting, permitting, and cost recovery of new transmission facilities.

Entities do not anticipate any transmission limitations or constraints that cause significant impacts to reliability. However, limitations exist near generation sites in SERC-N and along the seams due to line loading and transfers on the transmission system. Constraints will be mitigated by future transmission projects (new builds, reactors, etc.), generation adjustments, system reconfiguration, or system purchase.



SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 575,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP Long-Term Assessment is reported based on the Planning Coordinator footprint, which touches parts of the Southwest Power Pool Regional Entity, Midwest Reliability Organization Regional Entity, and Western Electricity Coordinating Council. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations and serves a population of 18 million people.

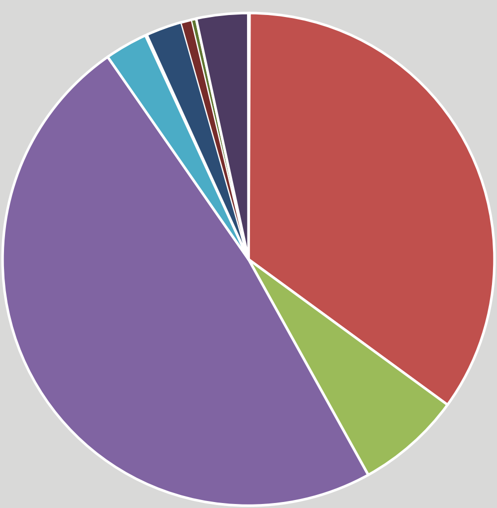
Highlights

- The Anticipated Reserve Margin for the SPP assessment area does not fall below its Reference Margin Level during the assessment period.
- There are no anticipated reliability issues from DERs given their low overall system load.
- SPP continues to see significant increase in wind penetration from a 38 percent peak in 2015 to 63.96 percent in 2018 and continues to create an operational challenges for the area.
- A few load pockets in north Texas, central Oklahoma, and northwestern Kansas require must-run generation for voltage support. Operating guides have been implemented to provide mitigation.

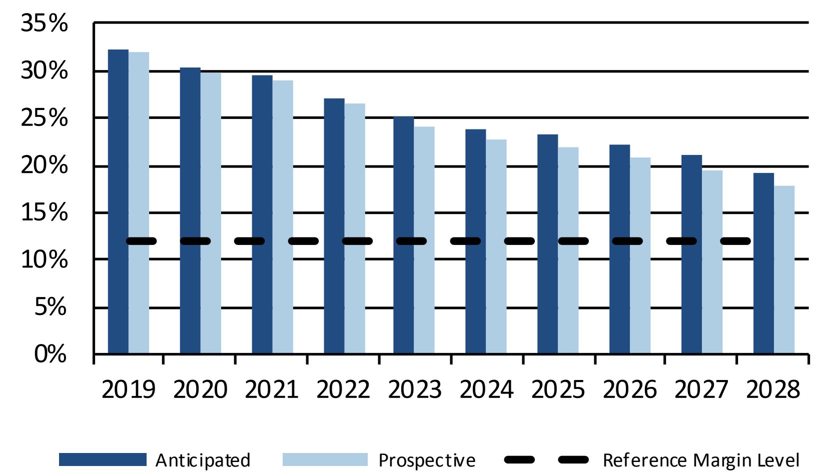
Demand, Resources, and Reserve Margins (MW)

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	52,695	52,941	53,295	54,062	54,351	54,562	54,837	55,114	55,408	55,758
Demand Response	867	897	886	868	866	868	872	877	881	885
Net Internal Demand	51,828	52,044	52,410	53,194	53,485	53,694	53,965	54,238	54,528	54,873
Additions: Tier 1	213	247	247	247	247	247	247	247	247	247
Additions: Tier 2	1	1	1	1	1	1	1	1	1	1
Net Firm Capacity Transfers	19	-569	-115	34	-81	-99	-100	-100	-100	-151
Existing-Certain and Net Firm Transfers	68,350	67,606	67,716	67,413	66,688	66,297	66,307	66,093	65,730	65,237
Anticipated Reserve Margin (%)	32.29	30.37	29.68	27.19	25.15	23.93	23.33	22.31	21.00	19.34
Prospective Reserve Margin (%)	32.06	29.81	29.12	26.65	24.06	22.85	21.94	20.94	19.63	17.90
Reference Margin Level (%)	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00

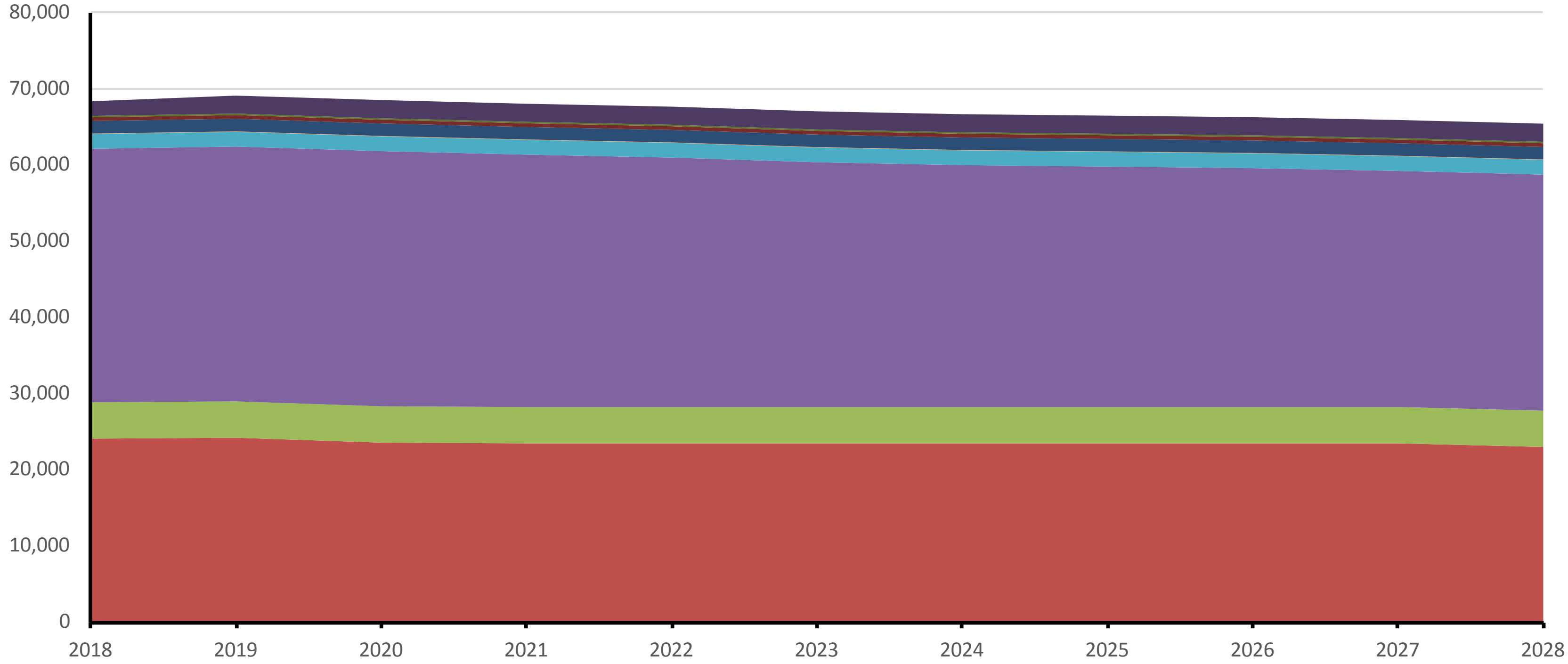
2019 On-Peak Fuel-Mix



Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	39	0%	39	0%
Coal	24,177	35%	22,970	35%
Hydro	4,770	7%	4,770	7%
Natural Gas	33,458	48%	30,983	47%
Nuclear	1,943	3%	1,943	3%
Other	52	0%	52	0%
Petroleum	1,656	2%	1,637	3%
Pumped Storage	482	1%	482	1%
Solar	197	0%	197	0%
Wind	2,359	3%	2,376	4%
Total	69,134	100%	65,450	100%



Planning Reserve Margins



SPP Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	39	39	39	39	39	39	39	39	39	39
Coal	24,177	23,536	23,439	23,439	23,439	23,439	23,439	23,439	23,439	22,970
Hydro	4,770	4,770	4,770	4,770	4,770	4,770	4,770	4,770	4,770	4,770
Natural Gas	33,458	33,499	33,136	32,747	32,134	31,756	31,566	31,361	30,998	30,983
Nuclear	1,943	1,943	1,943	1,943	1,943	1,943	1,943	1,943	1,943	1,943
Other	52	52	52	52	52	52	52	52	52	52
Petroleum	1,656	1,637	1,637	1,637	1,637	1,637	1,637	1,637	1,637	1,637
Pumped Storage	482	482	482	482	482	482	482	482	482	482
Solar	197	197	197	197	197	197	197	197	197	197
Wind	2,359	2,395	2,370	2,376	2,376	2,376	2,376	2,376	2,376	2,376
Total	69,134	68,550	68,065	67,683	67,070	66,692	66,502	66,297	65,934	65,450

Probabilistic Assessment Overview

- **General Overview:** SPP oversees the bulk electric grid and wholesale power market as one consolidated BA area on behalf of a diverse group of utilities and transmission companies in 14 states. Firm imports and exports of capacity were modeled to reflect the firm transactions reported for this *2018 LTRA*. Assumptions and the accompanying methodology have been thoroughly vetted through the SPP stakeholder process. No events for loss of load occurred in the Base Case for the ProbA, and loss of load occurred in one of the sensitivity cases.
- **Modeling:** A Monte-Carlo based software called SERVM was used in the 2018 ProbA by randomly selecting load forecast uncertainty errors, derived from historical probability of occurrence, while varying the availability of thermal, hydro, and DR resources. The generating resources modeled in the ProbA reflect the data supplied in this *2018 LTRA*. Existing and projected resources were included in the ProbA along with reported confirmed and unconfirmed retirements. Thermal units follow a two-state sequence for each simulation and utilize unit-specific outage rates based on five years of NERC GADS data. Wind and solar resources were modeled at historical hourly output values based on 2014 weather year:
    - Data from a total of 17 legacy BA areas were used, and SPP modeled a projected 8,760 hourly demand profile for each area to provide load variability and volatility for chronological hours during simulation. The load forecast uncertainty factors for each area varied from zero percent at the 50th percentile to five percent at the 90th percentile above a 50/50 forecasted peak demand. No multipliers were modeled below 50/50 forecast in the simulations to only focus on increases of demand. Each local resource zone was modeled with an import and export limit based on power flow transfer analysis. A base case was modeled along with two sensitivity case simulations that increased the forecasted demand and energy from the original Base Case.
- **Probabilistic vs. Deterministic Assessments:** DR values reported in this *2018 LTRA* were modeled as generating resources available during daily on-peak hours instead of reducing the total internal demand. The dc tie transactions were modeled as resources for the full capacity of the firm transmission service reservations instead of limited to the forecasted amounts of flow across the ties.

Base Case Study

- No loss of load events were indicated for the Base Case study due to a surplus of capacity in the SPP assessment area. Reserve margins are well above 20 percent in both study years, and no major impacts were observed related to resource retirements.
- The 2016 ProbA results for SPP indicated 0.0 EUE and 0.0 Hours/year LOLH for years 2018 and 2020. The 2016 ProbA Base Case results for 2020 were the same for the 2018 Base Case results (i.e., zero loss of load). Also, the ProbA forecast Planning Reserve Margin for the 2020 study year was two percent lower in 2016 ProbA compared to the 2018 Assessment.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	22.7	29.3	25.0
Prospective	15.0	20.7	17.1
Reference	12.0	12.0	12.0
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: The SPP assessment area planning reserve margin requirement for the 2018 summer is 12 percent unless a members capacity mix is comprised of at least 75 percent hydro-based generation; if this is the situation, the planning reserve margin is 9.89 percent. Based on the assessment results, the Anticipated Reserve Margin does not fall below the Reference Margin Level for the SPP assessment area.

Demand: The SPP assessment area forecasts the noncoincident total internal demand to peak at 52,056 MW during the 2018 summer season, which is a decrease of approximately 500 MW from in the previous year's LTRA forecast for the 2018 summer season. The SPP assessment area forecasts the noncoincident annual peak growth, based on member submitted data over the 10-year forecast, at an average annual rate of approximately .07 percent.

Demand-Side Management: The SPP assessment area's energy efficiency and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in energy efficiency and DR across the assessment area. The SPP assessment area forecasts the noncoincident summer peak growth at an average annual rate of one percent.

Distributed Energy Resources: SPP assessment area currently has about 250 MW of installed solar generating facilities. There are approximately 7,800 MW of solar projects in the generator interconnection queue of which 170 MW have effective interconnection agreements. SPP model development, economic studies, and the supply adequacy working groups are currently developing policies and procedures around DERs.

Generation: There are some projected retirements in 2018 that are currently expected to be replaced with renewable resources. The impact to the resource adequacy in the assessment area has been studied in the 2017 LOLE study. The reliability impacts to the transmission system were evaluated and addressed in the *2018 Integrated Transmission Plan Near-Term Assessment*.[67] These retirements consist of 896 MW of coal along with 1,145 MW of natural gas and will be retired during the assessment period. SPP is not expecting any long-term reliability impacts resulting from generating plant retirements.

[67] https://www.spp.org/documents/58359/2018_itpnt_report.pdf

Capacity Transfers: The SPP assessment area coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. Annually, SPP assessment area staff coordinates and agrees on transfers to be modeled between Planning Coordinator footprints. Transfer limits in the SPP LOLE study are limited to the firm contract path only and the full capability of the path. There have been no severe scenarios studied that would limit capacity transfers.

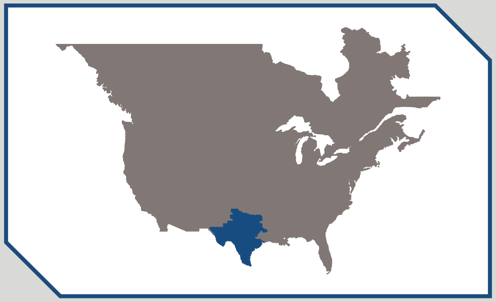
Transmission: The SPP assessment area's board of directors approved the 2017 Integrated Transmission Plan 10-Year Assessment Report[68, 69] and the 2018 Integrated Transmission Planning Near-Term Assessment.[70, 71] Both reports provide details for proposed transmission projects needed to maintain reliability while also providing economic benefit to the end users.

[68] https://www.spp.org/documents/51179/2017_itp10_report_board%20approved_april2017_final.pdf

[69] https://www.spp.org/documents/51179/2017_itp10_report_board%20approved_april2017_final.pdf

[70] https://www.spp.org/documents/51179/2017_itp10_report_board%20approved_april2017_final.pdf

[71] https://www.spp.org/documents/56611/2018_spp_transmission_expansion_plan_report.pdf



Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single Balancing Authority. ERCOT is a summer-peaking Region that covers approximately 200,000 square miles, connects 40,530 miles of transmission lines, and 566 generation units, and serves 23 million customers. The Texas Reliability Entity (Texas RE) is responsible for the RE functions described in the Energy Policy Act of 2005 for the ERCOT Region.

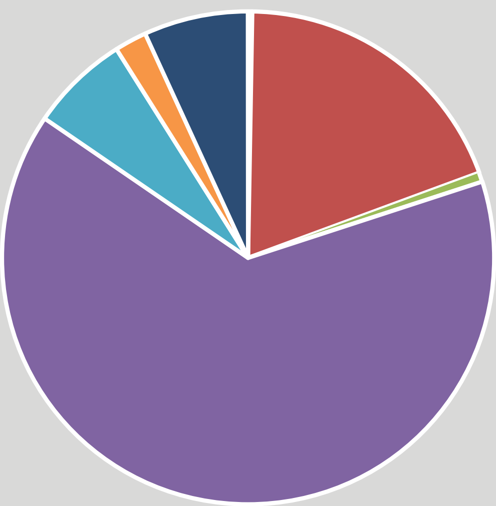
Highlights

- Coal unit retirements and planned generation project delays contribute to lower reserve margins, reflecting the ERCOT market's response to continuing low natural gas and wholesale market prices along with robust growth in low operating cost wind and solar resources.
- To address cyclical generation investment and retirement cycles, the ERCOT market is designed to incentivize increases in supply along with temporary reductions in demand to maintain the reliability of the system.
- The ERCOT Regional Transmission Plan includes the addition or upgrade of almost 3,600 MW of 138 kV and 345 kV transmission circuits by 2025. Significant reliability projects focus on far West Texas, the lower Rio Grande Valley, and coastal areas, all experiencing robust load growth.
- ERCOT continues to implement enhancements to tools and processes to address increasing amounts of renewable generation on the ERCOT grid. Examples in 2018 include procurement of a secondary wind forecasting service for redundancy and the start of a project to add intrahour wind forecasting to better prepare for potential ramps in wind generation that may require deployment of off-line reserves.

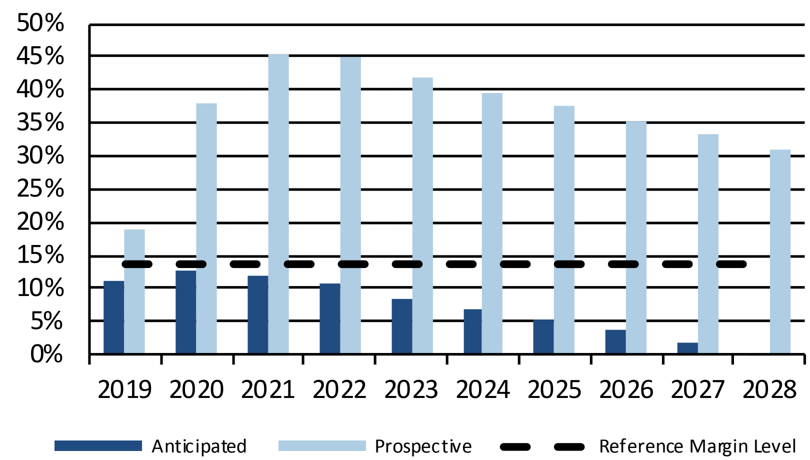
Demand, Resources, and Reserve Margins (MW)

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	74,203	75,879	77,595	79,027	80,431	81,673	82,850	84,179	85,511	86,850
Demand Response	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173
Net Internal Demand	72,030	73,706	75,422	76,854	78,258	79,500	80,677	82,006	83,338	84,677
Additions: Tier 1	2,969	6,022	7,430	8,084	8,084	8,084	8,084	8,084	8,084	8,084
Additions: Tier 2	4,585	17,736	24,786	25,748	25,748	25,797	25,797	25,797	25,797	25,797
Net Firm Capacity Transfers	262	207	57	7	7	7	7	7	7	7
Existing-Certain and Net Firm Transfers	77,104	77,012	76,906	76,916	76,916	76,906	76,906	76,906	76,906	76,906
Anticipated Reserve Margin (%)	11.17	12.66	11.82	10.60	8.62	6.91	5.35	3.64	1.98	0.37
Prospective Reserve Margin (%)	19.06	38.14	45.45	44.90	41.83	39.66	37.63	35.40	33.23	31.12
Reference Margin Level (%)	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75

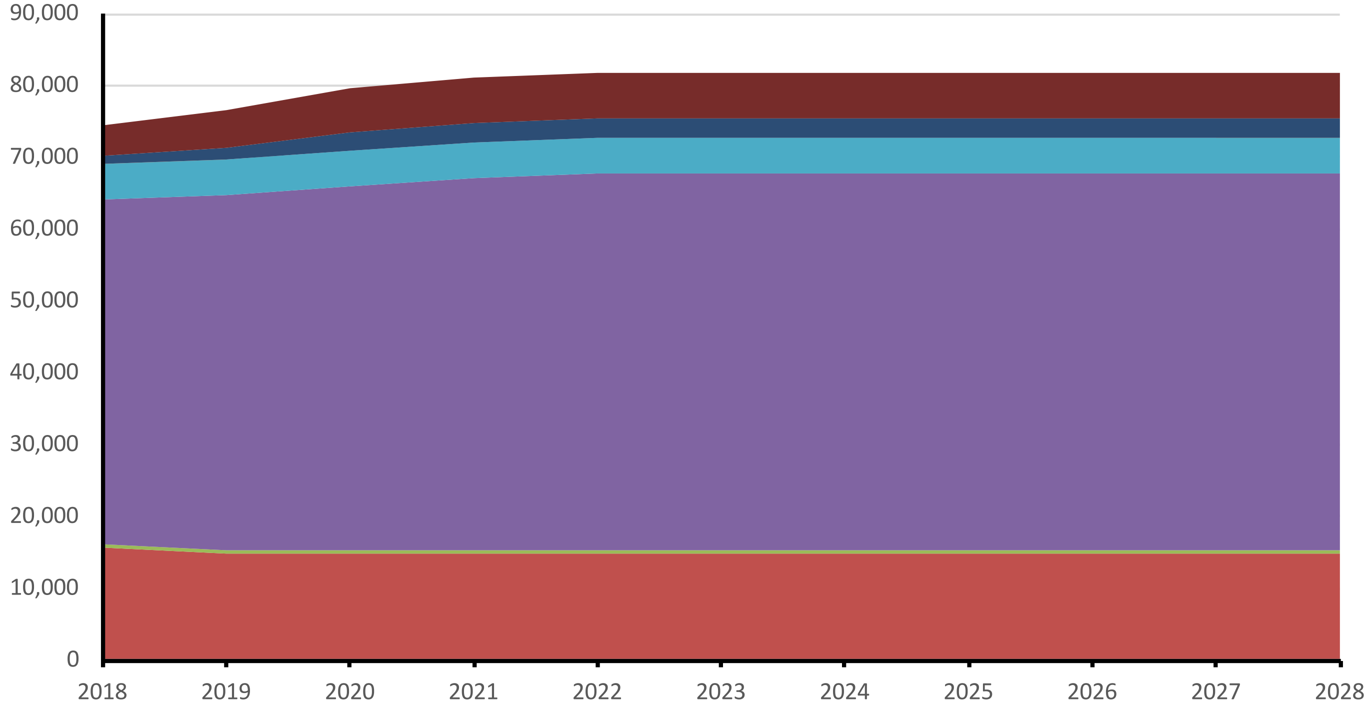
2019 On-Peak Fuel-Mix



Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	202	0%	202	0%
Coal	14,650	19%	14,650	18%
Hydro	466	1%	466	1%
Natural Gas	49,435	65%	52,449	64%
Nuclear	4,960	6%	4,960	6%
Other	0	0%	0	0%
Solar	1,622	2%	2,708	3%
Wind	5,245	7%	6,331	8%
Total	76,580	100%	81,766	100%



Planning Reserve Margins



Texas RE-ERCOT Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	202	202	202	202	202	202	202	202	202	202
Coal	14,650	14,650	14,650	14,650	14,650	14,650	14,650	14,650	14,650	14,650
Hydro	466	466	466	466	466	466	466	466	466	466
Natural Gas	49,435	50,652	51,795	52,449	52,449	52,449	52,449	52,449	52,449	52,449
Nuclear	4,960	4,960	4,960	4,960	4,960	4,960	4,960	4,960	4,960	4,960
Other	0	0	0	0	0	0	0	0	0	0
Solar	1,622	2,558	2,708	2,708	2,708	2,708	2,708	2,708	2,708	2,708
Wind	5,245	6,143	6,331	6,331	6,331	6,331	6,331	6,331	6,331	6,331
Grand Total	76,580	79,631	81,112	81,766	81,766	81,766	81,766	81,766	81,766	81,766

Probabilistic Assessment Overview

- **General Overview:** Projected reserve margins for ERCOT have decreased since the 2016 ProbA, leading to an increased possibility of reliability issues for the study years. The 2020 projected ProbA forecast reserve margin is 12.9 percent. The 2022 projected reserve margin is 10.8 percent.
- **Modeling:** This study used Astrapé Consulting's probabilistic resource adequacy assessment model, SERVM, which simulates chronological hourly unit commitment and economic dispatch. ERCOT was modeled as a single zone connected to SPP and Mexico through dc ties. SERVM captures the uncertainty of weather, economic growth, unit availability, and external assistance from neighboring regions as stochastic variables:
  - The simulations used 15 synthetic load, wind, solar, and hydro profiles, based on historical years 2002–2016, to represent expected conditions in the study years if historical weather conditions were to take place again. ERCOT applied five load forecast uncertainty multipliers to each synthetic weather year. The multipliers, which ranged from -4 percent to +4 percent, capture economic load growth uncertainty.
  - Thermal generator availability was based on GADS data for the past three years submitted by generation entities. SERVM can simulate both full and partial outage using a multi-state Monte Carlo modeling approach.
  - Wind and solar were modeled as capacity resources with hourly profiles that are weather-correlated with the load shapes. The peak capacity contributions were 14 percent for non-coastal wind, 59 percent for coastal wind, and 75 percent for solar.
  - Dispatch heuristics for hydro resources were developed from six years of hourly data from ERCOT, applied to 15 years of monthly data from FERC 923, and modeled with different parameters each month, including monthly total energy output, daily maximum and minimum outputs, and monthly maximum output.
- **Probabilistic vs. Deterministic Assessments:** No changes.

Base Case Study

- The Base Case study results in a number of reliability events during the summer months in the synthetic years with extremely hot temperatures. In addition to firm load shed events, other reliability events occur within the simulation with higher frequency than seen in the 2016 ProbA study. These events include reductions in operating reserves and dispatching of emergency resources. The events occurred predominantly in August, which accounted for 88.0 percent of the LOLH and 92.1 percent of the EUE in 2020. The Anticipated Reserve Margin is lower than the ProbA forecast Planning Reserve Margin due to modeling treatment differences on importing and exporting resources.
- **Results Trending:** Compared to the results from the 2016 ProbA, LOLH increased from 0.000004 to 0.50 for the first study year. The results are driven by a decrease in the Anticipated Reserve Margin. ERCOT has seen over 4 GW of conventional plant retirements and 2.1 GW of planned project deferrals in the past two years.

Summary of Results		
Reserve Margin		
	Base Case	
	2020	**2022**
Anticipated	12.7	10.6
Prospective	38.1	44.9
Reference	13.8	13.8
ProbA Forecast Planning	12.9	10.8
ProbA Forecast Operable	6.2	4.6
Annual Probabilistic Indices		
	Base Case	
	2020	**2022**
EUE (MWh)	598.90	1088.72
EUE (ppm)	1.53	2.64
LOLH (hours/year)	0.50	0.87

Planning Reserve Margins: The Anticipated Reserve Margin falls below the Reference Margin Level of 13.75 percent starting in Summer 2018 and remains below for the duration of the LTRA forecast period. The drop in the reserve margin is mainly due to the retirement of over 4,000 MW of coal and natural gas resources in late 2017 and early 2018 as well as reported delays in planned resource capacity by project developers. To respond to such cyclical resource investment and retirement trends, the ERCOT market is designed to incentivize increases in supply along with temporary reductions in demand to maintain the reliability of the system. For example, there are programs operated by ERCOT, retail electric providers, and distribution utilities that compensate customers for reducing their demand or operating their own generation in response to market prices and anticipated capacity scarcity conditions. ERCOT also has operational tools available to maintain system reliability. Examples include releasing load resource capacity qualified to provide responsive reserve ancillary service, requesting emergency power across the dc ties to neighboring grids, and requesting emergency support from available switchable generators currently serving non-ERCOT grids.

Demand: Based on preliminary data, the TRE-ERCOT Region set an all-time peak demand record of 73,259 MW on July 19, 2018, as compared to the forecasted amount of 72,756 MW used for the *2018 Summer Reliability Assessment*. According to ERCOT's latest long-term peak demand forecast, annual peak demand is expected to increase by a compounded annual rate of 1.8 percent from 2018 through 2028. This forecast is higher than the forecast used for the *2017 LTRA*. The increase is primarily due to a projected increase in economic growth driven by activity in the oil and natural gas exploration sector, petrochemical plant expansion along the Gulf Coast, and an overall stronger employment outlook over the forecast horizon. In addition, Lubbock Power & Light has received approval to have some of its load (almost 500 MW) moved into ERCOT beginning in the summer of 2021. ERCOT's long-term load forecast is based on a set of models describing the hourly load in eight weather zones as a function of the number of premises in various customer classes (residential, business, and industrial), economic variables weather variables (e.g., heating and cooling degree days, temperature, cloud cover, wind speed, dew point) and calendar variables (day of week, holiday).

Demand-Side Management: The DSM forecasted for 2018 comes from dispatchable resources in the form of noncontrollable load resources that provide responsive reserve service[72] (1,119 MW), emergency response service (793 MW, based on actual contracted capacity), and load management programs administered by transmission/distribution service providers (282 MW).[73] These forecasts reflect a gross-up of two percent to reflect avoided transmission line losses. For 2019 and beyond, ERCOT assumes that the load resource capacity amounts remain constant. The ERS capacity forecast for 2019 and beyond is 772 MW. This figure is based on a three-year historical compounded program growth rate along with the two percent gross-up. ERCOT develops its own energy efficiency forecast using annual reports of verified incremental peak load energy efficiency impacts from the Public Utility Commission of Texas and Texas State Energy Conservation Office.[74]

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[72] This value reflects a 95 percent confidence level based on historical data for the 3:00 p.m. through 6:00 p.m. time period during the months of June through September over the last three years. The hourly participation is capped at 60 percent of the system-wide obligation for responsive reserve service, which can range from 2,300 to 3,019 MW.

[73] Includes a two percent gross-up adjustment for avoided transmission line losses.

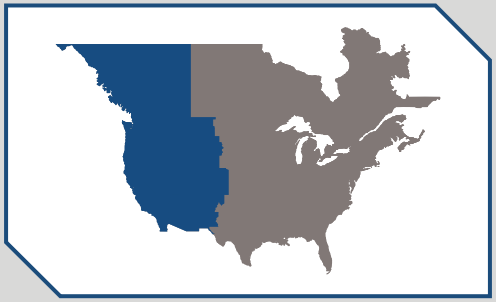
[74] Verified impacts are derived through an Evaluation, Measurement & Verification (EM&V) framework approved by the Public Utility Commission of Texas (PUCT). The statutory EM&V framework is outlined in the Commission's Substantive Rule 25.181, available at the following: https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.181/25.181.pdf, subsection (q). The verified savings are estimated by a third-party contractor selected by the PUCT. Information on the EM&V program, including the associated technical reference manual, is available at http://www.texasefficiency.com/index.php/emv. Growth trends in the annual verified MW amounts are used to develop the forecast.

Distributed Energy Resources: The installed solar DER capacity forecasted for the five-year horizon (ending 2023) is approximately 1,500 MW, reflecting a growth rate significantly higher than assumed for last year's LTRA. Based on current capacity growth and market trends, ERCOT believes that DER does not pose near-term reliability issues for the grid. Nevertheless, it intends to prepare for a future scenario in which a larger share of the regional generation mix may come from the distribution system.[75] An important ERCOT initiative involves mapping all existing registered DERs (>1 MW and importing into the grid) to the Common Information Model at their load points. Once in the Network Operations Model, the DER locations will be known to ERCOT operators, improving situational awareness and allowing for incorporation into power flow, state estimator, and load forecast programs. A Nodal Protocol Revision Request for implementing the DER mapping was submitted by ERCOT staff in February 2018 and is awaiting board of directors approval.

Generation: Since the 2017 LTRA, about 3,400 MW of utility-scale nameplate capacity has been added to the TRE-ERCOT Region. The percentage contributions by fuel type are wind at 56 percent, natural gas at 23 percent, and solar at 21 percent. A total of 4,540 MW of summer-rated capacity have been retired, primarily due to economic reasons. The breakdown by fuel type is 3,673 MW coal and 867 MW natural gas. ERCOT continues to implement enhancements to tools and processes to address increasing amounts of renewable generation on the ERCOT grid. One such enhancement completed in 2018 was to procure a secondary wind forecasting service to add redundancy to the forecasting process. Moreover, both wind forecast systems are now able to better estimate the impact of extreme weather conditions, such as icing and high speed wind turbine shutdowns. ERCOT is also adding intrahour wind forecasting to better prepare for potential ramps in wind generation that may require deployment of offline reserves.

To estimate the amount of renewable capacity available to meet seasonal peak loads, ERCOT relies on average historical availability during the 20 highest peak load hours for each season over a span of years specific to the renewable generation type. For wind, the historical period for averaging was nine years for noncoastal resources (2009–2017) and eight years for coastal resources (2010–2017). For solar and hydro, the historical period is three years (2015–2017).

[75] ERCOT published a whitepaper, "*Distributed Energy Resources: Reliability Impacts and Recommended Changes,*" March 22, 2017, outlining the challenges and potential impacts of DERs, available at the following: http://www.ercot.com/content/wcm/lists/121384/DERs_Reliability_Impacts_FINAL.pdf.

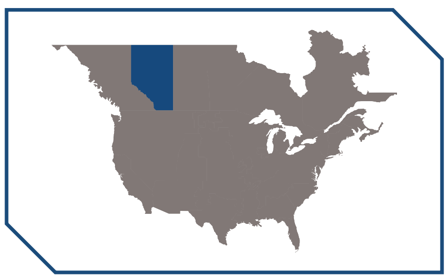


WECC

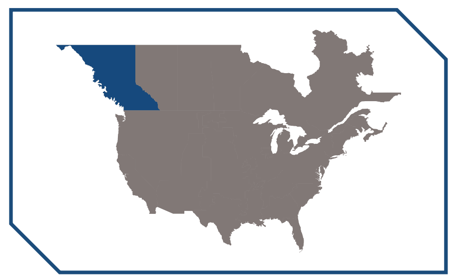
The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting Bulk Electric System reliability in the Western Interconnection. WECC's 329 members, which include 38 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and approximately 82.2 million people, it is geographically the largest and most diverse of the NERC Regional Entities. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western states in between. The WECC assessment area is divided into five subregions: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), and the Northwest Power Pool (NWPP), which is further divided into the NW-Canada and NW-US areas. These subregional divisions are used for this assessment, as they are structured around reserve sharing groups that have similar annual demand patterns and similar operating practices.

Highlights

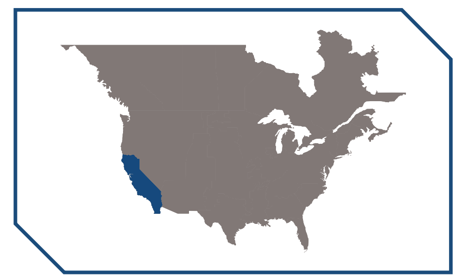
- The Western Interconnection and all the individual subregions are expected to have sufficient generation capacity to exceed the Reference Margin Level during the assessment period.
- The Los Angeles Basin in Southern California continues to be an area of short-term concern due to the reduced availability of the Aliso Canyon natural gas storage facility. WECC continues to study and work with SoCal Gas and California ISO to assess the potential impacts to reliability for the Western Interconnection associated with the limited availability of Aliso Canyon.
- The 2018 summer season has seen increased system stress due to higher-than-average temperatures and a continuing trend of a high number of wildfires; 8,717 fires as of August 2018 compared to 9,000 for all of 2017 (https://www.ncdc.noaa.gov/societal-impacts/wildfires/month/7?params[]=fires&params[]=acres&end_date=2018). The increased temperatures and wildfires are impacting most states and provinces in the Western Interconnection, but the largest incidents are located in California, Arizona, Utah, Idaho, Oregon, and British Columbia.
- WECC has completed a study of the impacts to reliability associated with the interdependence of the natural gas and electric systems. The key findings include the Western Interconnections facing increasing volumetric and flexibility constraints, and disruptions in the natural gas system could potentially translate quickly to loss of load in the Desert Southwest and Southern California regions. The complete study, including recommendations for improvement, can be found here: (https://www.wecc.biz/Administrative/WECC20Gas-Electric20Study20Public20Report.pdf).
- Distributed energy resources continue to be well understood at the LSE level and ongoing analyses continue to be performed regarding increases in penetration, particularly in California. The California ISO has begun an initiative to try to properly account for behind-the-meter generation on their system. This initiative proposes to establish a standard reporting practice for excess behind-the-meter production, determine the appropriate practice for representation of excess BTM production in the ISO market process, and explore the potential impacts of the reporting of gross load and excess BTM on scheduling coordinators that submit meter data to the ISO. More information on this initiative can be found here: (http://www.caiso.com/Documents/IssuePaper-ExcessBehindtheMeterProduction.pdf).
- Three 55 MW oil-fired units in CAISO (WECC-CAMX assessment area) will be needed through 2018 to ensure reliability. CAISO's board of governors extended an RMR contract in September 2017 for the three units located near Oakland, CA.



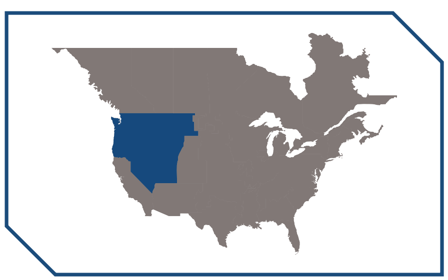
WECC-AB



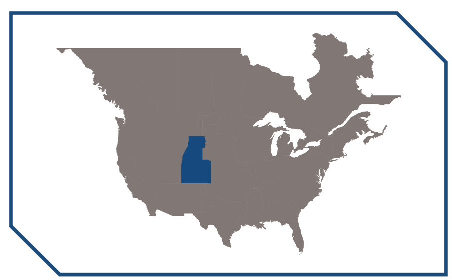
WECC-BC



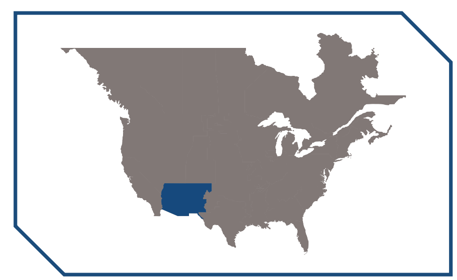
WECC-CAMX



WECC-NWPP-US

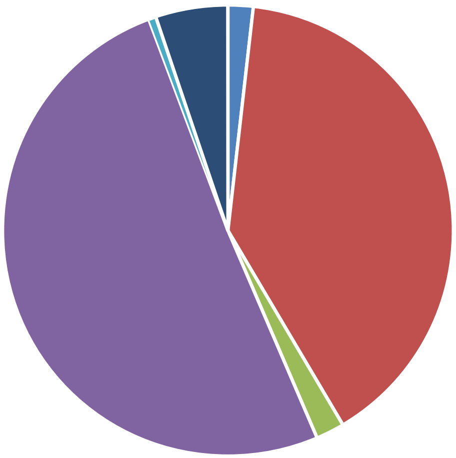


WECC-RMRG



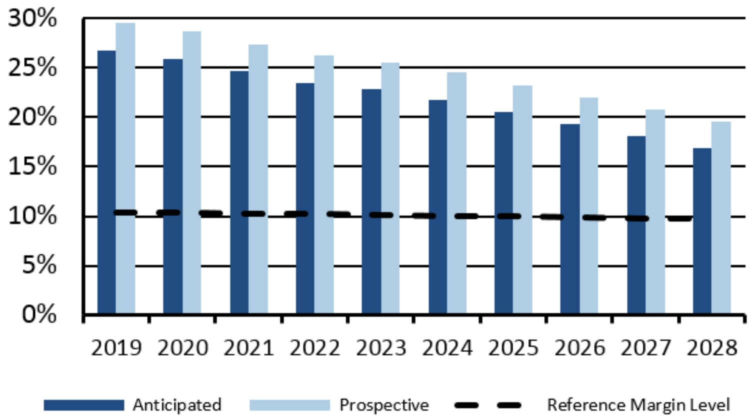
WECC-SRSG

Demand, Resources, and Reserve Margins (MW)										
Quantity	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Total Internal Demand	11,939	12,018	12,144	12,260	12,321	12,428	12,557	12,678	12,814	12,945
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,939	12,018	12,144	12,260	12,321	12,428	12,557	12,678	12,814	12,945
Additions: Tier 1	43	43	43	43	43	43	43	43	43	43
Additions: Tier 2	338	338	338	338	338	338	338	338	338	338
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	15,091	15,091	15,091	15,091	15,091	15,091	15,091	15,091	15,091	15,091
Anticipated Reserve Margin (%)	26.76	25.93	24.62	23.44	22.83	21.77	20.52	19.37	18.10	16.91
Prospective Reserve Margin (%)	29.60	28.74	27.41	26.20	25.58	24.50	23.22	22.04	20.74	19.52
Reference Margin Level (%)	10.42	10.36	10.28	10.21	10.14	10.05	9.95	9.88	9.80	9.73

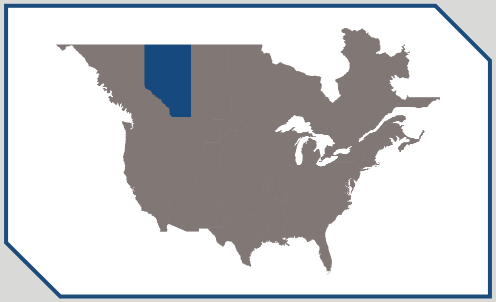


2019 On-Peak Fuel-Mix

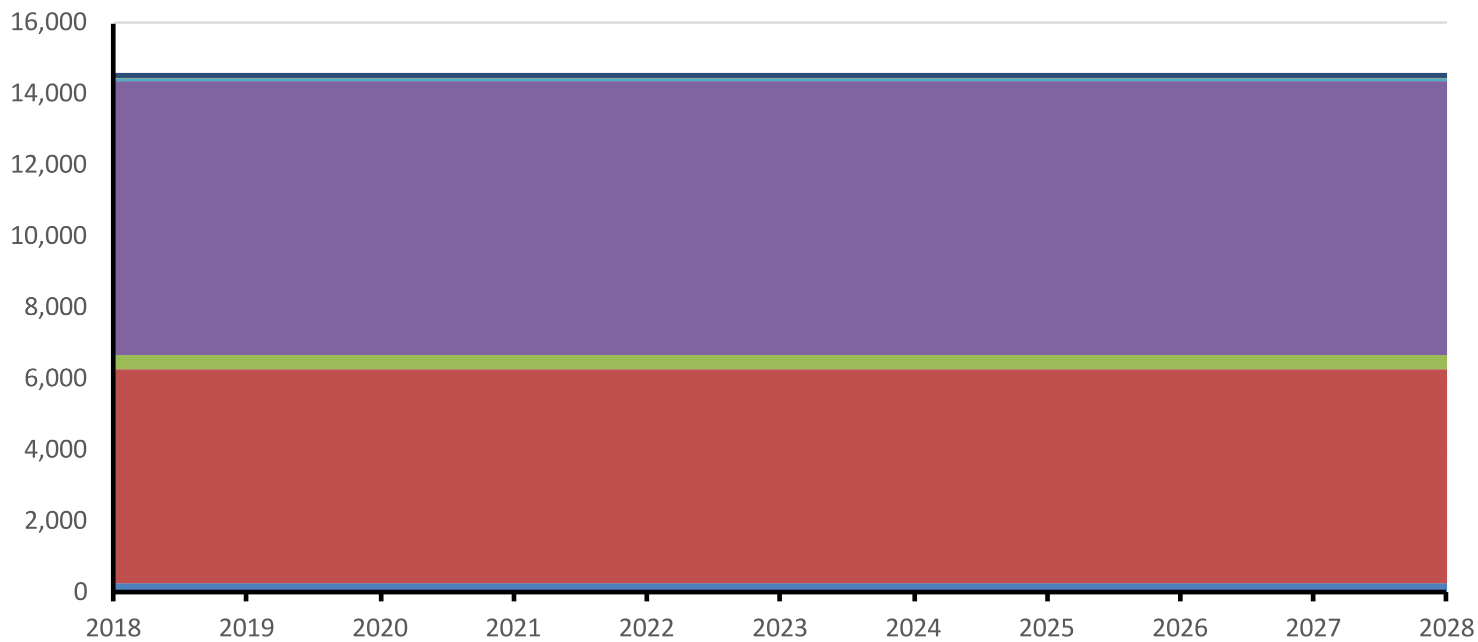
Generation Type	Winter 2019–2020 MW
Biomass	273
Coal	6,275
Hydro	415
Natural Gas	7,533
Other	70
Solar	0
Wind	663



WECC-AB Planning Reserve Margins



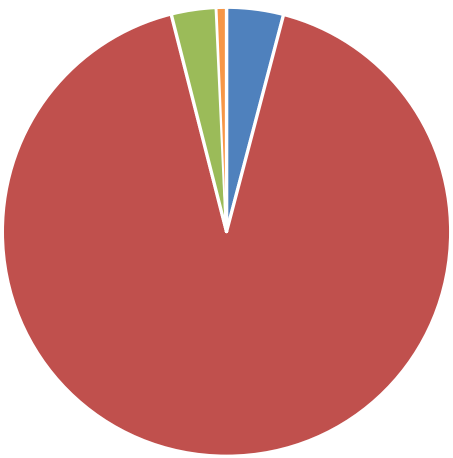
WECC-AB



WECC-AB Fuel Composition

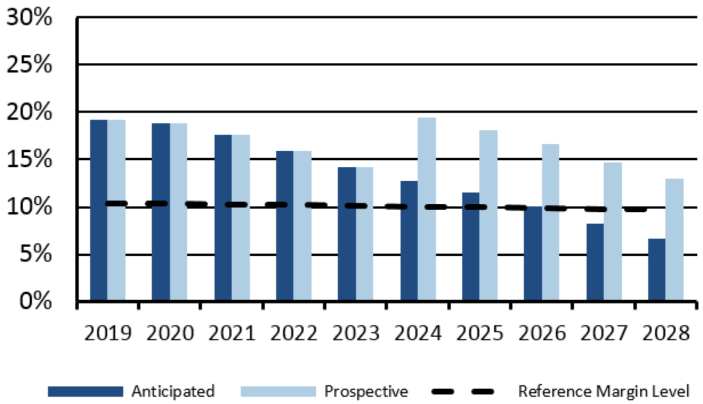
Gen Type	2019–2020	2020–2021	2021–2022	2022–2023	2023–2024	2024–2025	2025–2026	2026–2027	2027–2028	2028–2029
Biomass	272	272	272	272	272	272	272	272	272	272
Coal	6,007	6,007	6,007	6,007	6,007	6,007	6,007	6,007	6,007	6,007
Hydro	409	409	409	409	409	409	409	409	409	409
Natural Gas	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682
Other	78	78	78	78	78	78	78	78	78	78
Solar	14	14	14	14	14	14	14	14	14	14
Wind	142	142	142	142	142	142	142	142	142	142
Total	14,603	14,603	14,603	14,603	14,603	14,603	14,603	14,603	14,603	14,603

Demand, Resources, and Reserve Margins (MW)										
Quantity	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Total Internal Demand	11,468	11,616	11,797	11,972	12,186	12,346	12,516	12,682	12,894	13,088
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,468	11,616	11,797	11,972	12,186	12,346	12,516	12,682	12,894	13,088
Additions: Tier 1	498	622	704	704	745	745	786	786	786	786
Additions: Tier 2	0	0	0	0	0	825	825	825	825	825
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	13,175	13,175	13,175	13,175	13,175	13,175	13,175	13,174	13,174	13,174
Anticipated Reserve Margin (%)	19.22	18.77	17.65	15.93	14.23	12.75	11.55	10.08	8.27	6.67
Prospective Reserve Margin (%)	19.22	18.77	17.65	15.93	14.23	19.43	18.14	16.59	14.67	12.97
Reference Margin Level (%)	10.42	10.36	10.28	10.21	10.14	10.05	9.95	9.88	9.80	9.73

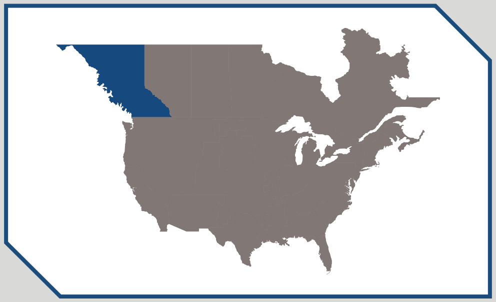


2019 On-Peak Fuel-Mix

Generation Type	Winter 2019–2020 MW
Biomass	399
Hydro	10,580
Natural Gas	390
Other	5
Solar	1
Wind	150



WECC-BC Planning Reserve Margins



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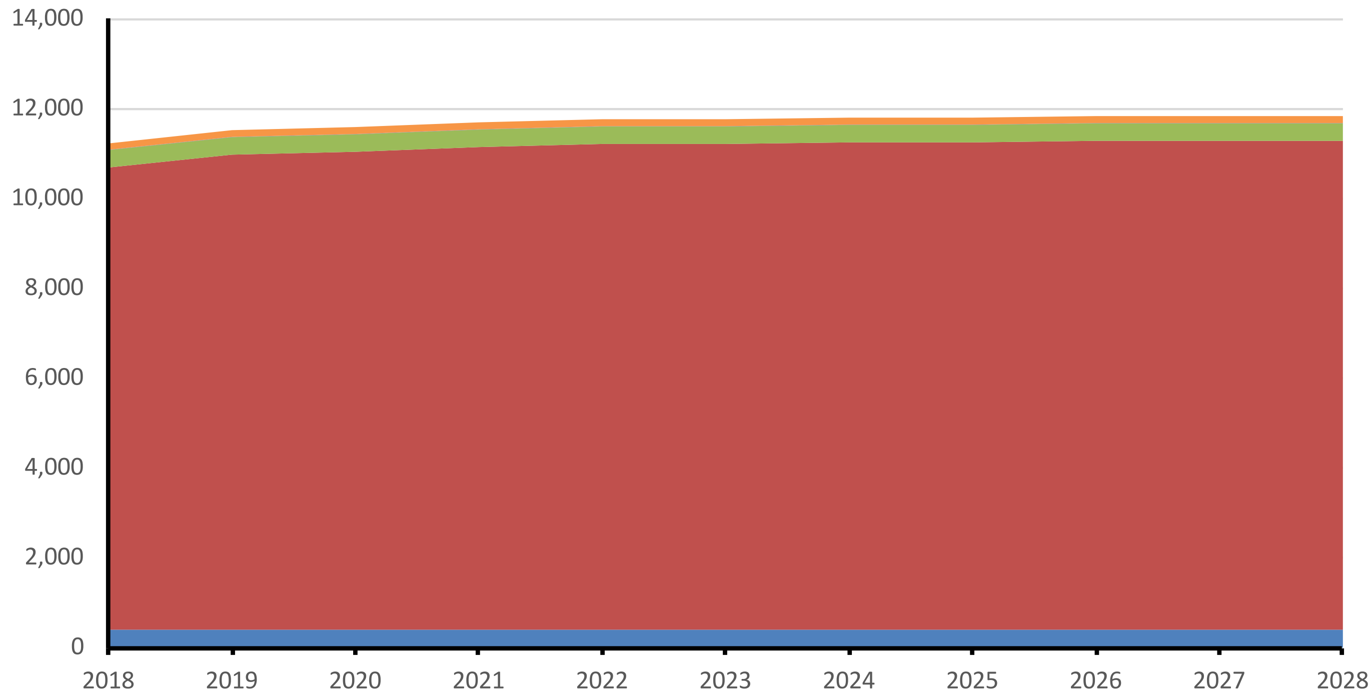
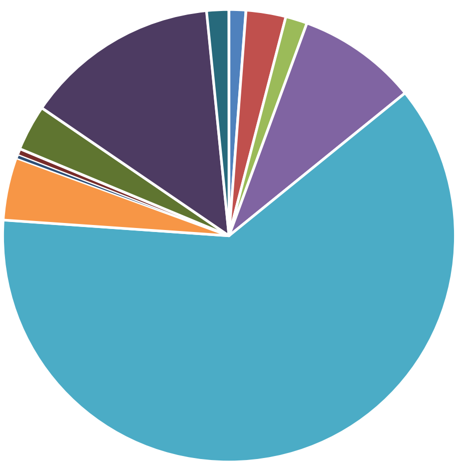


WECC-BC Fuel Composition

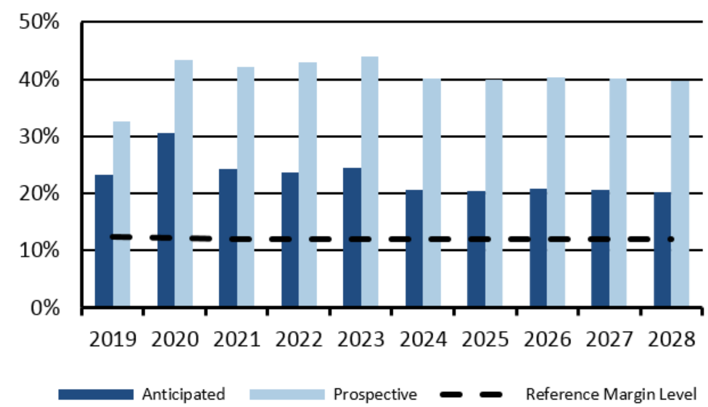
Gen Type	2019–2020	2020–2021	2021–2022	2022–2023	2023–2024	2024–2025	2025–2026	2026–2027	2027–2028	2028–2029
Biomass	399	399	399	399	399	399	399	399	399	399
Hydro	10,580	10,644	10,749	10,818	10,818	10,853	10,853	10,888	10,888	10,888
Natural Gas	390	390	390	390	390	390	390	390	390	390
Other	5	5	5	5	5	5	5	5	5	5
Solar	1	1	1	1	1	1	1	1	1	1
Wind	150	155	155	155	155	155	155	155	155	155
Total	11,525	11,594	11,699	11,768	11,768	11,803	11,803	11,838	11,838	11,838

Demand, Resources, and Reserve Margins (MW)										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	55,109	51,091	51,219	51,476	51,127	52,373	52,510	52,306	52,397	52,571
Demand Response	970	959	944	926	926	926	926	926	926	926
Net Internal Demand	54,139	50,132	50,275	50,550	50,201	51,447	51,584	51,380	51,471	51,645
Additions: Tier 1	1,799	1,861	1,921	1,943	1,953	1,965	1,977	1,990	2,002	2,010
Additions: Tier 2	4,998	6,382	8,984	9,733	9,733	10,044	10,044	10,044	10,044	10,044
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	64,936	63,586	60,550	60,550	60,550	60,106	60,106	60,106	60,106	60,106
Anticipated Reserve Margin (%)	23.27	30.55	24.26	23.63	24.51	20.65	20.35	20.86	20.67	20.27
Prospective Reserve Margin (%)	32.50	43.28	42.13	42.88	43.89	40.17	39.82	40.40	40.18	39.72
Reference Margin Level (%)	12.35	12.29	12.10	12.05	12.02	12.05	11.99	11.99	12.02	12.04



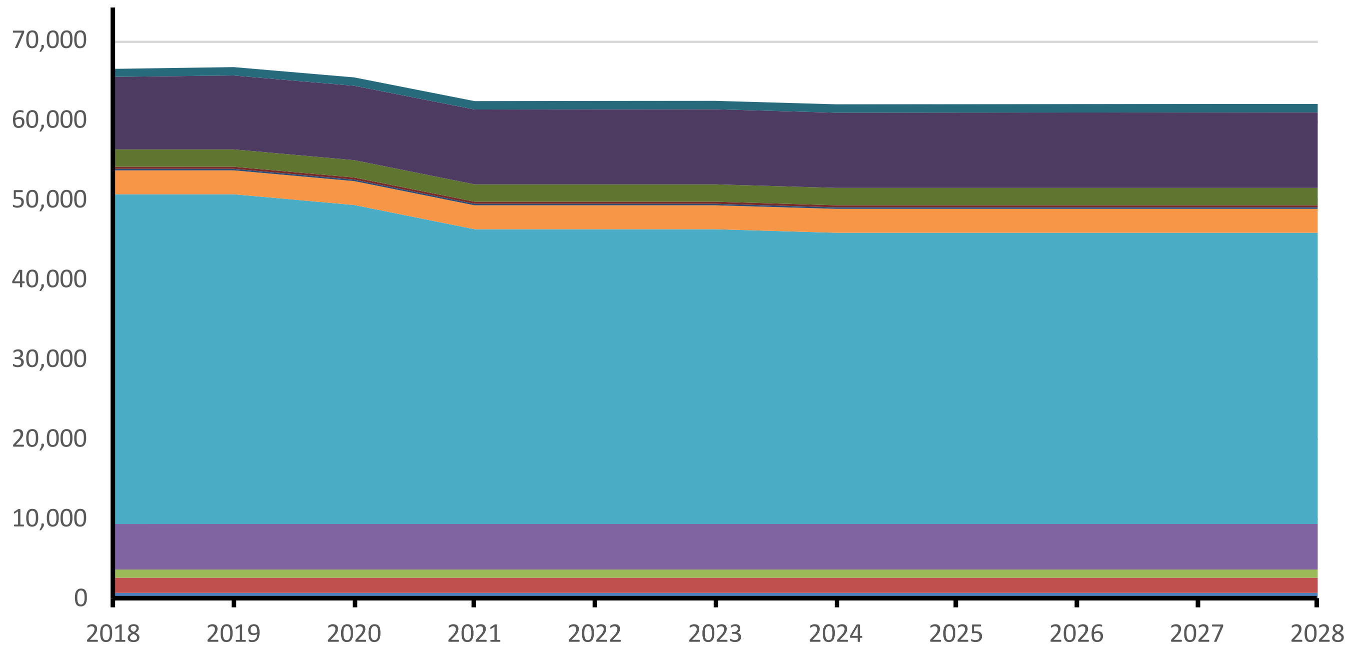
2019 On-Peak Fuel-Mix

Generation Type	Summer 2019 MW
Biomass	803
Coal	1,896
Geothermal	1,030
Hydro	5,709
Natural Gas	41,352
Nuclear	3,000
Other	190
Petroleum	261
Pumped Storage	2,177
Solar	9,265
Wind	1,053



WECC-CAMX Planning Reserve Margins

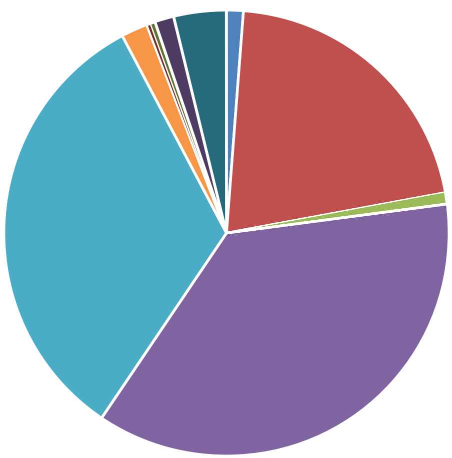
WECC-CAMX



WECC-CAMX Fuel Composition

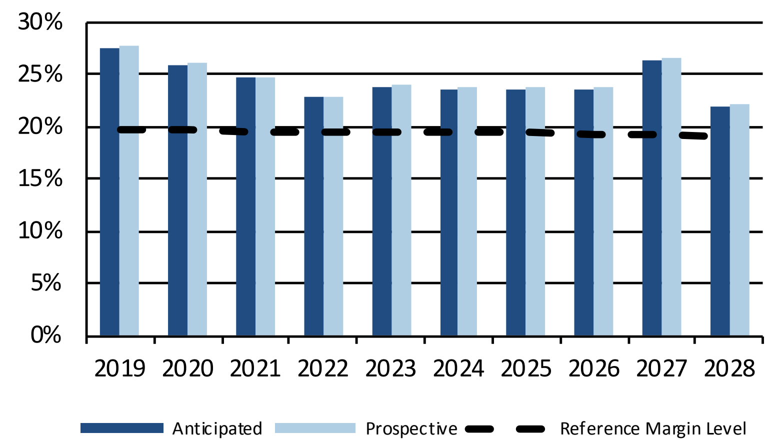
Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	803	803	803	803	803	803	803	803	803	803
Coal	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896
Geothermal	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030
Hydro	5,709	5,710	5,710	5,710	5,710	5,710	5,710	5,710	5,710	5,710
Natural Gas	41,352	40,001	36,966	36,966	36,966	36,522	36,522	36,522	36,522	36,522
Nuclear	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Other	190	190	190	190	190	190	190	190	190	190
Petroleum	261	261	261	261	261	261	261	261	261	261
Pumped Storage	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Solar	9,265	9,325	9,386	9,407	9,418	9,430	9,441	9,454	9,466	9,473
Wind	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,054
Grand Total	66,735	65,447	62,472	62,493	62,504	62,072	62,083	62,096	62,108	62,116

Demand, Resources, and Reserve Margins										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	47,643	50,003	50,434	50,625	51,085	51,405	51,717	51,999	52,364	52,628
Demand Response	918	928	939	943	944	949	950	953	955	956
Net Internal Demand	46,725	49,075	49,495	49,682	50,141	50,456	50,767	51,046	51,409	51,672
Additions: Tier 1	53	146	146	236	236	236	236	236	236	236
Additions: Tier 2	94	94	94	94	94	94	94	94	94	94
Net Firm Capacity Transfers	0	2,100	2,620	2,200	3,300	3,600	4,200	4,900	7,000	5,800
Existing-Certain and Net Firm Transfers	59,552	61,652	61,537	60,750	61,850	62,150	62,538	62,898	64,776	62,822
Anticipated Reserve Margin (%)	27.57	25.92	24.62	22.75	23.82	23.64	23.65	23.68	26.46	22.03
Prospective Reserve Margin (%)	27.77	26.12	24.81	22.94	24.01	23.83	23.83	23.86	26.64	22.22
Reference Margin Level (%)	19.72	19.68	19.53	19.60	19.56	19.49	19.39	19.35	19.27	19.11

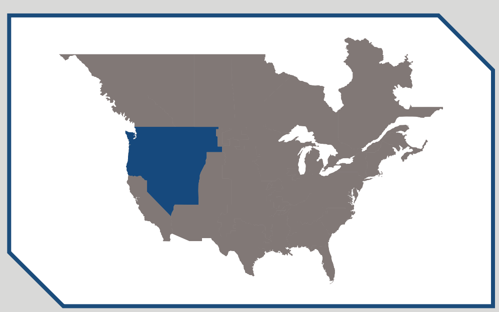


2019 On-Peak Fuel-Mix

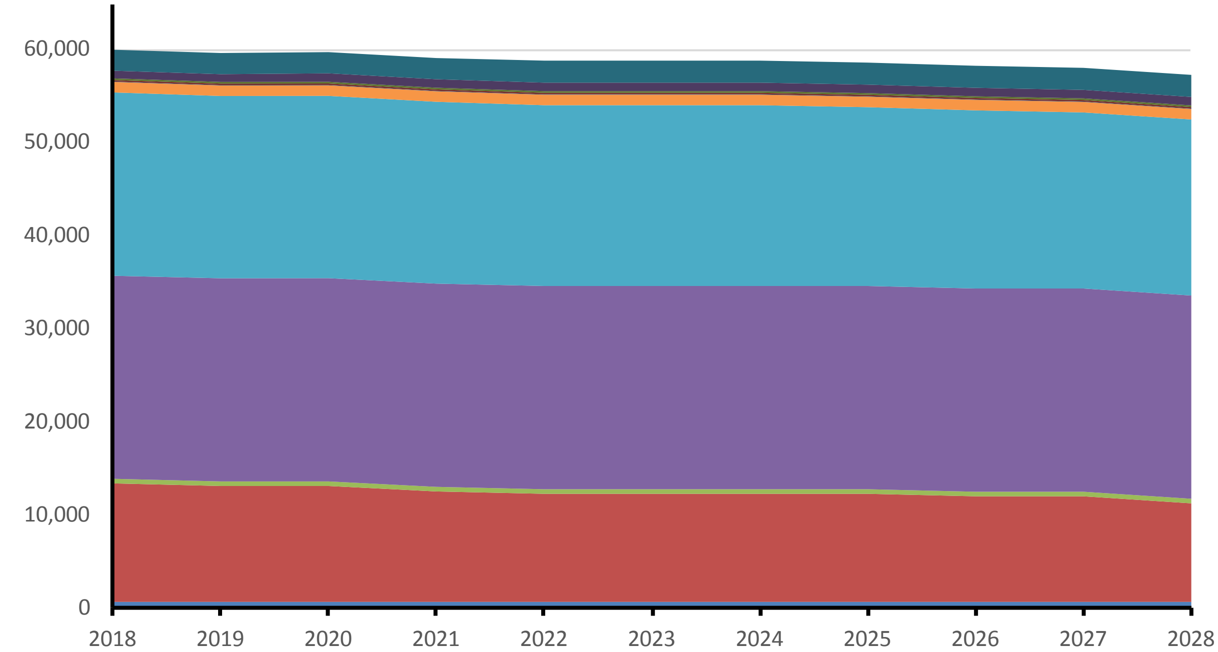
Generation Type	Summer 2019 MW
Biomass	733
Coal	12,431
Geothermal	492
Hydro	21,786
Natural Gas	19,553
Nuclear	1130
Other	44
Petroleum	152
Pumped Storage	182
Solar	830
Wind	2273



WECC NWPP-US Planning Reserve Margins



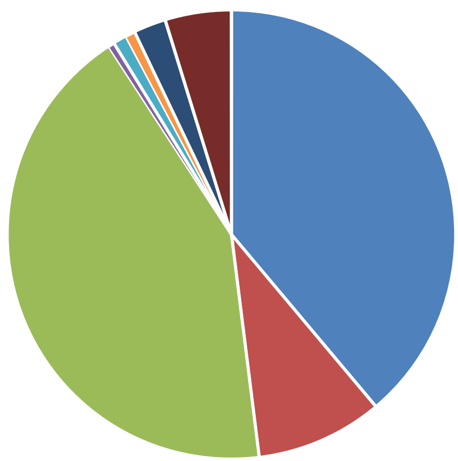
WECC-NWPP-US



WECC-NWPP-US Fuel Composition

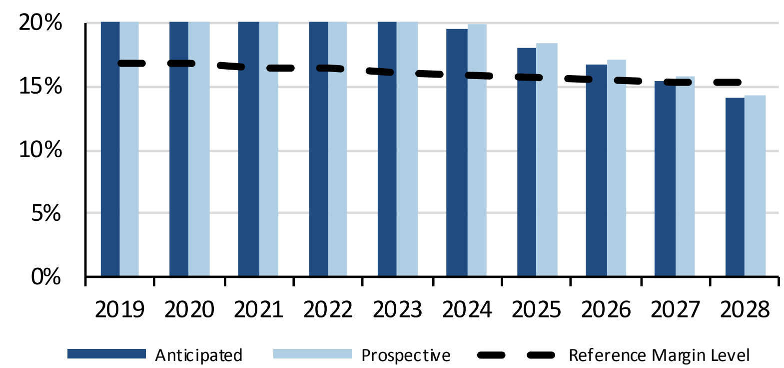
Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	733	733	733	733	733	733	733	733	733	733
Coal	12,431	12,431	11,846	11,592	11,592	11,592	11,592	11,324	11,324	10,570
Geothermal	492	492	492	492	492	492	492	492	492	492
Hydro	21,786	21,797	21,797	21,797	21,797	21,797	21,797	21,797	21,797	21,797
Natural Gas	19,553	19,553	19,503	19,390	19,390	19,390	19,178	19,106	18,884	18,884
Nuclear	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130
Other	44	44	44	44	44	44	44	44	44	44
Petroleum	152	152	152	152	152	152	152	152	152	152
Pumped Storage	182	182	182	182	182	182	182	182	182	182
Solar	830	911	911	911	911	911	911	911	911	911
Wind	2,273	2,273	2,273	2,363	2,363	2,363	2,363	2,363	2,363	2,363
Grand Total	59,605	59,698	59,063	58,786	58,786	58,786	58,574	58,234	58,012	57,258

Demand, Resources, and Reserve Margins										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	12,182	12,925	13,094	13,239	13,489	13,655	13,835	13,980	14,129	14,308
Demand Response	295	288	288	287	287	286	286	285	285	284
Net Internal Demand	11,888	12,637	12,806	12,952	13,202	13,369	13,549	13,695	13,844	14,024
Additions: Tier 1	184	281	281	281	281	281	281	281	281	281
Additions: Tier 2	0	0	0	0	44	44	44	44	44	44
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	15,711	15,711	15,711	15,711	15,711	15,711	15,711	15,711	15,711	15,711
Anticipated Reserve Margin (%)	33.72	26.56	24.89	23.48	21.14	19.63	18.04	16.78	15.52	14.04
Prospective Reserve Margin (%)	33.72	26.56	24.89	23.48	21.47	19.95	18.36	17.10	15.84	14.35
Reference Margin Level (%)	16.83	16.76	16.48	16.37	16.07	15.94	15.73	15.58	15.40	15.25

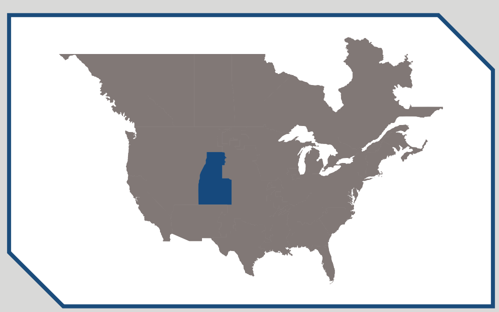


2019 On-Peak Fuel-Mix

Generation Type	Summer 2019 MW
Biomass	3
Coal	6,178
Hydro	1,454
Natural Gas	6,798
Other	70
Petroleum	157
Pumped Storage	108
Solar	370
Wind	759



WECC-RMRG Planning Reserve Margins

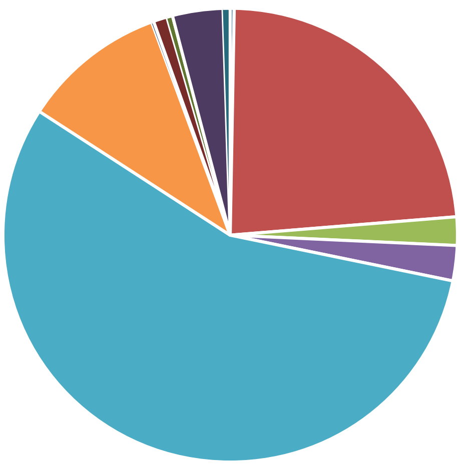


WECC-RMRG

WECC-RMRG Fuel Composition

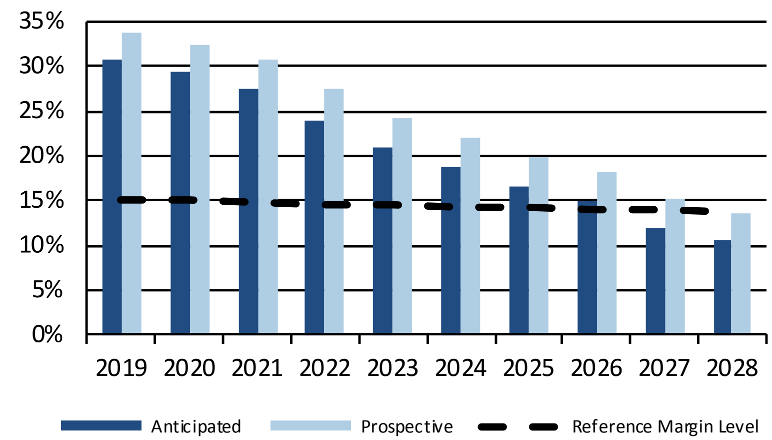
Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	3	3	3	3	3	3	3	3	3	3
Coal	6,178	6,178	6,178	6,178	6,178	6,178	6,178	6,178	6,178	6,178
Hydro	1,454	1,454	1,454	1,454	1,454	1,454	1,454	1,454	1,454	1,454
Natural Gas	6,798	6,798	6,798	6,798	6,798	6,798	6,798	6,798	6,798	6,798
Other	70	70	70	70	70	70	70	70	70	70
Petroleum	157	157	157	157	157	157	157	157	157	157
Pumped Storage	108	108	108	108	108	108	108	108	108	108
Solar	370	466	466	466	466	466	466	466	466	466
Wind	759	759	759	759	759	759	759	759	759	759
Total	15,896	15,993	15,993	15,993	15,993	15,993	15,993	15,993	15,993	15,993

Demand, Resources, and Reserve Margins (MW)										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	24,286	24,484	24,854	25,408	25,898	26,344	26,836	27,207	27,659	28,014
Demand Response	186	186	186	186	186	186	186	186	186	186
Net Internal Demand	24,100	24,298	24,668	25,222	25,712	26,158	26,650	27,021	27,473	27,828
Additions: Tier 1	1,079	1,079	1,079	1,079	1,079	1,079	1,079	1,079	1,079	1,079
Additions: Tier 2	681	722	842	864	864	864	864	864	864	864
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	30,445	30,364	30,364	30,203	30,007	30,007	30,007	30,007	29,683	29,683
Anticipated Reserve Margin (%)	30.80	29.40	27.46	24.03	20.90	18.84	16.64	15.04	11.97	10.54
Prospective Reserve Margin (%)	33.63	32.37	30.87	27.45	24.26	22.14	19.88	18.24	15.11	13.64
Reference Margin Level (%)	15.10	15.11	14.86	14.63	14.47	14.33	14.17	14.03	13.92	13.82

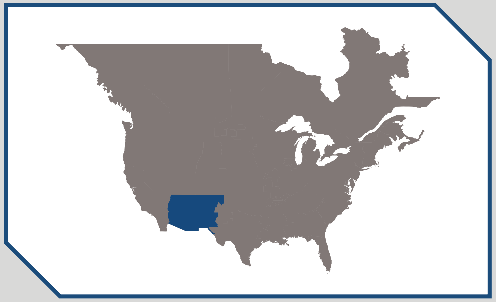


2019 On-Peak Fuel-Mix

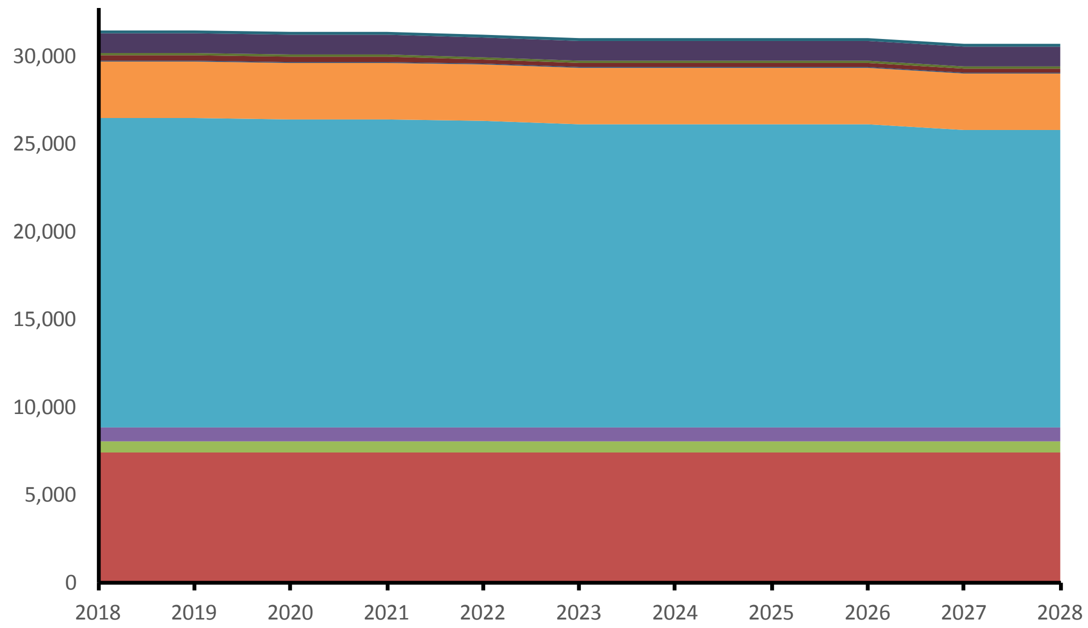
Generation Type	Summer 2019 MW
Biomass	89
Coal	7,385
Geothermal	634
Hydro	794
Natural Gas	17,630
Nuclear	3,217
Other	51
Petroleum	307
Pumped Storage	128
Solar	1,125
Wind	162



WECC-SRSG Planning Reserve Margins



WECC-SRSG



WECC-SRSG Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	89	89	89	89	89	89	89	89	89	89
Coal	7,385	7,385	7,385	7,385	7,385	7,385	7,385	7,385	7,385	7,385
Geothermal	635	635	635	635	635	635	635	635	635	635
Hydro	794	794	794	794	794	794	794	794	794	794
Natural Gas	17,631	17,550	17,550	17,469	17,273	17,273	17,273	17,273	16,949	16,949
Nuclear	3,217	3,217	3,217	3,217	3,217	3,217	3,217	3,217	3,217	3,217
Other	51	51	51	51	51	51	51	51	51	51
Petroleum	307	307	307	227	227	227	227	227	227	227
Pumped Storage	128	128	128	128	128	128	128	128	128	128
Solar	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125
Wind	162	162	162	162	162	162	162	162	162	162
Total	31,523	31,442	31,442	31,281	31,085	31,085	31,085	31,085	30,761	30,761

Probabilistic Assessment Overview: All WECC Areas

The text in this section applies to all WECC areas.

- **Probabilistic vs. Deterministic Assessments:** The main difference between deterministic and ProbAs is their respective import transfer logic. The deterministic assessment imports available energy so that the expected values of demand and resource distributions produce a margin at or above the reference margin; the ProbA imports available energy to separate the tails of the demand and resource distributions.
    - **Demand:** Both assessments use the same hourly demand forecast derived from monthly peak and energy values provided by the region's Balancing Authorities. The ProbA applies uncertainty distributions around the expected demand derived from hourly historical demand.
    - **Thermal Resources:** Both assessments use the same resources; however, the ProbA derates the expected peak hour capacity based on historical derate values utilized in the two-state Monte-Carlo simulation.
    - **Variable Energy Resources:** Both assessments use the same expected hourly generation profiles. The ProbA applies variance distributions derived from historical generation output associated with each hour.
    - **Transmission:** Both assessments use the same topology. The ProbA imports available resources to reduce loss-of-load probability while the deterministic assessment imports available resources to meet reference margins.

Probabilistic Assessment Overview: WECC-AB

- **General Overview:** Reserve margins for the WECC-AB area are over 23 percent in 2020 and 19 percent in 2022, resulting in insignificant levels of LOLH and EUE.
- **Modeling:** WECC utilizes the Multiple Area Variable Resource Integration Convolution (MAVRIC) model, an 8,760-hourly demand, generation, and transmission sequential convolution model consisting of 39 interconnected areas:
  - Annual peak demand in the WECC-AB area ranges between approximately five percent below to five percent above forecasted demand based upon the 10 percent and 90 percent points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation by utilizing unit-specific average forced outage rates and failure durations, which is equivalent to derating WECC-AB thermal generating resources by two percent on average.
  - Hydro units in WECC-AB (storage capable, run-of-river, and pump storage) follow an hourly expected generation curve derived from historical generation output associated with each hour. Each type of hydro unit is modeled separately with a combined ~65 percent derate for storage capable and run-of-river resources.
  - Variable energy resources (wind and solar) in WECC-AB are capacity resources modeled as expected hourly generation profiles with variance distributions derived from historical generation output associated with each hour. Wind resources have an expected peak hour derate of ~45 percent, and solar resources have an expected peak hour derate of ~100 percent.

Base Case Study

- WECC-AB resource adequacy measures are zero in the Base Case, indicating that operable reserves above 20 percent for the peak hour are sufficient to have zero expected LOLH or EUE for all hours of the year.
- **Results Trending:** 2020 Annual Probabilistic Indices are unchanged from the 2016 ProbA, at 0.00.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	29.6	25.9	23.4
Prospective	11.0	11.0	10.0
Reference	26.8	23.2	19.9
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Probabilistic Assessment Overview: WECC-BC

- **General Overview:** Reserve margins for the WECC-BC area are over 20 percent in 2020 and 22 percent in 2022, resulting in insignificant levels of LOLH and EUE.
- **Modeling:** WECC utilizes the MAVRIC model, an 8760-hourly demand, generation, and transmission sequential convolution model consisting of 39 interconnected areas:
  - Annual peak demand in the WECC-BC area ranges between approximately five percent below to nine percent above forecasted demand based upon the 10 percent and 90 percent points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation by utilizing unit-specific average forced outage rates and failure durations, which is equivalent to derating WECC-BC thermal generating resources by one percent on average.
  - Hydro units in WECC-BC (storage capable, run-of-river, and pump storage) follow an hourly expected generation curve derived from historical generation output associated with each hour. Each type of hydro unit is modeled separately with a combined ~25 percent derate for storage capable and run-of-river resources.
  - Variable energy resources (wind and solar) in WECC-BC are capacity resources modeled as expected hourly generation profiles with variance distributions derived from historical generation output associated with each hour. Wind resources have an expected peak hour derate of ~88 percent, and solar resources have an expected peak hour derate of ~100 percent.

Base Case Study

- WECC-BC resource adequacy measures are zero in the Base Case, indicating that operable reserves above 20 percent for the peak hour are sufficient to have zero expected LOLH or EUE for all hours of the year.
- **Results Trending:** 2020 Annual Probabilistic Indices are unchanged from the 2016 ProbA at 0.00.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	12.4	18.7	15.9
Prospective	12.1	13.0	13.0
Reference	11.1	20.4	22.2
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Probabilistic Assessment Overview: WECC-CAMX

- **General Overview:** Reserve margins for the WECC-CAMX area are over 19 percent in 2020 and 22 percent in 2022; however, due in part to the changing resource mix, LOLH are projected for 2020 (9) and 2022 (95). Additionally, the EUE for both years increased, with ~14k MWh projected for 2020 and ~207k MWh projected for 2022.
- **Modeling:** WECC utilizes the MAVRIC model, an 8,760-hourly demand, generation, and transmission sequential convolution model consisting of 39 interconnected areas:
  - Annual peak demand in the WECC-CAMX area ranges between approximately 10 percent below to 23 percent above forecasted demand based upon the 10 percent and 90 percent points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation by utilizing unit-specific average forced outage rates and failure durations, which is equivalent to derating WECC-CAMX thermal generating resources by six percent on average.
  - Hydro units in WECC-CAMX (storage capable, run-of-river, and pump storage) follow an hourly expected generation curve derived from historical generation output associated with each hour. Each type of hydro unit is modeled separately with an expected peak hour derate of ~46 percent for pumped storage resources and combined ~38 percent derate for storage capable and run-of-river resources.
  - Variable energy resources (wind and solar) in WECC-CAMX are capacity resources modeled as expected hourly generation profiles with variance distributions derived from historical generation output associated with each hour. Wind resources have an expected peak hour derate of ~84 percent, and solar resources have an expected peak hour derate of ~24 percent.

Base Case Study

- WECC-CAMX resource adequacy measures are non-zero in the Base Case, indicating that operable reserves above 19 percent for the peak hour are no longer sufficient to have zero expected LOLH or EUE for all hours of the year. A changing resource mix is leading to increased risk in the area. It should be noted that with Tier 2 resources, not included in this assessment, most of the EUE would disappear.
- **Results Trending:** 2020 Annual Probabilistic Indices have increased from the 2016 ProbA.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	21.3	22.2	21.3
Prospective	16.2	12.3	12.1
Reference	21.3	19.5	22.8
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	2,783	41,468
EUE (ppm)	0.00	10.4	153.8
LOLH (hours/year)	0.00	0.13	2.3

*Represents 2016 ProbA results for 2020.

Probabilistic Assessment Overview: WECC-NWPP-US

- **General Overview:** Reserve margins for the WECC-NWPP-US area are over 16 percent in 2020 and 15 percent in 2022; however, due in part to the changing resource mix, LOLH are projected for 2020 (22) and 2022 (27). Additionally, the EUE for both years increased, with ~14k MWh projected for 2020 and ~18k MWh projected for 2022.
- **Modeling:** WECC utilizes the MAVRIC model, an 8,760-hourly demand, generation, and transmission sequential convolution model consisting of 39 interconnected areas:
  - Annual peak demand in the WECC-NWPP-US area ranges between approximately 10 percent below to 23 percent above forecasted demand based upon the 10 percent and 90 percent points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation by utilizing unit-specific average forced outage rates and failure durations, which is equivalent to derating WECC-NWPP-US thermal generating resources by 13 percent on average.
  - Hydro units in WECC-NWPP-US (storage capable, run-of-river, and pump storage) follow an hourly expected generation curve derived from historical generation output associated with each hour. Each type of hydro unit is modeled separately with an expected peak hour derate of ~79 percent for pumped storage resources and combined ~41 percent derate for storage capable and run-of-river resources.
  - Variable energy resources (wind and solar) in WECC-NWPP-US are capacity resources modeled as expected hourly generation profiles with variance distributions derived from historical generation output associated with each hour. Wind resources have an expected peak hour derate of ~77 percent, and solar resources have an expected peak hour derate of ~54 percent.

Base Case Study

- WECC-NWPP-US resource adequacy measures are non-zero in the Base Case, indicating that operable reserves above 16 percent for the peak hour are no longer sufficient to have zero expected LOLH or EUE for all hours of the year. A changing resource mix is leading to increased risk in the area. It should be noted that with Tier 2 resources, not included in this assessment, most of the EUE would disappear.
- **Results Trending:** 2020 Annual Probabilistic Indices have increased from the 2016 ProbA.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	30.3	23.3	20.2
Prospective	16.3	19.7	19.6
Reference	16.5	16.1	15.9
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	1,896	2,553
EUE (ppm)	0.00	6.45	8.58
LOLH (hours/year)	0.00	0.47	0.58

*Represents 2016 ProbA results for 2020.

Probabilistic Assessment Overview: WECC-RMRG

- **General Overview:** Reserve margins for the WECC-RMRG region are over 14 percent in 2020 and 12 percent in 2022, resulting in insignificant levels of LOLH and EUE.
- **Modeling:** WECC utilizes the MAVRIC model, an 8760-hourly demand, generation, and transmission sequential convolution model consisting of 39 interconnected areas.
  - Annual peak demand in the WECC-RMRG region ranges between approximately 12 percent below to 24 percent above forecasted demand based upon the 10 percent and 90 percent points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation by utilizing unit-specific average forced outage rates and failure durations, which is equivalent to derating WECC-RMRG thermal generating resources by seven percent on average.
  - Hydro units in WECC-RMRG (storage capable, run-of-river, and pump storage) follow an hourly expected generation curve derived from historical generation output associated with each hour. Each type of hydro unit is modeled separately with an expected peak hour derate of ~91 percent for pumped storage resources and combined ~46 percent derate for storage capable and run-of-river resources.
  - Variable energy resources (wind and solar) in WECC-RMRG are capacity resources modeled as expected hourly generation profiles with variance distributions derived from historical generation output associated with each hour. Wind resources have an expected peak hour derate of ~80 percent, and solar resources have an expected peak hour derate of ~16 percent.

Base Case Study

- WECC-RMRG resource adequacy measures are zero in the base case, indicating that operable reserves above 18 percent for the peak hour are sufficient to have zero expected LOLH or EUE for all hours of the year.
- **Results Trending:** 2020 Annual Probabilistic Indices are unchanged from the 2016 ProbA, at 0.00.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	21.7	27.8	24.7
Prospective	14.0	16.8	16.4
Reference	17.8	20.8	18.5
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Probabilistic Assessment Overview: WECC-SRSG

- **General Overview:** Reserve margins for the WECC-SRSG area are over 21 percent in 2020 and 16 percent in 2022, resulting in insignificant levels of LOLH and EUE.
- **Modeling:** WECC utilizes the MAVRIC model, an 8,760-hourly demand, generation, and transmission sequential convolution model consisting of 39 interconnected areas:
  - Annual peak demand in the WECC-SRSG area ranges between approximately 12 percent below to 24 percent above forecasted demand based upon the 10 percent and 90 percent points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation by utilizing unit-specific average forced outage rates and failure durations, which is equivalent to derating WECC-SRSG thermal generating resources by nine percent on average.
  - Hydro units in WECC-SRSG (storage capable, run-of-river, and pump storage) follow an hourly expected generation curve derived from historical generation output associated with each hour. Each type of hydro unit is modeled separately with an expected peak hour derate of ~47 percent for pumped storage resources and combined ~27 percent derate for storage capable and run-of-river resources.
  - Variable resources in WECC-SRSG are capacity resources modeled as expected hourly generation profiles with variance distributions derived from historical generation output associated with each hour. Wind resources have an expected peak hour derate of ~82 percent, and solar resources have an expected peak hour derate of ~20 percent.

Base Case Study

- WECC-SRSG resource adequacy measures are zero in the Base Case, indicating that operable reserves above 15 percent for the peak hour are sufficient to have zero expected LOLH or EUE for all hours of the year.
- **Results Trending:** 2020 Annual Probabilistic Indices are unchanged from the 2016 ProbA at 0.00.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	21.2	32.0	26.8
Prospective	15.8	15.1	14.6
Reference	20.4	20.1	16.7
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: The Reference Margin Level is established by WECC through a Building Block method, which was created by the Loads and Resource Subcommittee. The Building Block method is not a 1-in-10 loss of load probabilistic study approach, but is created by identifying four elements that contribute to planning reserves (contingency reserves, regulating reserves, forced outages, and a high temperature adder). No WECC subregion drops below the Reference Margin Level during the assessment period.

Demand: Load forecasts are developed by WECC staff by imposing the monthly peak and energy forecasts provided by the 38 individual BAs on BA specific annual hourly (8,760 hours) curves. The BAs update the peak and energy forecasts annually based on expected population growth, with expected economic conditions, and normalized weather conditions. Forecasted demand is reduced for rooftop solar to reflect demand expected to be served by the LSE. The forecasted curves are aggregated to subregional and to Western Interconnection curves to create the coincidental peak for the study cases. The CA/MX subregion has forecasted relatively flat peak demand growth over the next 10 years (0.27 percent), primarily due to the projected increases in rooftop solar installations. Other WECC subregions show growth rates between 0.62 percent and 1.88 percent, which is in line with historic demand forecasts.

Demand-Side Management: A significant portion of the controllable DR programs within WECC are associated with large industrial facilities, air conditioner cycling programs, and water pumping—both canal and underground potable water and for irrigation use. These programs are created by LSEs who are responsible for their administration and execution when needed. In some areas, the programs are market driven (CAISO and AESO) and can be called upon for economic considerations. However, most areas in the Western Interconnection are not parties to organized markets, and DSM programs are approved by local authorities and used only for the benefit of the approved LSE. DSM programs in WECC often have limitations, such as limited number of times they can be called on and some can only be activated during a declared local emergency.

Entities within WECC are not forecasting a significant increase in controllable DR. CAISO's DR initiative programs are being developed with a goal to avoid adverse long-term reliability impacts.

EE and conservation are viewed as a permanent reduction in demand and are reflected as reductions in the load growth forecasts. WECC does not know the explicit demand reductions associated with these programs as those programs are administered by the individual LSEs or ISOs and not by WECC.

Distributed Energy Resources: The impacts of DERs on individual LSEs are well understood and are included in local assessments. For example, CAISO has approximately 5,000 MW of rooftop solar and must proportionally increase reserves to respond to a sudden increase in demand associated with cloud cover or rain. Historically, an increase in cloud cover would cause a decrease in demand, but a loss of rooftop solar has the opposite effect and demand increases. Rooftop solar in California is well dispersed throughout the state, which reduces the expectations of widespread generation disruptions due to cloud cover.

It is estimated that there was about 5,500 MW of rooftop solar installed throughout the Western Interconnection at the end of 2016. That number is forecasted to increase to over 10,000 MW by the end of 2022 and over 17,000 MW by the end of 2027. CAISO expects to have nearly 13,000 MW of rooftop solar installed in their footprint by the end of 2027.

Many power flow models can include DERs as a data input, but currently none of these models have been approved for use in the Western Interconnection. WECC's MVWG is in the process of approving these models for future use.

Generation: In 2015 the *Western Interconnection Flexibility Assessment*[76] was published, which examines the ability of the western grid to reliably function with the anticipated increase in variable generation. Although this assessment has not been updated, the conclusions presented in this paper appear to remain valid under the current and high-renewable RPS requirements.

CAISO has also started a stakeholder process to create a flexible resource element in the California market.

For reliability assessments, WECC applies variable resource capacity discounts based on historic on-peak generation. This process involves identifying the expected summer and winter peak hour for each assessment year and applying the historic five-year average wind and solar capacity factors associated with that specific hour. WECC's annual update of the base historical data leads to minor changes in discounts, but the process itself has not been changed for this year's assessment. The method for counting capacity contribution is the same for all resource tiers, but the variability in historic seasonal peak hour generation may produce different capacity factors for each assessment year.

WECC studies expected future study cases that include expected generation retirements. Although it is anticipated that older coal-fired resources will retire in coming years, it is not expected that there will be excessive unplanned re-

[76] WECC Flexibility Assessment Report.

tirements that cause a severe impact to reliability as these retirements would need approval from state PUCs or ISOs. Individual LSEs and BAs perform retirement studies to determine whether retirements are feasible or to determine the potential impacts to reliability. WECC also develops and compiles 11 Base Cases to be built for the current year study cycle. Those cases include heavy and light load scenarios that are used by the Transmission Planners (TPs) and Planning Coordinators to study extreme retirement scenarios.

WECC is not a planning entity and does not approve or reject planned retirements. However, WECC does incorporate announced and planned retirements when creating datasets to be used in planning models. Retirement of generation resources is not currently a major concern as ample generation exists in the Western Interconnection. However, that condition could change over the assessment period. WECC monitors generation retirements and studies the potential impacts to Interconnection-wide reliability associated with announced or planned retirements. The large geographic footprint of the Western Interconnection helps mitigate generation retirements as seasonal transfers from winter-peaking areas to summer-peaking areas and vice versa are very common in the Western Interconnection.

Individual state PUCs or the appropriate ISOs conduct studies to determine impacts to reliability. Actual retirements in 2016 were relatively minimal with 475 MW of natural gas fired and 290 MW of coal-fired generation retired. Several large generating units (e.g., the coal-fired Intermountain Power Project, the Navajo power plant, and the Diablo Canyon nuclear station) are being considered for future retirement.[77]

All natural-gas-fired units are included as available resources when performing resource adequacy assessment, but WECC performs scenario studies modifying the availability of resources. WECC has studied and continues to study the potential impacts to electric reliability associated with the limited availability of the Aliso Canyon natural gas storage facility. Aliso Canyon has been available at a limited capacity for nearly two years and, during that time, there have been no electric outages caused by the reduced storage availability. CAISO continues to work with the impacted natural gas company and the neighboring BAs and RCs to provide mitigation plans to minimize and eliminate the risk to the reliability of the electric transmission grid.

[77] These units were not included as certain retirements in this assessment because these retirements were not reported to WECC as they do not qualify for retirements under market rules, or these planned retirements have not been finalized and regulatory approval has not been received. These retirements are included as potential retirements in this assessment and are reflected in the potential reserve margin.

Capacity Transfers: WECC's assessment process is based on system-wide modeling that aggregates BA-based load and resource forecasts by geographic subregions with conservatively-assumed power transfer capability limits between the zones. The Resource Adequacy Assessment Model calculates transfers between the zones limited to the lesser of excess capacity above the margin needed in the transferring zone or the conservative transmission limit.[78]

Resources that are physically located in one BA area but are owned by an entity or entities located in another BA's geographic footprint are modeled as remote resources. These resources are modeled with transmission links between the resource zone and the owner's zone that are limited to the owner's share of the resource. This treatment allows the owner of the resource, and only the owner, to count the resource for margin calculations. Remote resources are transferred first in WECC's modeling processes and reduce the capacity available for modeled transfers.

The reliability assessments performed by WECC are done with conservative seasonal transfer limits. Therefore, the transfer limits included in the LTRA are studied at less than optimal levels and reflect limited and conservative transfers. Transfers with other regional councils, such as MRO and SPP, are not included in this assessment as this would require an assumption regarding the amount of surplus or deficit generation in those councils.

[78] Transfers from existing and Tier 1 resources are classified as firm transfers, and transfers from Tier 2 and Tier 3 resources are classified as nonfirm transfers. This modeling approach ensures that resources are only counted once within the Region.

Transmission Planning: Transmission planning in the Western Interconnection is coordinated by five[79] regional planning groups that create and periodically publish transmission expansion plans: Northern Tier Transmission Group,[80] WestConnect,[81] ColumbiaGrid,[82] California ISO,[83] and Alberta Electric System Operator.[84] Several entities have proposed major transmission projects to connect renewable resources on the eastern side of the Western Interconnection to load centers on the Pacific Coast to help satisfy renewable portfolio standards, particularly in California. These projects, however, are often subject to significant development delays due to permitting and other issues. Currently, it is not anticipated that transmission additions will be needed to maintain reliability in the Western Interconnection during the assessment period, but transmission additions will continue to interconnect renewable resources.

Individual LSEs and BAs perform extreme weather scenario studies to determine the potential impacts to reliability. WECC develops the base case compilation schedule that details the 11 cases to be built for the current year study cycle. Those cases include heavy and light load scenarios that are used by the TP and Planning Coordinator to study extreme weather scenarios.

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79 A sixth regional planning group, The British Columbia Coordinated Planning Group (BCCPG), enables coordination and, where appropriate, integration of the transmission planning functions of transmission owner members. There is no consolidation of the members' long-term transmission plans, however. BCCPG members include; British Columbia Hydro and Power Authority, FortisBC, Rio Tinto Alcan Inc., Tech Metals Ltd., and Columbia Power Corporation.

80 https://www.nttg.biz/site/index.php?option=com_content&view=article&id=372&Itemid=135

81 https://doc.westconnect.com/Documents.aspx?NID=12

82 https://www.columbiagrid.org/notices-detail.cfm?NoticeID=148

83 http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf

84 https://www.aeso.ca/assets/Uploads/2015-Long-termTransmissionPlan-WEB.pdf

Data Concepts and Assumptions

Demand (Load Forecast)	
Total Internal Demand	The peak hourly load for the summer and winter of each year. Projected total internal demand is based on normal weather (50/50 distribution)[2] and includes the impacts of distributed resources, EE, and conservation programs.[3]
Net Internal Demand	Total internal demand, reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[4]**	**Load Forecasting Entity**
FRCC	Summer	Noncoincident	FRCC LSEs
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
NPCC-Maritimes	Winter	Noncoincident	Maritimes Sub Areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro Québec
PJM	Summer	Coincident	PJM
SERC-E	Summer	Noncoincident	SERC LSEs
SERC-N	Summer	Noncoincident	SERC LSEs
SERC-SE	Summer	Noncoincident	SERC LSEs
SPP	Summer	Noncoincident	SPP LSEs
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AESO	Winter	Noncoincident	Individual BAs: aggregated by WECC
WECC-BC	Winter	Noncoincident	Individual BAs: aggregated by WECC
WECC-CAMX	Summer	Noncoincident	Individual BAs: aggregated by WECC
WECC-NWPP-US	Summer	Noncoincident	Individual BAs: aggregated by WECC
WECC-RMRG	Summer	Noncoincident	Individual BAs: aggregated by WECC
WECC-SRSG	Summer	Noncoincident	Individual BAs: aggregated by WECC

Resource Categories
NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy:
Anticipated Resources: • Existing-certain generating capacity (includes operable capacity expected to be available to serve load during the peak hour with firm transmission) • Tier 1 capacity additions (includes capacity that is either under construction or has received approved planning requirements) • Firm capacity transfers (imports minus exports) with firm contracts • Less confirmed retirements[5]
Prospective Resources (including all anticipated resources plus the following): • Existing-other capacity (includes operable capacity that could be available to serve load during the peak hour, but lacks firm transmission and could be unavailable during the peak or a number of reasons) • Tier 2 capacity additions (includes capacity that has been requested but not received approval for planning requirements) • Expected (nonfirm) capacity transfers (imports minus exports): transfers without firm contracts, but a high probability of future implementation • Less unconfirmed retirements[6]

Planning Reserve Margins	
Planning Reserve Margins	The primary metric is used to measure resource adequacy, defined as the difference in resources (Anticipated or Prospective) and Net Internal Demand divided by Net Internal Demand, shown as a percentile.
	Anticipated Reserve Margin = (Anticipated Resources – Net Internal Demand) / Net Internal Demand Prospective Reserve Margin = (Prospective Resources – Net Internal Demand) / Net Internal Demand
Reference Margin Level	The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level a can be determined by using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand, beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels can fluctuate over the duration of the assessment period or may be different for the summer and winter seasons. If a Reference Margin Level is not provided by a given assessment area, NERC applies 15 percent for predominately thermal systems and 10 percent for predominately hydro systems.

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[1] The summer season represents June–September and the winter season represents December–February.

[2] Essentially, this means that there is a 50 percent probability that actual demand will be higher and a 50 percent probability that actual demand will be lower than the value provided for a given season/year.

[3] Coincident: The sum of two or more peak loads that occur in the same hour. Noncoincident: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

[4] Coincident: The sum of two or more peak loads that occur in the same hour. Noncoincident: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

[5] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

[6] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

TAB 18

NPCC 2018 Ontario Comprehensive Review Of Resource Adequacy

FOR THE PERIOD FROM 2019 TO 2023
APPROVED BY THE RCC ON DECEMBER 4, 2018

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Document Change History

Issue	Reason for Issue	Date
1.0	For submission to CP-8	September 25, 2018
2.0	For submission to TFCP	November 8, 2018
3.0	For submission to RCC	December 4, 2018

1 EXECUTIVE SUMMARY

The Independent Electricity System Operator (IESO) submits this assessment of resource adequacy for the Ontario Area to comply with the Reliability Assessment Program established by the Northeast Power Coordinating Council (NPCC). The 2018 Comprehensive Review of Resource Adequacy covers the study period from 2019 through 2023 and supersedes previous reviews.

Since the last Comprehensive Review conducted in 2015, 2,320 megawatts (MW) of new generation capacity has been added in Ontario. Capacity additions include 1,487 MW of wind, 342 MW of gas, 340 MW of solar, 81 MW of hydroelectric, 40 MW of biofuel and 31 MW of nuclear generation.

Another 1,710 MW of generating resource capacity is either under construction or planned to come into service, while 1,405 MW of capacity is expected to retire over the horizon of this study, in comparison to the existing installed capacity as of August 2018.

The IESO determines Ontario's level of resource adequacy using the General Electric Multi-Area Reliability Simulation (GE-MARS) program and applies the NPCC criterion that requires a loss of load expectation (LOLE) value of no more than 0.1 days/year for study years.

The results presented in Table 1.1 show that the NPCC LOLE criterion is satisfied for Median Demand Growth scenario. Dashes indicate scenarios that were not assessed, as the NPCC criterion was satisfied using a more conservative scenario. The NPCC criterion is satisfied for 2019 and 2020 with existing and planned resources, based on the existing outage plan. For 2021 and 2022, it will be necessary to reschedule outages and rely on Emergency Operating Procedures (EOPs) to satisfy the NPCC criterion. In 2023, the use of up to 100 MW of tie benefits will be required to satisfy the criterion. For the High Demand Growth scenario, the NPCC criterion is satisfied for 2019 with existing and planned resources. For 2020 onwards, outage rescheduling, EOPs and tie benefits are required to meet the LOLE criterion.

Table 1.1 Annual LOLE Values, Median and High Demand Forecast

Scenario	EOPs	Outages Rescheduled	Tie Benefits (MW)	LOLE [days/year]				
				2019	2020	2021	2022	2023
Median	No	No	0	0.002	0.099	0.389	0.337	0.506
	Yes	No	0	-	-	0.133	0.115	0.159
	Yes	Yes	0	-	-	0.015	0.015	0.107
	Yes	Yes	100	-	-	-	-	0.087
High	No	No	0	0.003	0.423	2.491	3.884	9.941
	Yes	No	0	-	0.129	1.129	1.881	4.813
	Yes	Yes	0	-	0.110	0.308	0.716	4.345
	Yes	Yes	1,300	-	0.008	0.030	0.097	0.873
	Yes	Yes	3,050	-	-	-	-	0.095

Major assumptions used in the assessment are summarized in Table 1.2.

Table 1.2 Major Assumptions

Assumption	Description
Adequacy Criterion	NPCC Loss of Load Expectation (LOLE) requirement of not more than 0.1 days/year
Study Period	January 1, 2019 to December 31, 2023
Reliability Model	GE's MARS program
Load Model	8,760 hourly loads with monthly forecast uncertainty factors
Energy Demand Growth Rate	Median Demand Growth: -0.2% per annum (average) High Demand Growth: +2.5 % per annum (average)
Installed Generating Capacity Additions	1, 711 MW by the end of 2023, compared to Summer 2018 (shown in Table A.3)
Installed Generating Capacity Retirements	1,405 MW of capacity by the end of 2023, of which 1,030 MW are the retirement of the Pickering A Nuclear Generating Station at the end of 2022.
Internal Transmission Constraints	10-zone transmission model with IESO's normal system operating security limits applied on interfaces between zones
Tie Benefits (i.e. non-firm imports)	Tie benefits used as needed
Firm Contracts	500 MW to Quebec in winter months, December to March, until 2023. 500 MW from Quebec in summer months (June 1 to September 30) of 2023. Ontario has an agreement with Quebec where Quebec will provide Ontario a total of 500 MW of capacity in the summer to be exercised, when needed, any time before September 30, 2030. This capacity may be used once or be split into multiple summer periods, but cannot exceed 500 MW in total (e.g. 100 MW may be used in one year and 400 MW in another year). For this study, it is expected that the IESO will make use of the entirety of the 500 MWs over the summer of 2023.
Emergency Operating Procedures	Public appeal, operating reserve, and voltage reduction Aggregated net impact of EOPs: 3.2% of demand
Unit Availability	Planned outages are based on outage submissions from market participants. Nuclear refurbishment schedule is based on information provided by nuclear operators, as of 2017. Sensitivity studies were performed for keeping planned outages 'as is' vs. moving them for when reliance on tie-benefits was needed. Equivalent Demand Forced Outage Rates ($EFOR_d$) are derived from a rolling five-year history of actual forced outages and forced derates. Units with insufficient historical data are based on either forecast $EFOR_d$ from market participants or similar units.
Energy Efficiency and Embedded Generation	Used as load modifiers and reflected in the demand forecast. Energy Efficiency (incremental from 2018): Up to 556 MW by 2023 Embedded Generation: Up to 3,750 MW by 2023
Demand Management	Used as a resource. 533 MW of effective summer capacity at peak.

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3 INTRODUCTION

The 2018 Comprehensive Review of Resource Adequacy for Ontario is submitted to the Northeast Power Coordinating Council (NPCC) in accordance with Appendix D of the NPCC Regional Reliability Reference Directory #1, *"Design and Operation of the Bulk Power System."*

This report was prepared by the Independent Electricity System Operator (IESO) in its role as the Planning Coordinator for Ontario.

The 2018 Comprehensive Review of Resource Adequacy covers the study period from 2019 through 2023 and supersedes previous reviews. The previous Comprehensive Review was approved by the NPCC Reliability Coordinating Committee in December 2015 and covered the 2016 to 2020 period. Interim Reviews were provided in 2016 and 2017.

3.1 Comparison of 2018 vs. 2015 Comprehensive Review

3.1.1 Demand Forecast

Tables 3.1 and 3.2 show a comparison between the peak demand forecasts for the 2015 Comprehensive Review and the 2018 Comprehensive Review under Median and High Demand Growth scenarios for the overlapping years. These tables also present peak demand forecasts for the years 2019 to 2023.

Table 3.1 Comparison of Demand Forecasts: Normal Weather Summer Peak (MW)

Year	Normal Weather Summer Peak					
	Median Demand Growth			High Demand Growth		
	2015 Review	2018 Review	Difference	2015 Review	2018 Review	Difference
2019	22,669	22,016	-653	24,936	22,236	-2,700
2020	22,522	22,085	-437	24,886	22,969	-1,917
2021		22,155			23,750	
2022		22,098			24,308	
2023		22,139			24,796	
Average Growth Rate	-0.65%	0.14%		-0.20%	2.76%	

Table 3.2 Comparison of Demand Forecasts: Normal Weather Winter Peak (MW)

Year	Normal Weather Winter Peak					
	Median Demand Growth			High Demand Growth		
	2015 Review	2018 Review	Difference	2015 Review	2018 Review	Difference
2019	21,423	21,328	-95	23,565	21,541	-2,024
2020	21,307	21,317	10	23,544	22,169	-1,375
2021		21,305			22,839	
2022		21,165			23,282	
2023		21,273			23,826	
Average Growth Rate	-0.54%	-0.06%		-0.09%	2.55%	

Over the forecast period, Ontario energy demand is expected to increase by about 0.1% annually under the median demand forecast, and increase by about 2.5% annually under the high demand forecast.

Ontario demand is broadly shaped by a number of factors: economic growth, population growth, energy efficiency savings, price impacts and embedded[1] generation. Each factors' impact varies based on the season and whether it is peak, energy or minimum demand.

Since the 2015 Comprehensive Review the provincial economy has grown, led by the service and construction sectors, areas that are not electrically intense. Of the six electrically intense industrial sectors, only iron and steel fabrication has seen an increase in demand. Recently those large electricity consumers have seen an increase in consumption and the current economic climate is more favourable to those sectors. A strong U.S. economy, low Canadian dollar and low interest rates all help Ontario's export-oriented energy intensive industries. Potential future trade disruptions produce uncertainty on the broader Ontario economy.

Over the forecast horizon, both the summer and winter peaks are expected to remain virtually flat under the Median Demand Growth scenario. This is due to strong downward pressure from peak pricing incentives, increased energy efficiency savings and growth in embedded generation output.

[1] Embedded Generation refers to distributed generation that does not participate in the IESO-Administered Market. Outputs from these resources are estimated using metered data from generators greater than 5 MW, monthly energy estimates from local distribution companies and contract data for those that have contracts with the IESO. The output is then netted from the demand forecast used in this study.

Previously, peaks were expected to decline significantly due to growth in embedded generation. With the expansion of embedded capacity plateauing, this downward impact has also lessened.

In the High Demand Growth scenario both the winter and summer peaks are expected to grow over the forecast horizon, as the positive economic environment spurs electricity demand. The High Demand Growth considers growth of energy intensive year-round industries, such as prospective mining growth, in its forecast. At the same time, the factors offsetting growth – embedded generation, electricity prices and energy efficiency – are not strong enough to offset the underlying growth.

In both the Median and High Growth forecasts, the effect of price-responsive loads reducing on their own under the Industrial Conservation Initiative (ICI) are included. An estimate of an additional 1,400 MW of price-responsive demand is incorporated in the demand forecast. This is a result of price-responsive loads reducing on their own under the ICI[2].

Although point forecasts are presented for both the Median and High Demand Growth scenarios, each scenario has an associated "uncertainty" distribution which recognizes the variability of demand due to weather volatility.

3.1.2 Resources Forecast

Table 3.3 shows how the available capacity of supply resources has changed compared with the 2012 Comprehensive Review.

Table 3.3: Comparison of Available Resources Forecasts (MW)

Year	Summer Peak			Winter Peak		
	2015 Review	2018 Review	Difference	2015 Review	2018 Review	Difference
2019	27,687	28,648	961	30,133	28,884	-1,249
2020	28,560	26,477	-2,083	30,122	29,446	-676
2021		25,362			28,864	
2022		26,076			29,191	
2023		25,638			27,846	

[2] Industrial Conservation Initiative (ICI) is a form of demand response that incents participating customers to reduce demand during peak periods. Customers who participate in the ICI, referred to as Class A, pay global adjustment costs based on their percentage contribution to the top five peak Ontario demand hours (i.e., peak demand factor) over a 12-month base period. The threshold for participation in this program has changed since 2015 and as a result, its impact has increased since the 2015 Comprehensive Review. The current threshold for participation includes consumers with an average peak demand greater than 1 MW and consumers in the manufacturing and industrial sectors, including greenhouses with an average monthly peak demand of greater than 500 kW and less or equal to 1 MW are eligible to opt-in to the ICI.

The differences in available resources between 2018 Comprehensive Review and 2015 Comprehensive Review are primarily due to the factors below.

- Changes to nuclear outage and refurbishment schedules, along with minor revisions to available capacity at nuclear generators, led to a 1,506 MW increase in available nuclear capacity on summer peak in 2019 and a 1,467 MW decrease in available nuclear capacity for summer peak in 2020.
- Since 2015, Ontario's Ministry of Energy, Northern Development and Mines has issued several directives to the IESO that created a reduction in the projected installed capacity of hydroelectric, wind, solar and biofuel generation resources. These resources have also been affected by attrition in new projects, changes to in-service dates, and updates to resource contributions.
- In terms of available capacity on summer peak in 2019, the changes above result in a 140 MW reduction in hydroelectric resources, a 77 MW reduction in wind resources, a 46 MW reduction in biofuel resources and an 85 MW reduction in solar resources.
- The shutdown of the Thunder Bay Generating Station reduced the available biofuel capacity by a further 153 MW.
- A 43 MW reduction in summer peak Demand Response since the 2015 Comprehensive Review; this is due to changes in resource availability and the implementation of the IESO's Demand Response Auction.

The remaining differences in resources are from changes in outage schedules including changes to the nuclear refurbishment schedules.

From 2021 to 2023, the forecast does not include any new generation resources. There are no directives or procurement activities that contemplate technology specific resources that may be built beyond 2020 in Ontario. All contracted generation from previous procurement activities are expected to be in-service by the end of 2020 and are incorporated in the resources forecast. Year to year variation of available resources from 2021 to 2023 are therefore driven by outages, including outages related to nuclear refurbishment and the shutdown of Pickering Nuclear Generating Station. The IESO is developing an incremental capacity auction which will be technology agnostic to address resource adequacy needs that may in the future.

- End of Section -

4 RESOURCE ADEQUACY CRITERION

4.1 Criterion Statement and Application

The IESO uses the NPCC resource adequacy criterion from Directory #1 to assess the adequacy of resources in the Ontario Planning Coordinator Area:

> *"**R4** Each Planning Coordinator or Resource Planner shall probabilistically evaluate **resource** adequacy of its Planning Coordinator **Area** portion of the **bulk power system** to demonstrate that the loss of **load** expectation (LOLE) of disconnecting **firm load** due to **resource** deficiencies is, on average, no more than 0.1 days per year.*
>
> ***R4.1** Make due allowances for **demand** uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator **Areas**, transmission transfer capabilities, and **capacity** and/or **load** relief from available operating procedures."*

The IESO uses the Load Forecast Uncertainty (LFU) associated with the normal weather demand forecast for this assessment, which captures the variability of the weather scenario. The LFU is modelled through the use of probability distribution.

Scheduled and forced outages/deratings to Ontario generators are assessed by considering submissions by generator owners, actual historic outage observations and more generalized outage factors.

Ontario's interconnections with Manitoba, Minnesota, Quebec, New York and Michigan and the resultant tie-benefits are used as needed, within the constraints of the inter-tie transfer capabilities and the most recent NPCC Tie Benefits Study[3].

Emergency operating procedures (EOPs) are used in the resource adequacy assessment if the existing and planned resources are not sufficient to meet the Loss of Load Expectation (LOLE) criterion. Table 4.1 summarizes the assumptions regarding the load relief from EOPs used when required in this study. For this study, all EOPs are applied in one block.

To meet the criteria for the period of consideration, use of EOPs are required in this study for some calendar years and demand scenarios.

The results of this report showing that Ontario will meet its LOLE criterion over the next five years are consistent with the results of previous studies, which include the 2015 Comprehensive Review, and the 2016 and 2017 Interim Reviews.

[3] NPCC, Review of Interconnection Assistance Reliability Benefits, December 31, 2015

Table 4.1 Emergency Operating Procedure Assumptions

EOP Measure	EOP Impact (% of Demand)
Public Appeals	1.0
No 30-minute OR (473 MW)	0*
No 10-minute OR (945 MW)	0*
Voltage Reductions	2.2
Aggregated Net Impact	**3.2**

* Although 30-minute and 10-minute OR are included in this list of EOPs, the analysis does not impose a requirement to provide for OR since only loss of load events are being considered. Therefore, the net benefit of applying EOPs in the analysis excludes relaxation of OR requirements.

4.2 Resource Requirements to Meet the Criteria

The Ontario resource mix is well-balanced with a variety of fuel types. A diverse generation mix is important for resource adequacy and market efficiency, because it provides dispatch flexibility and reduced vulnerability to fuel supply contingencies.

The expected installed capacity mix at the time of the summer peak for each year of the study period is listed in Table 4.2. Tables 4.3 and 4.4 show installed capacity summer peaks and winter peaks for the study period. These values do not include generators that operate within local distribution service areas (embedded generation), except for those that participate in the IESO-administered market. The resource forecast is based on information available to the IESO as of July 2018.

Table 4.2 Ontario Expected Installed Capacity Mix by Fuel Type (%) at Peak Day

Fuel Type \ Year	2019	2020	2021	2022	2023
Nuclear	33.3%	33.1%	33.1%	33.1%	31.4%
Gas / Oil*	28.4%	28.3%	28.3%	28.3%	29.0%
Hydroelectric	21.9%	21.9%	21.9%	21.9%	22.5%
Wind	12.2%	12.6%	12.6%	12.6%	13.0%
Biofuel	0.8%	0.8%	0.8%	0.8%	0.7%
Solar	1.2%	1.2%	1.2%	1.2%	1.2%
Demand Side Management	2.2%	2.2%	2.2%	2.2%	2.2%

* The Gas / Oil category includes 2,100 MW of dual-fuel capability at Lennox Station.

Table 4.3: Installed Capacity at Summer Peak (MW)

Fuel Type	2019	2020	2021	2022	2023
Nuclear	13,009	13,009	13,009	13,009	11,979
Gas / Oil*	11,118	11,118	11,118	11,118	11,075
Hydroelectric	8,560	8,590	8,590	8,590	8,590
Wind	4,787	4,947	4,947	4,947	4,947
Biofuel	295	295	295	295	257
Solar	463	463	463	463	463
Demand Side Management	857	857	857	857	857
Total	39,088	39,278	39,278	39,278	38,167

Table 4.4: Installed Capacity at Winter Peak (MW)

Fuel Type	2019	2020	2021	2022	2023
Nuclear	13,009	13,009	13,009	13,009	11,979
Gas / Oil*	11,118	11,118	11,118	11,118	11,075
Hydroelectric	8,560	8,590	8,590	8,590	8,590
Wind	4,487	4,787	4,947	4,947	4,947
Biofuel	295	295	295	295	295
Solar	380	463	463	463	463
Demand Side Management	998	998	998	998	998
Total	38,846	39,260	39,420	39,420	38,347

Resource Availability Considerations

There are several modelling techniques employed to mitigate reliability impacts resulting from the proposed resource availability.

For thermal units, Equivalent Demand Forced Outage Rates ($EFOR_d$) for existing units is derived using rolling five-year history of actual forced outages. This ensures that nuclear, gas/oil and biofuel units' random derates and forced unavailability are represented in the MARS model.

Hydroelectric resources are modelled in MARS as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity and monthly energy values are based on historical production and contribution values.

By the end of 2023, about 4,947 MW of grid-connected wind-powered generation is expected to be in-service in Ontario. The wind generation capacity contribution is substantially discounted from the nameplate value and represented in the MARS study as a probabilistic model developed on a zonal basis with a cumulative probability density function (CPDF).

There are two main demand management mechanisms in Ontario: DR and Dispatchable Loads. In order to reflect reality of demand management programs, the IESO uses effective demand management values instead of gross values. The effective values are based on historical behaviors.

Further details of capacity mix modelling and DR are provided in section 5.3 and Appendix A.3.

Tables 4.5 and 4.6 show expected available capacity at summer and winter peak for the study period. These values do not include generators that operate within local distribution service areas (embedded generation), except for those that participate in the IESO-administered market.

Resources considered in this review include all existing and planned resources expected to be in service during the review period. Planned resources include all committed projects under contract with the IESO.

Available resources are determined based on the following:

1) Historical median contribution of hydro resources during peak demand hours;

2) Total capacity available from thermal units (nuclear, gas, oil and biofuel) after discounting for seasonal derating;

3) Historical median contribution of wind and solar resources during the peak demand hours; and

4) Effective capacity of projected demand measure resources: Demand Response (DR) and Dispatchable Loads

5) Outage schedules, including potential outages over the seasonal peak. The majority of outages that occur over the peak period are due to the refurbishment of nuclear generators, whose outages last 2-3 years per generator. The nuclear refurbishment schedule is shown in the figure below.

Table 4.5: Available Capacity at Summer Peak (MW)

Fuel Type	2019	2020	2021	2022	2023
Nuclear	12,053	9,841	8,726	9,479	8,574
Gas / Oil*	9,326	9,326	9,326	9,287	9,291
Hydroelectric	5,812	5,833	5,833	5,833	5,833
Wind	603	623	623	623	623
Biofuel	274	274	274	274	236
Solar	47	47	47	47	47
DR	533	533	533	533	533
Firm Imports (+)/Exports (-)	0	0	0	0	500
Total	28,648	26,477	25,362	26,076	25,638

Table 4.6: Available Capacity at Winter Peak (MW)

Fuel Type	2019	2020	2021	2022	2023
Nuclear	10,825	10,773	10,258	10,411	8,610
Gas / Oil*	9,552	10,031	9,903	10,077	10,034
Hydroelectric	6,243	6,265	6,265	6,265	6,265
Wind	1,696	1,809	1,870	1,870	1,870
Biofuel	274	274	274	274	274
Solar	0	0	0	0	0
DR	793	793	793	793	793
Firm Imports (+)/Exports (-)	-500	-500	-500	-500	0
Total	28,884	29,446	28,864	29,191	27,846

* The Gas / Oil category includes 2,100 MW of dual-fuel capability at Lennox Station.

Figure 4.1: Nuclear Refurbishment and Projected End of Life Schedule

Firm Sales and Purchases

As part of the electricity trade agreement between Ontario and Quebec, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023 and Quebec will provide Ontario a total of 500 MW of capacity in the summer months (June to September) to be exercised, when needed, any time before September 30, 2030. This summer capacity was relied upon in this Comprehensive Review in 2023 for both Median and High Growth scenarios.

4.3 Requirements to Determine Resource Adequacy Needs

The IESO's resource adequacy criterion is defined in the Ontario Resource and Transmission Criteria and confirms that "to assess the adequacy of resources in Ontario, the IESO uses the NPCC resource adequacy design criterion."

- End of Section -

5 RESOURCE ADEQUACY ASSESSMENT

The resource adequacy probabilistic assessment is performed using GE-MARS. The following inputs were used:

- Median and high demand growth forecast and associated load forecast uncertainty (LFU);
- Forecast of available resources and existing EOPs;
- Planned outage schedules submitted by market participants;
- Equivalent demand forced outage rates ($EFOR_d$) for thermal units derived using historical generator performance data; and
- Transmission limits of major interfaces connecting different zones.

The above inputs are described in greater detail in Appendix A of this report. Sensitivity studies are performed for keeping planned outages 'as is' vs. moving them for situations where reliance on tie-benefits was needed.

5.1 Assessment Results

The results for the Median and High Demand Growth scenarios are presented in Table 5.1 and show that the NPCC LOLE criterion is satisfied for both median and high demand forecast scenarios.

The results presented in Table 1.1 show that the NPCC LOLE criterion is satisfied for Median Demand Growth scenario. The NPCC criterion is satisfied for 2019 and 2020 with existing and planned resources, based on the existing outage plan. For 2021 and 2022, it will be necessary to reschedule outages and rely on EOPs to satisfy the NPCC criterion. In 2023, the use of up to 100 MW of tie benefits will be required to satisfy the criterion.

For the High Demand Growth scenario, the NPCC criterion is satisfied for 2019 with existing and planned resources. For 2020 to 2021, at most 1,300 MW of tie-benefits in addition to EOPs and outage rescheduling are required to meet the LOLE criterion. In 2023, additional use of tie benefits are required to meet the criterion.

Table 5.1 Annual LOLE Values, Median and High Demand Forecast

Scenario	EOPs	Outages Rescheduled	Tie Benefits (MW)	LOLE [days/year]				
				2019	2020	2021	2022	2023
Median	No	No	0	0.002	0.099	0.389	0.337	0.506
	Yes	No	0	-	-	0.133	0.115	0.159
	Yes	Yes	0	-	-	0.015	0.015	0.107
	Yes	Yes	100	-	-	-	-	0.087
High	No	No	0	0.003	0.423	2.491	3.884	9.941
	Yes	No	0	-	0.129	1.129	1.881	4.813
	Yes	Yes	0	-	0.110	0.308	0.716	4.345
	Yes	Yes	1,300	-	0.008	0.030	0.097	0.873
	Yes	Yes	3,050	-	-	-	-	0.095

5.2 Demand and Resource Uncertainties

As in any system adequacy forecast, there are inherent uncertainties related to demand and resources, which include changes to demand forecast drivers, adjustments to generation resource availability, conservation or demand response, import or tie benefits support. The IESO has various ways to mitigate these uncertainties.

Flexibility, cost, and environmental performance have been incorporated in Ontario`s plan to ensure that commitment decisions are made in a timely manner. The IESO possesses a range of options to address these capacity needs, including coordinating outages outside the peak load seasons or periods of potential capacity shortages, the potential for more conservation and demand response, the reliance of non-firm imports, and the ongoing development of a capacity market in Ontario to to ensure capacity can be acquired transparently and competitively through the market.

Every quarter, looking out 18 months into the future, the IESO assesses the near term adequacy and reliability of Ontario's system integrating the generator and transmission outage plans of market participants. Beginning in December 2018, the IESO will also assess and publish a 60 month view of resource adequacy every other quarter. Periods where outages result in inadequate resource levels are identified to generators and transmitters. If market participants do not reschedule outages to address identified adequacy concerns, the IESO may reject outages.

Beyond the 18 month horizon, the IESO completes annual 20 year planning assessments to identify needs well in advance. These assessments factor in a range of uncertainties and work is underway to formalize these outlooks into a public annual report beginning in 2019.

When required, Ontario can rely upon its neighbours to help meet its resource adequacy criterion. In the summer with all transmission elements in service the theoretical maximum capability for exports is up to 6,121 MW and for imports is up to 6,610 MW; in the winter the theoretical maximum capability for exports is 6,360 MW and for imports is 6,830 MW.

These values represent theoretical levels that could be achieved only with a substantial reduction in generation dispatch in the West and Niagara transmission zones. In practice, the generation dispatch required for high import levels would rarely, if ever, materialize. Therefore, at best, due to internal constraints in the Ontario transmission network in conjunction with external scheduling limitations, Ontario has an expected coincident import capability of approximately 5,200 MW.

The most recent NPCC Tie Benefits study indicates a range of estimated tie benefit potential of 4,414 MW to 4,703 MW. For this review, some amount of tie benefits were used to meet the criterion from 2020 onwards under High Demand Growth Scenario and for 2023 only in the Mediam Demand Growth Scenario.

5.3 Impact of Proposed Changes on Area Reliability

The IESO is working with stakeholders to develop a capacity auction for Ontario. This work is in the early stages and is intended as a new mechanism for meeting resource adequacy requirements in Ontario and would be implemented in time to meet incremental capacity needs as it arises in the future. The fundamental role of the incremental capacity auction is to ensure Ontario's resource adequacy needs are met. The high level vision of this auction is a long term and enduring market mechanism that will be the primary tool to maintain resource adequacy with clearly defined market rules and governance structure. This mechanism will incentivitize capacity only by running an annual base auction, with seasonal obligations for an annual commitment period. The first auction is currently targeted to be in 2023 for a commitment period beginning in 2024.

5.4 Resource Adequacy Studies Conducted Since Last Area Review

In addition to the Interim Revivews of Resource Adequacy that were submitted in 2016 and 2017, the IESO conducts several other studies of resource adequacy.

The 18-Month Outlook presents the IESO's assessment of the reliability of the Ontario electricity system over the short term. This quarterly publication identifies whether the existing and proposed generation and transmission facilities are adequate to meet Ontario's needs over the next 18-months.

The Ontario Reserve Margin Requirements (ORMR) study is released annually. The IESO communicates Ontario's planning reserve margin requirements over the next five years to reliably supply the province's forecast demand, as required by the Section 8.2 of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC). The reserve margin requirement in any year is the amount of supply resources in excess of the annual peak demand needed to meet the NPCC reliability criterion of an annual loss of load expectation (LOLE) of 0.1 days/year. It is expressed as a percentage of annual peak demand.

The Ontario Planning Outlook (OPO), published every three years, is a technical report that provides a 20-year outlook describing the adequacy and reliability of Ontario's electricity system. The Ontario Planning Outlook provides planning context for policy makers and industry stakeholders. The most recent OPO was published in September 2016. Beginning in 2019, the IESO will be publishing updated reliability outlooks that identify capacity needs on an annual basis.

5.5 Reliability Impacts Due to Environmental Regulations and Fuel Supply Issues

Environmental Regulations

Concerns about the emission of greenhouse gases and other pollutants from coal-fired electricity production led to the provincial decision to phase-out all coal-fired units in Ontario. The last coal-fired generation was shut down in 2014, and Ontario is now free from all coal generation.

Since that time, other environmental initiatives included the Cap and Trade program, which began on January 1, 2017 and officially ended in Ontario in July 2018. It is expected that the federal carbon pricing backstop will most likely be in place in Ontario on January 1, 2019. An industry benchmark will be applied to the electricity sector; it 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. Therefore, the impact on resource adequacy is considered low and no further reductions in the on-peak capability of gas generation are simulated for this study to account for environmental regulation risks.

For known environmental regulations or issues, generators provide to the IESO their expected seasonal derates and these are modelled in MARS (e.g. cooling water temperature)

Fuel Supply and Transportation Considerations

Ontario is well situated with respect to natural gas transmission and storage. Based on the input received from stakeholders, the review of the winter operations conducted by the IESO as part of Ontario's Gas-Electric Coordination Enhancements initiative, and the assessment results of the Eastern Interconnection Planning Collaborative (EIPC) Gas-Electric System Interface Study, the IESO has concluded that Ontario's ability to meet the additional gas supply requirements in the period covered by this review is adequate, and that risk of interruption of gas supply is within acceptable risk tolerance. This study looked forward to winter 2023 to identify risks on the gas-electric system interface; the modeling assumptions used in 2023 for the EIPC study align with the gas generation assumptions in this Comprehensive Review (i.e. the in-service and out-of-service dates for gas generators are the same and there have been minimal changes to the ratings and forced outage rates for the gas fleet since 2015). The EIPC study found that the natural gas supply is favourable relative to other PPAs in terms of portfolio diversity and conventional storage deliverability. In addition, firm transportation entitlements and direct pipeline connectivity are also favourable relative to other PPAs.

The study reflects a few notable characteristics of Ontario's natural gas supply:

- Over 30% of Ontario's gas-fired power generation is located within the Dawn Storage Hub[4], which provides adequate storage capacity for Ontario's winters with robust access to US NE gas supply. Generators in the Union Southwest Delivery Area also have access to a season's worth of gas from this hub. Generators in other parts of the province can also access storage at Dawn.
- In addition to Dawn, Ontario is also supplied by the TCPL mainline. Generators in parts of northern and eastern Ontario can maintain firm transportation to Empress, Alberta. These generators make up approximately 30% of the Ontario's gas-fired generation, including Lennox GS which provides 2,100 MW has dual-fuel gas/oil capability.
- Many generators north and east of Kirkwall, that cannot maintain firm transportation to Empress, are incented in their contracts to maintain firm transport to the Dawn Storage Hub.

Therefore, the impact on resource adequacy is considered low and no further reductions in the on-peak capability of gas generation are simulated for this study to account for fuel supply and transportation risks.

5.6 Mitigation Measures for Environmental Regulations and Fuel Supply Issues

As described in Section 5.5, the reliability impacts of environmental regulations and fuel supply issues are both low. As a result, no mitigation measures were simulated for this study. To mitigate fuel supply issues, Ontario's generation includes dual fuel capability at one facility which accounts for about 20% of the gas-fired generation fleet. This generator maintains sufficient oil supply on site in winter for over a week of operation.

- End of Section -

[4]More information on the Dawn Storage Hub is available at: https://www.uniongas.com/storage-and-transportation/about-dawn

APPENDIX A: DESCRIPTION OF RESOURCE RELIABILITY MODEL

A.1 MARS Program

For the purposes of this study, the IESO used the Multi-Area Reliability Simulation (MARS) program. The MARS program is capable of performing the reliability assessment of a generation system composed of a number of interconnected areas and/or zones that can be grouped into pools.

A sequential Monte Carlo simulation forms the basis for MARS. In this simulation, a chronological system evolution is developed by combining randomly generated operating states for the generating units with inter-zone transfer limits and hourly chronological loads. Consequently, the system can be modelled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules that govern system operation. Various measures of reliability can be reported using MARS, including the Loss of Load Expectation for various time frames. The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for various reliability indices. These values can be calculated both with and without load forecast uncertainty. The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates LOLE values and can estimate the expected number of times various emergency operating procedures would be implemented in each zone and pool.

The first step in calculating the reliability indices is to compute the zone margins on an isolated basis for each hour, by subtracting the load for the hour from the total available capacity in the hour. If a zone is at a positive or zero margin, it has sufficient capacity to meet its load. If the zone margin is negative, the load exceeds the capacity available to serve it, and the zone is in a potential loss-of-load situation. If there are any zones that have negative margins after the isolated zone margins are adjusted for curtailable contracts, the program attempts to satisfy these deficiencies with capacity from zones that have positive margins. There are two ways for determining how the reserves from zones with excess capacity are allocated among the zones that are deficient. In the first approach, the user specifies the priority order in which deficient zones receive assistance from zones with excess resources. The second method shares the available excess resources among deficient zones in proportion to the size of their shortfalls. Priorities within pools, as well as among pools, can also be modelled. The IESO uses the first approach.

A.2 Load Model

The IESO uses a multivariate econometric model to produce the electricity demand forecast. The forecast is composed of hourly demand for Ontario and its 10 zones. The model uses three broad sets of forecast drivers: calendar variables, weather effects and economic and demographic variables. The forecast also accounts for conservation, price impacts and embedded generation.

Weather is represented by a Monthly Normal weather scenario which uses the last 31 years of historical weather data to generate typical or average monthly weather. This approach results in a monthly peak demand with a 50/50 probability of being exceeded. This methodology is in lieu of using a base year to scale the forecast demand shape. A measure of uncertainty in demand due to weather variability is used in conjunction with the Normal weather scenario to generate a distribution of possible demand outcomes. In the MARS program, demand is modelled as an hourly profile for each day of each year of the study period. An allowance for load forecast uncertainty (LFU) is also modelled.

LFU arises due to variability in the weather conditions that drive future demand levels. LFU is modelled in MARS through the use of probability distributions. These distributions are derived from observed historical variation in weather conditions that are known to affect demand including temperature, humidity, wind speed and cloud cover. Province-wide LFU distributions are developed for every month of the year and applied to all 10 transmission zones.

The economic drivers are generated using a consensus of publicly available provincial forecasts, along with economic forecasts from service providers. Demographic projections are publicly available from the Ontario's Ministry of Finance.

Conservation impacts are incorporated into both the demand history and forecast where the final demand forecast is reduced to account for those conservation savings. The conservation assumptions, incremental to 2018, as per the the 2017 Long Term Energy Plan, are provided in Table A.1.

Table A.1 Conservation Assumptions

Year	Conservation (MW)
2019	288
2020	482
2021	511
2022	523
2023	556

The demand forecast accounts for the impacts of embedded generation. Capacity projections based on projected generation are combined with historical production functions to generate estimated hourly output. This information is then applied to the demand forecast to determine the need for grid-supplied electricity.[5]

A.3 Demand Side Resources

There are two main demand management mechanism at the IESO that are modelled as resources: Demand Response (DR) and Dispatchable Loads. Demand Response capacity is procured through an annual DR auction. Resources with capacity obligation are required to be available for curtailment up to their secured capacity during times of system need. The former Capacity Based Demand Response (CBDR) program ends as of October 2018. Procured capacity under this program has successfully transitioned to the DR auction. We do not include programs that are providing ancillary services for adequacy assessment purposes. Dispatchable Loads are loads that bid into the market and are dispatched economically like other resources without participating in the Demand Response Auction.

Table A.2 Demand-Side Management Assumptions

	Summer		Winter	
Year	Gross Demand Management (MW)	Effective Demand Management (MW)	Gross Demand Management (MW)	Effective Demand Management (MW)
2019	857	533	998	793
2020	857	533	998	793
2021	857	533	998	793
2022	857	533	998	793
2023	857	533	998	793

The IESO treats DR as a resource. As such, to maintain consistency, the impacts of DR programs are added back to the historical data when forecasting demand. Effective values of DR programs are used in MARS to reflect dependable capacity.

Effective capacity available from Dispatchable Loads is determined based on historical capacity offered, using five-year history, by the participants during peak demand hours. In MARS, Dispatchable Loads are modelled as EOPs that are available at all times and are represented as monthly values aggregated for each transmission zone.

[5] More details on load modelling are described in the IESO document titled "Methodology to Perform Long Term Assessments" (http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/methodology_rtaa_2018jun.pdf?la=en).

Effective capacity for DR is determined based on historical performance of the participants of individual programs. In MARS, DR is modelled as EOPs that are available at all times and are represented as monthly values aggregated for each transmission zone.

Price impacts from time-of-use rates and critical peak pricing programs are treated as load modifiers and decremented from the forecast. In Ontario, some participants of demand measure programs also participate in a critical peak pricing program. Therefore, at the time of the annual peak, the demand forecast is reduced for the peak pricing impacts but, concurrently, the total available demand response capacity is decremented to ensure that the contribution of these resources is not counted twice.

A.4 Supply-Side Resource Representation

The aggregated installed capacity values as of August 2018 for all generating units expected to be participating in the IESO markets during the assessment period are shown in Table A.3. These values do not include generators that operate within local distribution service areas, except for those that participate in the IESO-administered market.

Table A.3 Existing Installed Generation Capacity, as of August 2018

Fuel Type	Total Installed Capacity (MW)	Number of Stations
Nuclear	13,009	5
Gas/Oil	10,277	31
Hydroelectric	8,472	74
Wind	4,412	38
Biofuel	495	9
Solar	380	8
Total	**37,044**	**165**

A.4.1 Resource Ratings

Definitions

The ratings of resources were based the ratings methodologies specified in the *IESO Methodology to Performa Long Term Assessments*. Summaries of the methodology for each resource type are provided below.

Thermal Resources

Four resource types are modelled as thermal resources: nuclear, gas, oil and biofuel. The capacity values for each unit are modelled on a monthly granularity, to capture external factors such as ambient temperature and humidity or cooling water temperature. For nuclear generators and the like whose MCR is not ambient temperature sensitive, the IESO models the genator's expected monthly gross MCR and their station service load (as submitted annually by the generator). Fossil- or biofuel-fired generators whose MCR is sensitive to ambient temperature provide gross MCR at five different temperatures specified by the IESO which are used to construct a temperature derating curve. For each such generator, monthly gross MCR values calculated at normal monthly temperatures using the derating curve.

Hydroelectric Resources

Hydroelectric resources are modelled in MARS as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity and monthly energy values are determined on an aggregated basis for each transmission zone. Maximum capacity values are based on historical median monthly production and contribution to operating reserve at the time of system weekday peaks. Minimum capacity values are based on the bottom 25^{th} percentile of historical production during hours ending one through five for each month. Monthly energy values are based on historical monthly median energy production since market opening.

For new hydroelectric projects, the maximum capacity value, the minimum capacity value and the monthly energy value are calculated using the methodology described above based on the historical production data of other generators in the zone where the new project is located.

Wind Resources

Wind resources are modelled probabilistically on a zonal basis as Type 1 Energy-Limited Resources with a cumulative probability density function (CPDF). In order to derive the CPDFs, first, the top five demand hour window by month for each shoulder period month and by season for summer and winter periods are determined based on five-year historical demand data. Historical wind production during these top five demand hours is then extracted to generate CPDFs. Seasonal CPDFs for the summer and winter, and separate monthly CPDFs for the shoulder months are modelled in MARS to represent the capacity contribution of wind resources to the system.

Solar Resources

Solar resources are modelled as load modifiers in MARS with production (MW contribution) calculated from projected installed capacities and hourly solar contribution factors. Hourly solar contribution factors are determined using 10 years of historical simulated data by calculating the hourly average solar contribution by month for each shoulder period month and by season for summer and winter periods. This methodology results in a 24-hour capacity factor that is used to create an hourly solar profile to modify load.

Criteria for Verifying Ratings

The Ontario Market Rules (*Market Rules Chapter 4, Section 5***)** require that all generators connected to the IESO-controlled grid test their equipment to ensure compliance with all applicable reliability standards, including NPCC Directory #9 "Verification of Generator Gross and Net Real Power Capability" and Directory #10 "Verification of Generator Gross and Net Reactive Power Capability."

Generators communicate to the IESO any changes to their units' verified gross and net MW capabilities as part of the Outage Management Process and the Facility Registration, Maintenance and De-registration Process, as described in *Market Manual 7.3 "Outage Management"* and *Market Manual 1.2 "Facility Registration, Maintenance and De-registration."*

Permanent changes to equipment that affect the MW output capabilities of generating units are communicated and assessed through the Connection Assessments process described in *Market Manual 2.10 "Connection Assessment and Approval Procedure."*

Generators provide to the IESO at least annually, the declared Maximum Continuous Rating at five temperature points for resources sensitive to ambient temperatures, as described in *Market Manual 2.8 "Reliability Assessments Information Requirements."* The IESO then determines the seasonal net MW values for these units consistent with the ambient temperatures assumed for each month's normal weather demand forecast. For generators that are not sensitive to ambient temperatures, generators provide their monthly Maximum Continous Rating, reflective of expected deratings due to external factors such as cooling water temperature.

The Market Rules (*Market Rules Chapter 4, Section 5.2)* also authorise the IESO to test any generation facility connected to the IESO-controlled grid to determine whether such facility complies with the applicable reliability standards.

A.4.2 Unavailability Factors

Unavailability Factors Represented and Source

For hydroelectric, wind and solar resources, forced outages, planned outages, and maintenance outages are inherently incorporated in the historical production data and/or capacity factors used in the reliability assessment. Fleet wide data are used for each fuel type to determine a coincident history, that is scaled to incorporate both existing and planned units. Planned and forced outage impacts for hydro, wind and solar are assumed to be already accommodated in the capacity assumptions used.

For thermal resources, planned and maintenance outages are explicitly modelled, using outage submissions from market participants. Sensitivity studies are performed for keeping planned outages 'as is' vs. moving them for when reliance on tie-benefits was needed. Equivalent Demand Forced Outage Rates ($EFOR_d$) for existing units are derived using rolling five-year history of actual forced outages. The derived $EFOR_d$'s are then converted to capacity state and transition rate matrices for MARS. For units with insufficient historical data and for new units, $EFOR_d$'s of existing units with similar size and technical characteristics are utilized to model the forced outage rates.

Maturity Considerations

Immature units are assigned an $EFOR_d$ based on the youngest facility with the same technology type and size. IESO uses the contracted commercial operation date to forecast in-service dates as a conservative estimate of the latest allowable in service date.

Tabulation of Typical Unavailability Factors

The projected $EFOR_d$ values in the form of weighted average and range by fuel type are provided in Table A.4. Table A.5 shows the typical unavailability factor for each fuel type at the time of summer and winter peak.

Table A.4 Ontario Projected Equivalent Demand Forced Outage Rates

Fuel Type	Weighted Average $EFOR_d$	Range of $EFOR_d$
Nuclear	6.7%	2.2 – 10.9 %
Gas/Oil	10.6%	1.6 – 26.7%
Biomass	8.4%	2.3 - 10.8%

Table A.5 Unavailability Factors

Fuel Type	Summer Unavailability Factor	Winter Unavailability Factor
Hydroelectric	32.1%	27.1%
Wind	87.4%	62.2%
Solar	89.9%	100%

A.4.3 Purchase and Sale of Capacity

As part of the Amended and Restated Capacity Sharing Agreement between Ontario and Quebec, signed November 2016, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023. As a result of the previous agreement, Quebec will provide Ontario a total of 500 MW of capacity in the summer months (June to September) to be exercised, when needed, any time before September 30, 2030. This capacity may be used once or be split into multiple summer periods, but cannot exceed 500 MW in total (e.g. 100 MW may be used in one year and 400 MW in another year). This summer capacity was relied upon in this Comprehensive Review in 2023 for both Median and High Demand Growth scenarios.

A.4.4 Retirements

The IESO estimate of future retirements is based on information provided annually by Market Participants to the IESO. While IESO's planning process considers conditions where facilities retire at the end of their contract period, for this review, the only estimated retirements are those facilities whose contract expire and the facility itself has reported to the IESO that they do not plan to continue operation after the expiry of the contract. In this assessment, it is expected that up to 1,405 MW of capacity will reach end of life or current contractual obligations by the end of 2023, of which 1,030 MW arise from the retirement of two nuclear units at the Pickering Nuclear Generating Station at the end of 2022.

A.5 Transmission System

A.5.1 Representation of Interconnected Systems

There are five systems with which the Ontario system is interconnected: Manitoba, Minnesota, Michigan, New York and Quebec. To model import assistance, an EOP is triggered in each Ontario zone that has an interconnection. The amount of EOP in each of the zones is based on the transfer capabilities of the interconnection.

To model the firm contract of 500MW with Quebec, Quebec is created in MARS with a transmission line interface to Ottawa. This transmission line interface is limited to a maximum transfer capability of 500 MW. To model conservatively, over the winter months (December to March) a 500 MW load in Quebec is used to represent Ontario's firm capacity export contract.

As part of the agreement with Quebec, Quebec will provide Ontario a total of 500 MW of capacity in the summer to be exercised, when needed, any time before September 30, 2030. This capacity may be used once or be split into multiple four month summer periods, but cannot exceed 500 MW in total (e.g. 100 MW may be used in one year and 400 MW in another year). The import is modelled in MARS as a 500 MW EOP in the Ottawa zone from June to September 2023.

The 2015 NPCC CP-8 study entitled "Review of Interconnection Assistance Reliability Benefits," published in December 2015 assessed that approximately 4,414 MW of interconnection assistance is reasonably available to the Ontario system by 2020. The expected capacity values used in this study vary, depending on Ontario needs, but are always subject to the limitations of the transmission interconnections outlined in Table A.6. Limits apply year-round except where seasonal ratings are indicated.

Table A.6 Ontario Interconnection Limits

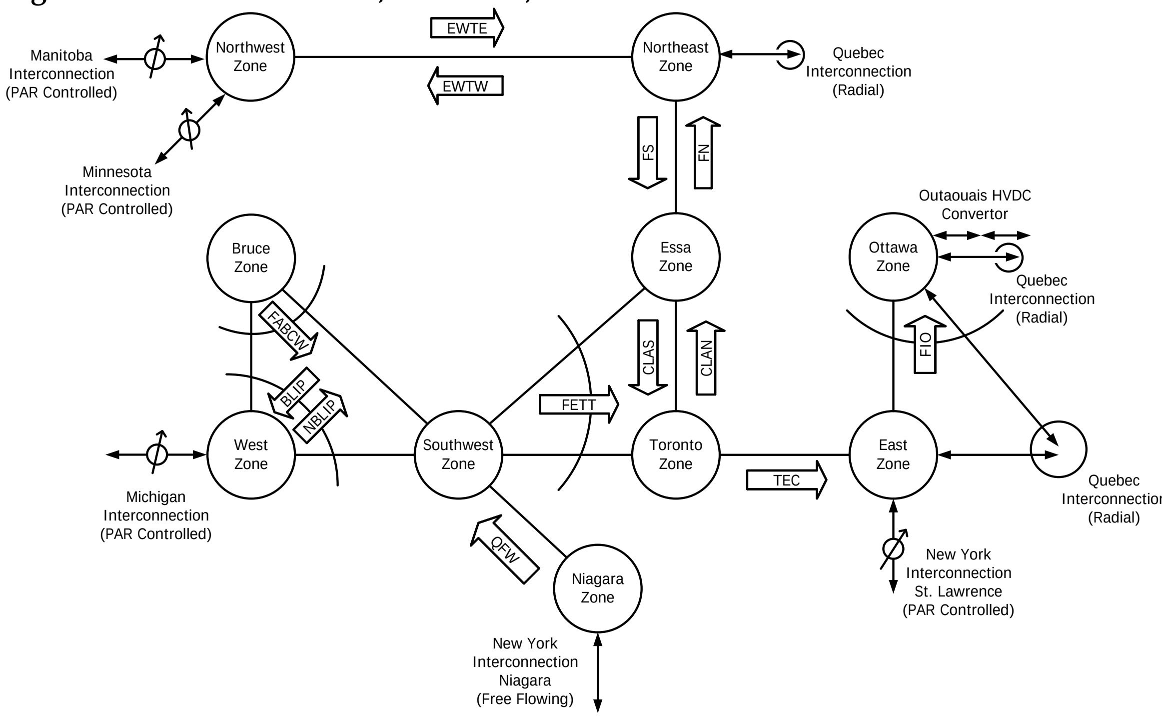
Interconnection	Limit - Flows Out of Ontario (MW)	Limit - Flows Into Ontario (MW)
Manitoba – Summer*	**225** (3)	**293** (3,5)
Manitoba – Winter*	**300** (3)	**368** (3,5)
Minnesota	**150**	**100** (3)
Québec North (Northeast) –	**95**	**65**
D4Z	0 (4)	65
H4Z	95 (4)	0
Québec North (Northeast)–	**110**	**85**
D4Z	0	85
H4Z	110	0
Québec South (Ottawa) –	**1,570**	**1,865**
X2Y	0	65
Q4C	120	not of
P33C	0	300
D5A	200	250
H9A	0	0
HVDC	1,250	1,250
Québec South (Ottawa) –	**1,590**	**1,865**
X2Y	0	65
Q4C	140	not of
P33C	0	300
D5A	200	250
H9A	0	0
HVDC	1,250	1,250
Québec South (East) – Summer*	**470**	**800**
B31L + B5D	470	800
Québec South (East) – Winter*	**470**	**800**
B31L + B5D	470	800
New York St. Lawrence –	**300**	**300**
New York St. Lawrence –	**300**	**300**
New York Niagara – Summer*	**1,650** (1)	**1,500** (1,6)
Emergency Transfer Limit-	**2,160** (1)	**1,860** (1,6)
New York Niagara – Winter*	**1,800** (1)	**1,650** (1,6)
Emergency Transfer Limit-	**2,200** (1)	**2,200** (1,6)
Michigan – Summer*	**1,700** (2,3)	**1,700** (2,3)
Emergency Transfer Limit-	**2,250** (2,3)	**2,250** (2,3)
Michigan – Winter*	**1,750** (2,3)	**1,750** (2,3)
Emergency Transfer Limit-	**2,350** (2,3)	**2,350** (2,3)

* Summer Limits apply from May 1 to October 31. Winter Limits apply from November 1 to April 30.
(1) Flow limits depend on generation dispatch outside Ontario.
(2) Normal limits are based on LTE ratings and Emergency limits are based on STE ratings.
(3) For real time operation of the interconnection, limits are based on ambient conditions.
(4) Limit based on 0 to 4 km/h wind speed and 30°C ambient temperature.
(5) Flows into Ontario include flows on circuit SK1.
(6) Flow limits into Ontario are shown without considering QFW transmission constraints within Ontario.

A.5.2 Internal Transmission Limitations

The Ontario transmission system is represented by 10 interconnected zones with transmission limits between the zones explicitly modelled. Figure A.1 provides a pictorial representation of Ontario's 10 zones. The limits modelled are the operating security limits (OSL) specified for each interface and any projected limit increase due to future transmission system enhancements is appropriately represented.

Figure A.1 Ontario's Zones, Interfaces, and Interconnections



Northwestern Ontario is connected to the rest of the province by the double-circuit, 230 kV East–West Tie. The primary type of generation within the northwest is hydroelectric. Additional capacity is required to maintain reliable supply to this area under the wide range of possible system conditions. The expansion of the East–West Tie with the addition of a new 230 kV double circuit transmission line is going to provide reliable long-term supply to the Northwest. The line is anticipated to be in-service in December 2020.

A.6 Modelling of Variable and Limited Energy Sources

Modelling of Variable Energy Sources were described in Section A.4 (Solar and Wind Resources). Hydroelectric resources are treated as limited energy sources as described in Section A.4 (Hydroelectric Resources). Ontario also has a biomass facility whose contract specifies its annual fuel requirement. It is treated as a limited energy source in MARS, with an annual limit of 140 GWh.

A.7 Modelling of Demand Side Resource and Demand Response Programs

Treatment of Demand Side Resources and Demand Response are described in Section A.3.

A.8 Modelling of All Resources

Treatment of in-service date uncertainty, capacity value and availability and were described Section A.4. Emergency assistance is described in Section 4.1. Scheduling and deliverability limitations of individual resources are considered as part of determining the monthly available capacity of the resource, where applicable. For example, by using coincident hydro production, deliverability to the grid is implicitly accounted for.

A.9 Reliability Impacts of Market Rules

No reliability impacts due to market rules are anticipated in this review. The IESO publishes expected changes to its Market Rules on an ongoing basis at http://www.ieso.ca/Sector-Participants/Change-Management/Pending-Changes-Documents.

- End of Document –

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TAB 19

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

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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

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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

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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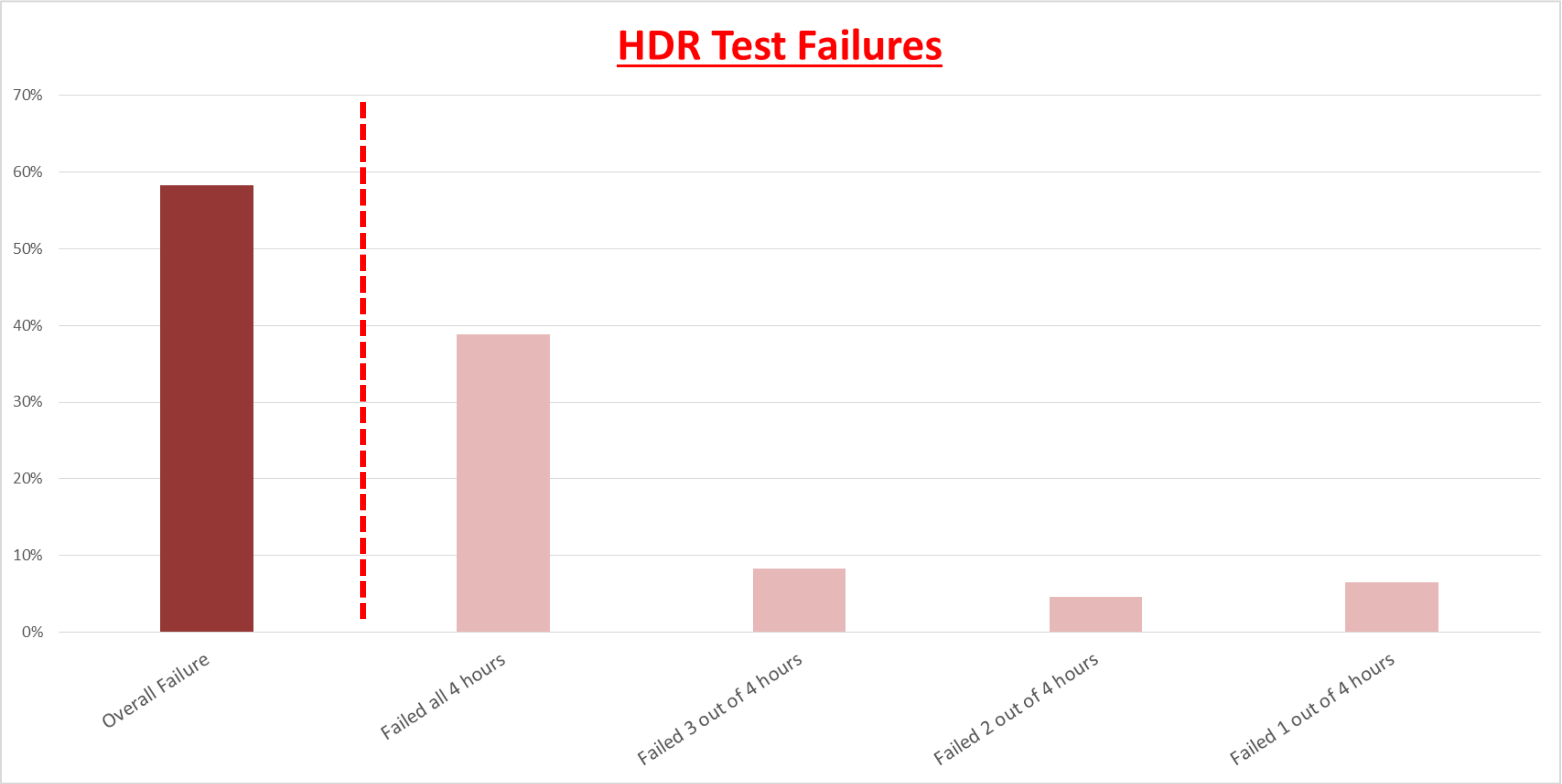
HDR Testing Performance



	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)

TAB 20

Notes for Remarks to the Ontario Energy Network Luncheon

January 28, 2019

Peter Gregg
President and CEO
Independent Electricity System Operator

Thanks very much for that kind introduction.

A year ago was my first opportunity to speak at this event … this came when I had been the IESO CEO for only six months. A lot has changed since then.

Externally of course the big change has been the change in government. Like many of you in this room, we have been working with the new government, briefing them on the issues and opportunities that are in front of us. And we have been working with them to implement some of their policy decisions. I had a chance to spend some time with Energy Minister Greg Rickford just last Friday at Bruce Power where we announced a $200 million savings through our contract with Bruce Power. It's a good example of the focus this sector is bringing to making electricity more affordable for Ontarians.

There has been a lot happening at the IESO as well. I want to give you a sense of what we have been up to for the past 12 months, outline our priorities for the next 12 months, and most importantly discuss how we can work together on those priorities.

A year ago I spoke to our continued commitment to serve customers at established reliability standards. I also spoke to the need to improve the efficiency of the markets and to ensure that we are enabling the changes of tomorrow.

There has been significant progress on those fronts …. progress that you will continue to see in 2019.

As I mentioned last year, my first six months at the IESO were spent talking to both employees and key stakeholders about the IESO. Our conversations focused on our many strengths and where I needed to focus my energies as the leader of this organization.

I quickly recognized that this was an organization of many strong parts, but one that lacked a singular, transparent focus. We were not clear on what our mandate was … which is not surprising in some respects given ongoing adjustments associated with the merger of the two predecessor organizations.

Over the past year, I have been working with our Board, the executive, senior leadership, other employees and some of our external stakeholders to help define our mandate, our value and our strategies to carry out our responsibilities.

At our core, we are the province's electricity grid operator and system planner. We ensure the reliability of Ontario's power system on behalf of all Ontarians.

We work with stakeholders, governments, Indigenous and other communities across the province to provide an efficient supply of electricity … when and where it's needed.

It's important to remember that we are a not-for-profit organization, with no financial stake in our industry, which enables our **independent decision-making … at the operational, executive and board levels.**

We recognize that these are huge responsibilities that we will honour. We have a focus on reliability and affordability and our strategy is to rely on competitive forces to secure resources and services that enhance reliability and drive down costs.

That focus on reliability and affordability has driven our actions over the past 12 months and will continue to guide us in the future.

To that end, we are once again seeking to hold our revenue requirements flat this year. If approved by the OEB, it will mean our 2019 fee will stay at the 2017 level.

But this doesn't mean we are doing less – importantly we are delivering on our mandate by being focused and disciplined.

Over the next few minutes I will outline some of our plans for 2019 … particularly in three areas – market renewal, cybersecurity and innovation.

Our key focus in 2019 will be the Market Renewal Program.

MRP represents the most important redesign of Ontario's electricity market since it opened 17 years ago. The need for and benefits of this redesign speak to our investment in this.

The markets that we are operating today are in need of significant updates. These reforms will allow us to accommodate the changes we have seen since market opening – changes in our resource fleet, changes in consumer behaviour and changes in how to use competitive approaches more effectively.

But it will also allow us to prepare for future changes as we welcome new market participants, new technologies and new approaches to meeting Ontario's electricity needs. New participants will result in increased competition which should drive costs down and ultimately lower rates for Ontario consumers.

As a result of our market renewal efforts, we are expecting to see savings of approximately $3.4 billion over a 10-year period … or an annual average of $340 million off of our annual electricity bill.

As you know, market renewal comprises two streams: energy, which is the actual production of electricity and capacity, which is having resources available to produce electricity when needed.

The energy stream initiatives improve upon our dispatch and pricing activities in real-time – programs that we have been executing since 2002. What was once a cutting-edge design is now older and has become less effective as the system transformed.

Both the OEB's Market Surveillance Panel and more recently the Auditor General have identified inefficiencies in our current mechanisms, inefficiencies that we need to address. In 2018, we produced three high-level designs for comment that will make significant enhancements to our current mechanisms … addressing the single schedule market, enhanced real-time unit commitment, and day-ahead market. We are starting to sift through the comments we receive and will incorporate these comments into our next iterations as we move to the detailed design phase.

Let me now turn to the capacity work stream. In March, we will also provide for public comment the high-level design for the incremental capacity auction. This is a major step forward for the program and for the IESO.

Over the years, Ontario and other jurisdictions have used different approaches to meet capacity needs. Most recently, Ontario has relied on a series of long-term contracts that generally provided some form of guaranteed annual revenue to generators for periods of 20 years or more.

This reliance on long term contracts did address our shortfalls through the addition of tens of thousands of megawatts; however, the lack of flexibility inherent in many of these contracts has led to higher costs for consumers.

This lack of flexibility shows up in a couple of ways:

- Our needs for capacity fluctuate from year to year. And while a long-term contracting approach is designed to address the largest capacity gap in any year, it can also lead to having more capacity than we need. As you know, Ontario has found itself with excess capacity now for some time;

- And as the system and our reliability needs evolve, we can adapt our market mechanisms to better align with system need. In contrast, contract changes can require lengthy negotiation to change terms.

The introduction of an incremental capacity auction at the end of 2022 is expected to drive significant benefits for Ontario … much of the $3.4 billion in savings that I spoke about comes from our future reliance on a capacity auction.

Capacity auctions provide the needed flexibility and allow us to more efficiently adjust to changing supply and demand dynamics. The auction will provide for more flexible, transparent, technology-neutral, competitive mechanisms to meet Ontario supply needs at lowest cost.

The development of a capacity auction is an example of our intended approach to rely on competitive mechanisms to secure future resources. And … in concert with the ICA … we are enhancing our long-term planning products to regularly and transparently identify Ontario's electricity needs. We have recently introduced a five-year reliability outlook that we are publishing twice a year.

As we ask suppliers to sharpen their pencils to participate in the auction, we at the IESO must ensure that these companies have access to the most current information about Ontario's electricity needs.

After more than a decade of intense capital investment, Ontario now has a clean and reliable electricity system. Over 93 per cent of the provincial supply last year was generated by non-emitting resources, such as nuclear, water and renewable sources like wind and solar.

Our development of the capacity auction is timely. Within the next few years, some of the longer-term generation contracts we have signed will start to expire. This will enable us to transition to using the ICA to secure required capacity, providing assurance that resources will continue to be available to meet demand in future years … albeit at a much better price.

This transition to a capacity auction will start to take shape later this year. As you know, in September we produced a new planning report which indicated a potential capacity gap emerging in 2023.

This gap would emerge at a time when Pickering units are closing, as nuclear refurbishments are underway and as some of our generation contracts expire.

While the forecasted gap is relatively small at the moment, our ability to continue to rely on existing resources such as conservation, could affect both the timing and the size of any potential gap.

Our Planning Group is now working to confirm that earlier assessment and we expect to have a clearer picture of our more immediate capacity needs in the third quarter of this year.

We will meet those capacity needs by leveraging the competitive mechanisms we have in place right now such as the annual demand response auction. We ran our first DR auction in 2015. Last month, in the fourth year of the auction, we acquired more than 800 MW of demand response for both the upcoming summer and winter commitment periods … at a price that was 43 per cent less than the first DR auction.

Not only are we seeing prices drop, but we are seeing increased participation in the DR auction. The successful proponents in last month's auction included four new participants representing both commercial and industrial demand resources.

In December, we will run an auction to meet capacity needs for 2020. Our goal is to have that auction and subsequent auctions build on the current demand response auction including allowing more resource types to compete. This would provide generators whose contracts are expiring over the next few years an opportunity to compete in our electricity market and help meet emerging capacity needs.

It is a staged approach to a much more competitive marketplace … one that we at the IESO and others are striving for. It allows us to realize efficiency, competition and transparency … the key principles of our market renewal efforts – as quickly as possible.

It's also a sensible approach, allowing both the IESO and market participants to continue to learn and improve our processes as capacity needs increase.

This staging will culminate in the implementation of the incremental capacity auction design that we have been developing with stakeholders. We expect to have that up and running by the end of 2022.

At the same time, there are more immediate needs in some parts of the province that we need to move quickly on.

One of those is in the Windsor-Essex area where we see a significant increase in demand looming. Over the next five years, current demand is expected to double. This is driven by strong agricultural growth in the greenhouse sector, both vegetable and cannabis. Take a drive along Highway 77 and you can see a lot of new greenhouses being built.

We have started working with the local community on how to best address that increase in demand. We see the need for new transmission infrastructure and again we are looking to see if competitive mechanisms can drive those costs down.

Let me switch gears for a moment and talk about something that has occupied quite a bit of my time … and that is being prepared to deal with the growing cybersecurity threats that are materializing.

The IESO's licence has been amended to reflect our expanded accountability for providing cybersecurity-related services to the broader electricity sector. With this change, the IESO becomes the first system operator in North America to lead the sector on cybersecurity matters.

It recognizes our leadership in protecting Ontario's power grid from cyber threats and leverages the comprehensive cybersecurity governance framework that we already have in place for our own operations.

In support of our new mandate, we have established partnerships with the Canadian Centre for Cyber Security. The Cyber Centre is the central trusted federal government source of cybersecurity information, advice and guidance for Canadian enterprises, critical infrastructure owners and operators and Canadians.

The IESO has also established a new Security Operations Centre. It went live at the end of 2018. This centre provides actionable information, in a near real-time capacity, 24/7 in order to improve incident detection and response capabilities across our sector.

Recognizing our leadership role, we are also working with all licensed transmitters and distributors to facilitate the sharing of centralized cybersecurity information. This includes bringing together our sector counterparts, as well as the world's leading cybersecurity policy experts to share best practices in addressing existing and emerging cybersecurity issues within Ontario's electricity sector

As part of our focus on cyber, I am joining the Electricity Subsector Coordinating Council as one of two Canadian members. The council acts as the liaison between the North American energy sector and federal governments to coordinate our efforts to prepare for national-level threats to our critical infrastructure.

As we look at the electricity sector since 2006, which is when I joined it, we have seen a continuous change. The way electricity is produced has changed significantly as has the way that we consume it.

All we have to do is look at the growth of distributed energy resources in the last decade or so.

DERs are helping to shape a more decentralized electricity system, changing the relationship between local distribution systems and broader transmission system. They are also providing more customer choice – through the IESO's regional planning process, some communities have expressed a preference for DERs to address regional demand growth or to replace aging assets. DERs may also present opportunities to optimize overall system investments and provide a range of grid services.

At the end of 2017, there were more than 3,880 MW of contracted embedded generation within local distribution systems, a 25 percent increase over 2016.

New technologies are coming at us quickly … and the potential of these new technologies and services is significant. But so is the risk that the adoption of these innovative approaches could undermine the reliability and affordability of our system.

Last year, working with an extensive group of stakeholders, the IESO developed an innovation road map. This road map, which is posted on our website, sets out a framework and focus for electricity sector innovation.

The priority areas of focus for the IESO include:

- Unlocking the value of new and existing resources;
- Leadership with respect to emerging cybersecurity risks;
- Increasing transparency and visibility of distributed resources; and
- Developing new capability to collect, store, analyze and use that data that comes with the operation of the power system.

I have talked already about our cybersecurity efforts. But this year will also see us focusing on distributed energy resources:

- Working with broader sector participants to help enable these DERs to compete in the IESO-administered markets;
- And developing several demonstration projects with others to understand the value and ability of DERs to address local needs as alternatives to traditional transmission and distribution infrastructure.

Storage is another priority for us this year. We will be working with the Energy Storage Advisory group to help enable storage to compete in our markets. This is in line with efforts of our U.S. system operators who are required by FERC to fully enable storage to compete to provide all energy, capacity and ancillary services by the end of 2019.

As we move forward with our 2019 plans, whether it's market renewal, addressing a potential capacity gap, addressing needs in a particular area of the province or helping to enable innovation … we can't do this alone.

The principle of collaboration … partnering with others to drive better outcomes … is one that we have embraced.

Our plans and activities benefit from our engagement, whether that's about rule changes, process changes or policy development.

However, in getting your advice and input we also need to be mindful of the time commitments that are involved in our engagements.

In 2017, more than 5,300 people attended one or more of our 120 engagement activities. And while that number certainly demonstrates inclusiveness, I would suggest it's a number that's not sustainable.

Our challenge this year is to better streamline our engagement activities … Creating the same opportunity to provide meaningful input but doing so in a way that reduces the time commitment of stakeholders.

There is no question that this sector will continue to evolve and there is uncertainty ahead of us.

But over the past decade we have become used to this uncertainty. Yes we need to get better at managing risk and embrace the changing environment that we are in.

But I challenge you to find another sector that has faced as much change as we have over the past decade or will over the next.

As you can tell, there is a lot on our plates for 2019. Over the past 18 months, we have been laying the foundation for some of our future plans. We have a clear mandate, a strategy on how we are achieving that mandate and a commitment to work with you and others.

Now is the time for us to get on with the execution of those plans.

I hope to come back next year and report on the progress that we collectively have made.

Thanks again for inviting me here today.

-30-

TAB 21

Demand Response Working Group – Meeting Notes

February 12, 2019

Meeting Notes

Dates held: February 12, 2019	**Time held**: 9:00am to 1:00pm	**Location**: Crowne Plaza, Toronto International Airport
Company	**Name**	**Attendance Status** (A) Attended; (WebEx) Attended via WebEx
Alectra Utilities	DeJulio, Gia	A
AMPCO	Forsyth, David	Webex
AMP Energy	Luukkonen, Paul	A
Bruce Power	Zhang, Alvin	A
Cascades	Ross, Josh	Webex
CGI	Graham Hughes	Webex
City of Toronto	Cheng, Jessie	Webex
City of Toronto	Gu, Michael	A
City of Toronto	Koff, Chaim	A
City of Toronto	Poto, Angelo	A
Customized Energy Solutions	Withrow, David	Webex
Direct Energy	Cavan, Peter	Webex
Direct Energy	Clicker, Owen	Webex
Direct Energy	Galarneau, Kenneth	Webex
Ecobee	MacCaull, Aira	Webex
Electra	Carr, Daniel	Webex
Enel X	Chibani, Yanis	Webex
Enel X	Griffiths, Sarah	A
Great Circle Solar Mgmt Corp	Antic, Tina	Webex
Great Circle Solar Mgmt Corp	Macabales, Deonnie	Webex
Great Circle Solar Mgmt Corp	Wharton, Karen	Webex
HCE Energy	Michael Crown	Webex
Hydro One Network	Katsuras, George	Webex
Ivaco Rolling Mills	Abdelnour, Francois	A
Ministry of Energy, Northern Development and Mines	Tomlinson, Patrick	Webex
Nest/Stem	Amaral, Utilia	A
Independent Consultant	Coulbeck, Rob	A
Northland Power	Samant, Sushil	A
Northland Power	Swan, Darrell	A
Northland Power	Windsor, John	A
Northland Power	Zajmalowski, Mike	A
NRG Curtailment Solutions, Inc.	Popova, Julia	Webex
NRG Curtailment Solutions, Inc.	Shelly, Christopher	A

Dates held: February 12, 2019	**Time held**: 9:00am to 1:00pm	**Location**: Crowne Plaza, Toronto International Airport
Company	**Name**	**Attendance Status**
NRG Curtailment Solutions, Inc.	Vukovic, Jennifer	Webex
Ontario Energy Board	Holder, Ryan	A
Ontario Power Generation	Kim, Jin	A
Ontario Power Generation	Urukov, Vlad	Webex
Power Advisory	Lusney, Travis	A
Power Advisory	Simmons, Sarah	A
Shell Canada	Lasik, Phil	Webex
Resolute Forest Products	Degelman, Cara	Webex
Resolute Forest Products	Ruberto, Tony	A
Resolute Forest Products	Giardetti, Peter	A
Rodan Energy Solutions	Goddard, Rick	A
Rodan Energy Solutions	Nathwani, Rahi	Webex
Rodan Energy Solutions	Row, William	Webex
Rodan Energy Solutions	Stewart, Blaire	Webex
Rodan Energy Solutions	Holowatsky, Yuri	Webex
Sinopa Energy	Collins, Ron	Webex
Southcott Ventures	Lampe, Aaron	Webex
Sussex Strategies	Hiltz, Bonnie	Webex
Toronto Hydro	Marzoughi, Rei	Webex
TransCanada	Kuntz, Margaret	Webex
Rayonier Advanced Materials	Laflamme, Serge	A
Union Gas	Dent, Dave	Webex
Voltus	Grav, Jorgen	Webex
IESO	Campbell, Alexandra	A
IESO	Gojmerac, Mark	A
IESO	Nusbaum, Stephen	A
IESO	Rashid, Fahad	A
IESO	Savage, Jessica	A
IESO	Short, David	A
IESO	Singh, Diljeet	A
IESO	Versteeg, Peter	A
IESO	Young, Jennifer	A
IESO	Yung, Ambrose	A
IESO	Zaworski, Richard	A
Prepared by Peter Versteeg, please report any corrections, additions or deletions by e-mail to engagement@ieso.ca		

All meeting materials are available on the IESO web site at: http://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Working-Groups/Demand-Response-Working-Group

Introduction – Jennifer Young, IESO

The IESO welcomed participants and described the format of the meeting.

Demand Response (DR) Testing Update – Ambrose Yung, IESO

The IESO led stakeholders through an update of the proposed changes to the Test Activation Protocol, a review of Test Activation Duration, as well as Market Manual updates of DR Enhancements coming in May.

A participant asked if the new Advisory Notice would be in the form of an email.

The IESO replied that the Advisory Notice will be available through the Online IESO Portal and the IESO website. Participants will continue to get a Standby Notification and an Activation Notification through email.

A participant asked if the Test Activation Duration of 4 hours only applies to Hourly Demand Response (HDR) resources and if Dispatchable Load (DL) is tested separately.

The IESO replied that the Test Activation Duration of 4 hours only applies to HDR resources. For DL it usually relies on data from in-market activations but will test DL directly if this is not available.

A participant asked if the Incremental Capacity Auction (ICA) Capacity Check Test will be more stringent than the DR Test Activation.

The IESO replied that the ICA will have a Capacity Qualification process that will measure resources on an Unforced Capacity basis and it will test for the full amount it expects to be available. There will not likely be a 20% dead-band as in the current DR test.

A participant asked what standard is being used to test HDR resources, such as an event 4-hour average or an hourly bright-line against a 15% dead-band, and what constitutes a "pass".

The IESO replied that it can provide statistics on the performance of previous years' HDR resources.

A participant asked if the Test Activation Duration applies to DLs participating in the HDR program as part of an aggregator portfolio.

The IESO replied that it would see these resources as HDR resources and this would apply to them.

A participant noted that the timing of these tests is not consistent with when system emergencies happen. The participant asked the IESO to consider a two-week window for the test similar to other markets.

The IESO replied that it will take this back for consideration.

Editor's note: the IESO is unlikely to adopt a two-week window for testing given the seasonal product being developed and the current approach to qualifying and settling resources.

Background on the DR Audit Provisions - Richard Zaworski, IESO

The IESO led stakeholders through a discussion on the context and background on the requirements for DR audit provisions.

DR Measurement Data Audit Process and Data Acquisition (Virtual – C&I) – Fahad Rashid, IESO

The IESO led stakeholders through a discussion on the DR Audit Process, Meter Data Submission, the IESO's response to DRWG feedback, and next steps.

A participant asked why all payments are subject to clawback in the case of an overpayment (Market Rule Chapter 9 - Section 4.8.3), but only the adjustment is due in the case of an underpayment (Market Rule Chapter 9 - Section 4.8.4).

The IESO replied that if the DRMP fails to submit data in a timely manner the Market Rules require the IESO to recover all payments as part of the recovery clause (Section 4.8.3). However, there are cases when a DRMP may have failed an activation, and realized that it had submitted incorrect data to the IESO. The DRMP has the opportunity to submit corrected data via Notice of Disagreement. In these cases, the IESO can make adjustments to the payment as part of the distribution clause (Section 4.8.4).

A participant noted that it would make the most sense for the Market Rules (Chapter 9 - Section 4.8.3/4.8.4) to be equal for both overpayments and underpayments.

The IESO noted this and thanked the participant for this suggestion.

A participant asked what the ratio is of physical load to virtual load in the HDR program.

The IESO replied that the majority of load in the HDR program is virtual.

A participant asked how material the issues found in the audit review were.

The IESO replied that in 2017 it conducted about 20 audits representing about $5M in availability payments handed out over the months audited. The failures observed were associated with roughly $3M of those availability payments.

A participant asked if the IESO has engaged with Local Distribution Companies (LDCs) to resolve the issues outside of a Demand Response Market Participants (DRMPs) control.

The IESO replied that while it has not yet engaged directly with LDCs it is reviewing the requirements internally and how they pertain to LDCs.

A participant asked if LDC statements are the only legal unit of measurement and why actual LDC interval data cannot be used. The timing of meter reads can cause a misalignment of data with LDC statements, but actual LDC interval data would resolve this.

The IESO replied that DRMPs can directly collect data from the meter or from LDCs. Under the existing audit program, IESO requires LDC statement whether the data is collected through the LDCs or directly from the meter. Meter data from an LDC may be deemed as data from a true source to determine the accuracy of actual measurement data. However, there is a need to establish provisions to enable this. In the audit, the IESO did not observe many issues in LDC statements but it can address these as needed.

A participant noted that there are high costs associated with acquiring LDC statements versus LDC interval data, and asked if there is a lower cost way to meet the IESOs data needs.

The IESO replied that it will review internally to see if LDC interval data can meet IESO requirements.

A participant noted that KYZ pulses were a common way of gathering data in Demand Response 3 and Capacity-Based Demand Response program installations. They are not explicitly mentioned in the rules but are not excluded either.

The IESO replied that the market manuals only mention two ways by which data can be collected. The first one is to directly access the meter and second one is to gather data through the LDC. There is no explicit mention of collecting data using KYZ pulses in the Market Manuals. However, past audits reveal that KYZ pulses have been used by the DRMPs to collect meter data.

A participant asked if data from a Measurement Canada meter would be acceptable to the IESO. DRMPs could then submit a Record of Installation (ROI) or an LDC statement.

The IESO replied that the DR Auction program does not allow data from meters not installed directly by the LDC, even if they are approved by Measurement Canada. Participants noted in the design of the Demand Response Auction (DRA) that a simplified process for contributor management and measurement data submission was needed. The metering requirements therefore focus on the use of an IESO or LDC revenue meter.

A participant noted that KYZ pulses are being phased out by many utilities and therefore additional metering will be a requirement.

The IESO replied that the requirements for record keeping on the DRMP will increase with additional metering compared to what is proposing under the current structure. The industry needs to look at what can be done to overcome barriers to access existing infrastructure.

A participant noted that they need to understand what constitutes a failure in the audit and that an audit should be limited to event months only. Punitive administration charges are being applied for non-event months even though resources are available because aggregators cannot match up data perfectly.

The IESO thanked the participant for their comments.

A participant noted that an issue in acquiring data from just 1MW of a resource that has a 20MW obligation and 25MW of registered load can cause more than a 1% error in the data, and under the current rules the entire resource could be valued at zero. One useful change to the program rules would be to submit data at the contributor level. This would provide more visibility to the IESO and an avenue for participants to prove their resources are still available if there are measurement data issues.

The IESO replied that it would take this proposal back for review.

A participant asked if the IESO requires LDC statements for physical contributors.

The IESO replied that it does not require LDC statements for physical contributors as physical contributors are registered in the wholesale market and subject to an audit process defined in the market rules for registered wholesale meters

A participant asked if the IESO intends to audit up to 7 years as publicly traded companies do not want the liability of a potential audit on the books this length of time.

The IESO replied that it does not intend to go back 7 years to audit, but it does want to make sure that this information is available if there is a need.

A participant asked for more information on the review of requirements for behind-the-meter storage as part of the DR program and if this will be discussed at the Energy Storage Advisory Group or the DRWG.

The IESO replied that it is looking at how requirements for behind-the-meter storage will impact the system and that it will discuss these at the DRWG and at other forums if needed.

A participant asked if load displacement methods such as behind-the-meter generation are included as part of the behind-the-meter energy storage review.

The IESO replied that participants specify at the time of registration whether load reduction or behind-the-meter generation will be used. Currently, behind-the-meter generation is not being reviewed as there are already requirements specified in the Market Manual for this.

A participant asked where behind-the-meter storage is being reviewed (ESAG, Market Renewal, DRWG, LDC engagements) and what the scope of that review is.

The IESO replied that it is currently in the process of reviewing behind-the-meter storage internally. IESO will share any information pertaining to this review at the appropriate engagement forums.

A participant noted that the need for LDC statements means that smaller resources such as a commercial store will be held to an IESO physical registration standard and this will prevent these resources from participating.

The IESO thanked the participant for their comments.

A participant noted that LDCs are only required to retain 18 months of data by the Ontario Energy Board for auditing purposes and the IESO should have similar requirements.

The IESO replied that it recognizes the disconnect in regulations for data retention. This is under review but currently the Market Rules require record retention for 7 years and processes and audit responsibilities are built around this requirement.

Day-Ahead Market (DAM) High Level Design (HLD) Considerations for Hourly Demand Response (HDR) Participation – Mark Gojmerac, IESO

The IESO led stakeholders through DAM HLD considerations and implications for HDR resource participation.

A participant asked if HDR resources are themselves market participants.

The IESO replied that HDR resources are DR market participants, the participation model distinguishes between energy market participants and DR market participants.

A participant noted that as Market Renewal progresses there should be a greater focus on LDC stakeholdering. Visibility at the distribution level and questions about responsibility, how LDC systems evolve, who requires revenue grade meters, and who is responsible for errors and omissions will all be important.

The IESO acknowledged the feedback and thanked the participant for the comment.

A participant noted a lack of consultation and decisions in the HLD about HDR participation in the DAM. The participant asked if further work on the DAM will be presented to the DRWG as DAM decisions will have a big impact on aggregators.

The IESO replied that the Engagement Plan for Detailed Design will provide clarity on which stakeholders should participate in which design discussions. Detailed design will outline the participation models for all resources including DR under the incremental capacity auction and renewed energy market.

A participant asked if a load with an energy or ancillary service position in the DAM would be exposed to uplift.

The IESO replied that uplift in the DAM will not be based on DA schedules but will continue to be allocated based on Real-Time load and export consumption in the Real-Time Market.

A participant asked if there will be any changes with respect to aggregation rules for DR resources across LDCs.

The IESO replied that aggregating across LDCs introduces some complications and is easier to integrate if appropriate metering is in place.

Market Rule Amendment Proposal Demand Response – Peter Giardetti, Resolute Forest Products

Resolute Forest Products (Resolute) led stakeholders through an overview of its Market Rule Amendment Proposal.

A participant asked if the generator was dispatched by the IESO or if this was self-generation.

Resolute replied that this is self-generation.

A participant asked if the net change in DR load issue would also occur at the distribution level.

Resolute replied that it is not sure.

Market Rule Amendment Proposal Demand Response – Alexandra Campbell, IESO

The IESO provided further context on predecessor programs, the current Demand Response Auction (DRA) program and the potential implications of the Resolute Proposal on the broader market.

A participant asked if the 25MW Resolute injects into the grid is paid based on the Hourly Ontario Energy Price.

Resolute replied that the generator is part of a power purchase agreement (PPA) which takes into account how much is being generated regardless of whether there is demand response.

A participant asked if the net change in DR load is 55MW when the newsreel is down with Resolute injecting 30MW back into the grid under a PPA.

Resolute replied that this is correct.

A participant asked if the IESO could be more specific about other configurations that may have a similar issue.

The IESO replied that there are many different ways that loads and generators could be configured and measured, and therefore this proposed rule change could have broader implications. This proposal could mean metering in one way for one program and metering in a different way for other programs and it is a concern for the IESO that participants could have different metering configurations depending on the program that they are in. This issue could have broader market implications as well.

A participant asked if the IESO had a specific configuration that it has an issue with.

The IESO replied that it has not done a detailed analysis but, as an example, a participant could end up not being a net injector depending on the size of the generator and the load. It is important to look at what a resource is able to contribute to the grid that allows the IESO to match supply and demand, and the IESO needs make sure that what it is paying for is actually providing value to the system.

A participant asked if the IESO agrees with the intent or interpretation of the rule and if it will propose a re-write.

The IESO replied that it needs to have a further understanding of the issue and its implications before it establishing a formal position on the proposed amendment.

A participant asked if there is anything in the Market Rules or Market Manuals about injection and withdraw channels.

The IESO replied that virtual resources with behind-the-meter generation to offset load will only get load reduction payments for the load that is offset, they will not be credited in DR for excess generation or injection. In the Resolute case, there are some questions about whether there is a load reduction or if generation is being injected into the grid for load reduction payments.

Resolute replied that the DR program is a response to an activation and they are not changing generation in this case. The DR revenue meter was installed in this configuration to make sure that there is not a change in generation to make it look like Resolute is reducing load. When activated, Resolute is shutting down the newsmill and reducing its load by 55MW.

A participant noted that this issue should be looked at not just as load reduction but as one that will impact the ICA as the capacity product can include generation and a reduction in load.

The IESO replied that if the load and generator were metered separately with the generator having a PPA it would not be able to participate in the ICA. The IESO would have to look at what happens when different metering situations apply for different programs.

A participant noted that the principals governing open access and competition on the distribution system should be discussed, as utilizing accessible data and managing distributed generation for the benefit of the ratepayer is important. There does not appear to be an agency taking responsibility for bringing these pieces together. The participant asked where the IESO sees that centralized vision and responsibility.

The IESO replied that it will take this back for consideration. It wants to make sure that it does not allow metering configurations to exist that do not provide the intended benefits to the electricity system.

A participant asked if a third meter directly in front of the newsmill would solve the problem.

The IESO replied that it may not, particularly if the newsmill was supplying demand response. Different metering configurations can lead to different measurements and the IESO would like to utilize only one meter to avoid this.

A participant asked Resolute if their electricity costs for the newsmill are based on 60MW during normal operation and only 5MW during DR activation.

Resolute replied that the PPA is confidential but the newsmill buys back the entire amount whether it is from the grid or from the generator.

A participant asked if the generator is metered on its own and if the IESO can see the data.

Resolute replied that there is a revenue grade meter on the generator.

A participant shared support for the proposed rule change and wanted to understand what issues the IESO has with it or to see a counter-proposal.

The IESO noted that the Technical Panel is asking for feedback on this Market Rule amendment proposal and asked participants to provide written submissions on this rule to rule.amendments@ieso.ca by February 21, 2019.

Expanding DR to Uncontracted (Stranded) Generators – John Windsor, Northland Power

Northland Power led stakeholders through a presentation and discussion on the value of expanding the Demand Response Auction to uncontracted generators and other potential capacity providers.

A participant had the following comments: 1) The DRA is a transition mechanism for load and more work is needed so loads can participate in the market, these priorities should not be shifted. 2) Since the IESO is opening up market mechanisms such as the DRA it should open up the OR market for loads. 3) The name of the DRA should change and rules and governance issues should be reviewed. 4) More transparency is needed on how the demand curve is created. 5) More meetings are needed to work out all these issues.

Northland replied that it is not suggesting that generation is DR but that both load and generation can meet a capacity requirement and the economics should determine who meets the demand.

A participant asked if the Kingston Cogen facility can provide energy, capacity, and ancillary services now as it does not need to participate in the DRA for these purposes.

Northland replied that Kingston needs a higher energy price to cover marginal costs. If a capacity program covered more fixed costs it would be able to better participate in energy and ancillary programs.

A participant noted that if the IESO opens up the DRA it should also open up products that DR can provide and utilization payments should be part of that discussion. Another participant expressed concerns about such a major change in the DRA given relatively short notice.

The IESO thanked participants for their comments.

Meeting Ontario's Capacity Needs After 2019 - David Short, IESO

The IESO led stakeholders though a discussion on the plan for evolving the DRA and meeting Ontario's capacity needs after 2019.

A participant noted that there was no stakeholdering in the decision to evolve the DRA.

The IESO replied that the IESO signaled that it was not going to sign additional contracts at the 2018 Technical Planning Conference and based on the forecast this is the time to make these changes.

A participant noted that the Technical Planning Conference focused on 2023 and changes for 2020 is ambitious. Engagement on this evolution need to start right away and has to include other opportunities for DR to create a level playing field.

The IESO replied that stakeholdering will follow the day after the ICA's HLD stakeholdering session and the evolved DR design will follow shortly after the release of the ICA HLD.

A participant asked if other opportunities for load, such as utilization payments for DR and Operating Reserve opportunities for HDR will be part of the discussion in evolving the DR.

The IESO replied that the focus on this new engagement will be on expanding the auction and it will have to determine separately how to manage DRWG issues. The IESO will clearly identify for stakeholders where each of these issues will be covered.

A participant stated that it is problematic for the IESO to pick and choose which revenue opportunities to provide for different resources. Opening up the DRA to generators for a DR capacity payment but not the ancillary services market or utilization payments for DR is an example of this.

A participant asked if it would legitimize the proposed amendment if the DRA was open to generators and Resolute did not have a PPA.

The IESO replied that it will have to look at this in more detail.

A participant asked if a market participant providing capacity in the ICA or the evolved DRA would get compensated equally whether it is generation or a reduction in consumption.

The IESO replied that if there is a mix of generation and DR the IESO would have to look into that.

A participant asked why DR and behind-the-meter generators would not be compensated the same for providing the same capacity product.

The IESO replied that they would be compensated the same, although the way in which we perform the initial upfront capacity qualification process may be different.

A participant asked if the price per MW of capacity will be the same.

The IESO replied that the price per MW is the same but assessment, measurement, and delivery will vary for different resources.

A participant noted that net generation is precluded under the DRA rules and asked how a resource that can both inject and displace load would not get compensated for these services.

The IESO replied that it will take this back for consideration. There are different rules for different resource types and currently the IESO cannot accommodate a resource that injects and withdraws. It has been working to create a level playing field in developing the ICA.

A participant noted that if generators are compensated in the DRA, behind-the-meter generation should be compensated as well.

The IESO replied that it will take this back for consideration.

A participant asked if the IESO considers DR to be competitive with other resources noting that updates to Market Rules, and Market Manuals need to be completed for DR to compete from a financial perspective.

The IESO replied that in other jurisdictions the capacity auction is a good opportunity for DR. It helps keep the market liquid and competitive and this is what it hopes for in Ontario. Making sure DR is as viable as any other capacity product is part of the DR work plan discussion.

A participant asked if there would be a new DR work plan or stakeholdering session to discuss the evolution of the DRA.

The IESO replied that a new engagement will discuss how to evolve the auction, and the 2019 DR work plan will be a separate engagement. The DR work plan is still open for comment and will guide the DRWG over the next few years.

Update to the 2019 DR Work Plan – Alexandra Campbell, IESO

IESO led stakeholders though a discussion on the 2019 DR work plan.

A participant asked if the IESO could release a Target Capacity for the 2019 TCA earlier in the year.

The IESO replied that it does not have an answer to this yet. The engagement on the transition from the DR auction will discuss the process to determine Target Capacity.

A participant asked if the capacity associated with the 2019 TCA will be known before the IESO provides the Q3 plan on post-2020 capacity needs.

The IESO replied that it will work to be more specific on dates over the next 6 months and it recognizes that the Target Capacity is a key component to a healthy market. It will post the Target Capacity in the Pre-Auction Report at the end of September or beginning of October.

A participant noted that enabling DR through participation in other markets such as OR should be the highest priority item on the DR work plan.

The IESO thanked the participant for their comments.

A participant asked how the Market Rule Amendment Proposal should be addressed now that the DRA will evolve.

The IESO replied that it will have to take this back for consideration as there should be more analysis on the proposal in the context of the evolution of the DRA. It will note to the Technical Panel that the DRWG needs to explore this question further.

A participant asked if the Market Rule Amendment Proposal could be resolved by the December auction.

The IESO replied that rule language has been proposed and the Technical Panel is looking for broader stakeholder input. The IESO would have to have a final proposal to the IESO Board by August for any changes to occur for the December auction. The IESO will aim to have a follow-up discussion on this at the next DRWG meeting.

A participant asked how the DRWG should provide feedback to the Technical Panel.

The IESO replied that based on today's discussions it will go back to the Technical Panel and note the request for more information on IESO's position, and if this should be viewed differently given the DRA evolution. The Technical Panel has asked for feedback from stakeholders on the amendment submission and this too will factor into how they proceed with this amendment when they meet on March 5.

Resolute noted that it believes the rules are clear and that they are living up to the intent of the program. The amendment proposal intends to provide greater clarity and it is looking for a decision as soon as possible.

Conclusion and wrap up – Jennifer Young, IESO

The IESO thanked all participants and that the IESO welcomes feedback from all stakeholders. Feedback should be sent to engagement@ieso.ca by March 8. Feedback on this Market Rule amendment proposal should be sent to rule.amendments@ieso.ca by February 21, 2019.

Meeting adjourned at 1:00 pm.

Action Item Summary

Responsible Party	Action Item
IESO	Provide statistics on the performance of previous years' HDR resources.
IESO	Consider a two-week window for the DR test similar to other markets.
IESO	Review internally to see if LDC interval data can meet IESO requirements.
IESO	Consider allowing participants to submit data at the contributor level.
IESO	Clarify in Market Manual 12 that the IESO does not intend to go back 7 years to audit.
IESO	Provide more information on the review of requirements for behind-the-meter storage as part of the DR program.
IESO	Consider where principals governing open access and competition on the distribution system should be discussed.
IESO	Identify for stakeholders which engagements each issue related to DRWG will be discussed.
IESO	Consider if it would legitimize the proposed amendment if the DRA was open to generators and Resolute did not have a PPA.
IESO	Consider how a resource that can both inject and displace load could get compensated for these services.
IESO	Determine how the Market Rule Amendment Proposal should be addressed now that the DRA will evolve.
IESO	Have a follow-up discussion on timing for the Market Rule Amendment Proposal at the next DRWG meeting.
Stakeholders	Provide further feedback on the Market Rule Amendment Proposal
IESO	Note the need for more information on IESO's position at the Technical Panel.

TAB 22

Evolving the DR Auction to Transitional Capacity Auction

Meeting Ontario's Capacity Needs

Information Session

March 7, 2019

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Disclaimer

This presentation and the information contained herein is provided for information and discussion purposes only. This presentation does not constitute, nor should it be construed to constitute, legal advice or a guarantee, representation or warranty on behalf of the IESO. In the event of any conflict or inconsistency between the information contained in this presentation and the Market Rules, the Market Manuals, any IESO contract or any applicable legislation or regulation, the provisions of the Market Rules, Market Manuals, contract, legislation or regulation, as applicable, govern.

Engagement Objective for March 7th

- Inform stakeholders on Transitional Capacity Auction (TCA)
  - Layout evolution plan for future auctions and path towards ICA
  - Preview of the design approach

- Introduce engagement plan
  - Engagement schedule
  - Feedback opportunities

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Today's Overview

- Background and Objectives
- TCA Overview
- Rationale
- TCA Stakeholder Engagement Plan and Project Schedule
- Enabling Resources
- TCA Preliminary Design
  - DR Auction Design Features
  - Evolution from DR Auction
- Next Steps

BACKGROUND & OBJECTIVES

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Background

- Ontario will emerge from surplus conditions next year and capacity is required to meet resource adequacy needs
- Starting summer 2020, Ontario’s capacity need in the near term can be met by enhancing the existing DR auction
- In a phased approach, the IESO will enhance the existing DR auction by updating or developing features and expanding competition to other resource types – a key feature of TCA
- IESO is expecting that the Market Renewal Projects will come into service around 2022
- The evolution into a Transitional Capacity Auction (TCA) is a practical approach allowing both the IESO and Market Participants to realize learnings and improve designs for the enduring Incremental Capacity Auction (ICA)
- The TCA will enable an effective transition to the first ICA in Q4-2022

TCA Objectives

- Evolve existing DR Auction to ensure resource adequacy from 2020 to 2024 until the comprehensive ICA has successfully run its first auction

Principles

- Evolve the Demand Response (DR) auction mechanism aligned with the following Market Renewal Program (MRP) principles:
  - Efficiency
  - Competition
  - Certainty
  - Transparency
  - Implementability

TCA OVERVIEW

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Transitioning from the DR Auction

- The DR Auction is an existing mechanism that provides a transparent and cost-effective way to select the most competitive providers of Demand Response capacity
- The DR Auction was always intended to be transitioned to broader capacity auctions
- Evolving the DR Auction to a Transitional Capacity Auction (TCA) provides:
  - Flexibility to meet emerging needs
  - A staged approach towards the competitive marketplace envisaged under ICA
  - Lessons learned for IESO and market participants

Transitioning from the DR Auction

- TCA will replace DR Auction
- Open up competition to additional resources and enable some ICA design features not included in current DR auction in a phased approach:
  - **TCA Phase 1 (2019)** – Open competition by adding dispatchable, non-obligated generators to current eligible DR participants (i.e., limited changes)
  - **TCA Phase 2 (2020 and beyond)** – Series of auctions that may enable more resources such as imports, self-schedulers, and uprates and incorporate ICA design features

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Transitioning to the Incremental Capacity Auction (ICA)

- Opportunities to transition to the ICA may be incorporated in TCA Phase 2
  - Selected design features from the ICA may be incorporated
  - The TCA is not intended to replace ICA. The TCA is a incremental step the IESO is introducing prior to the ICA implementation

- TCA Phase 2 is expected to be implemented over multiple years
  - Throughout this time the IESO will engage stakeholders for feedback

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Potential Issues to Design Approach

- Timeline and frequency of future TCA auctions
- Demand curve development process
- Setting TCA target capacity
- Enabling of additional resources
- New and modified auction features

RATIONALE

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Address Capacity Need

- IESO's September 2018 Planning Outlook highlighted:
  - As of 2020, capacity is adequate when including all the existing measures (such as capacity acquired by the DR Auction)
    - Some generators participate in our energy markets without a contract
    - More generators continue to come off contract each year, including Lennox (by end of 2022) at a time when nuclear refurbishments are underway and Pickering station is scheduled to close
    - The TCA will provide an opportunity for these off-contract resources to compete to meet system needs by providing capacity, in addition to their participation in the energy market
  - By 2023, there is a significant need for additional capacity - beyond what the capacity already committed by regulated rates and long-term contracts
    - IESO is confident that Ontario has a robust asset base and strong interconnections that will ensure we can meet our system needs without having to procure new resources through long-term contracts

Transparent Platform for Acquiring Capacity

- The DR Auction is an established framework for acquiring DR capacity and is a good starting point for securing capacity needs through a market-based mechanism
- The DR Auction has run successfully since 2015 reaching a more mature state through increased participation in offered capacity (MWs) and increasing number of new participants
    - Prices to acquire capacity have dropped by over 40% since the first auction

Expanding participation to other resources will increase competition and will further benefit consumers

STAKEHOLDER ENGAGEMENT PLAN

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Stakeholder Engagement Plan

- Engagement Objectives
  - Ensure stakeholders understand the changes involved in the development of the TCA
  - Seek to understand how proposed changes to the current DR Auction may affect stakeholders
  - Gather stakeholder feedback on any significant issues and potential solutions associated with the proposed design features

Stakeholder Engagement Plan

- Two-phased approach
  - Phase One will focus on making the necessary changes to evolve the DR Auction to enable other resource types to participate
  - Phase Two will focus on the ongoing evolution of the TCA including further necessary changes to enable additional resource types to participate and to build learning for the ICA
- Opportunities for feedback
  - Meetings and/or webinars to be held throughout Phase One and Two
  - Two-week comment periods for written feedback on Phase One and Two designs

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Engagement Schedule

Timing	Engagement Activity
Phase One Engagement	
March 7, 2019	Introductory discussion and presentation of the design approach • Discuss the purpose of the engagement and high-level work plan for 2019; discuss areas for feedback; solicit initial feedback on proposed engagement approach
Early April, 2019	Meeting to review proposed Phase One design • Discuss changes to DRA proposed in Phase One
Early April, 2019	Release of Phase One design • Seeking feedback on key challenges, barriers, and opportunities
Two week period in April	Window for written submissions on Phase One design
Two weeks after the comment period closes	IESO to post responses to written submissions on Phase One design
Q2 – Q3, 2019	Additional in-person meetings or webinars to discuss design details as required
Phase Two Engagement	
Q3, 2019	Meeting to review Phase Two design • Discuss changes to TCA proposed in Phase Two
Q3, 2019	Release of Phase Two design • Seeking feedback on key challenges, barriers, and opportunities
Two week period in Q4, 2019	Window for written submissions on Phase Two design
Two weeks after the comment period closes	IESO to post responses to written submissions on Phase Two design
Post-2019	Additional in-person meetings or webinars as required

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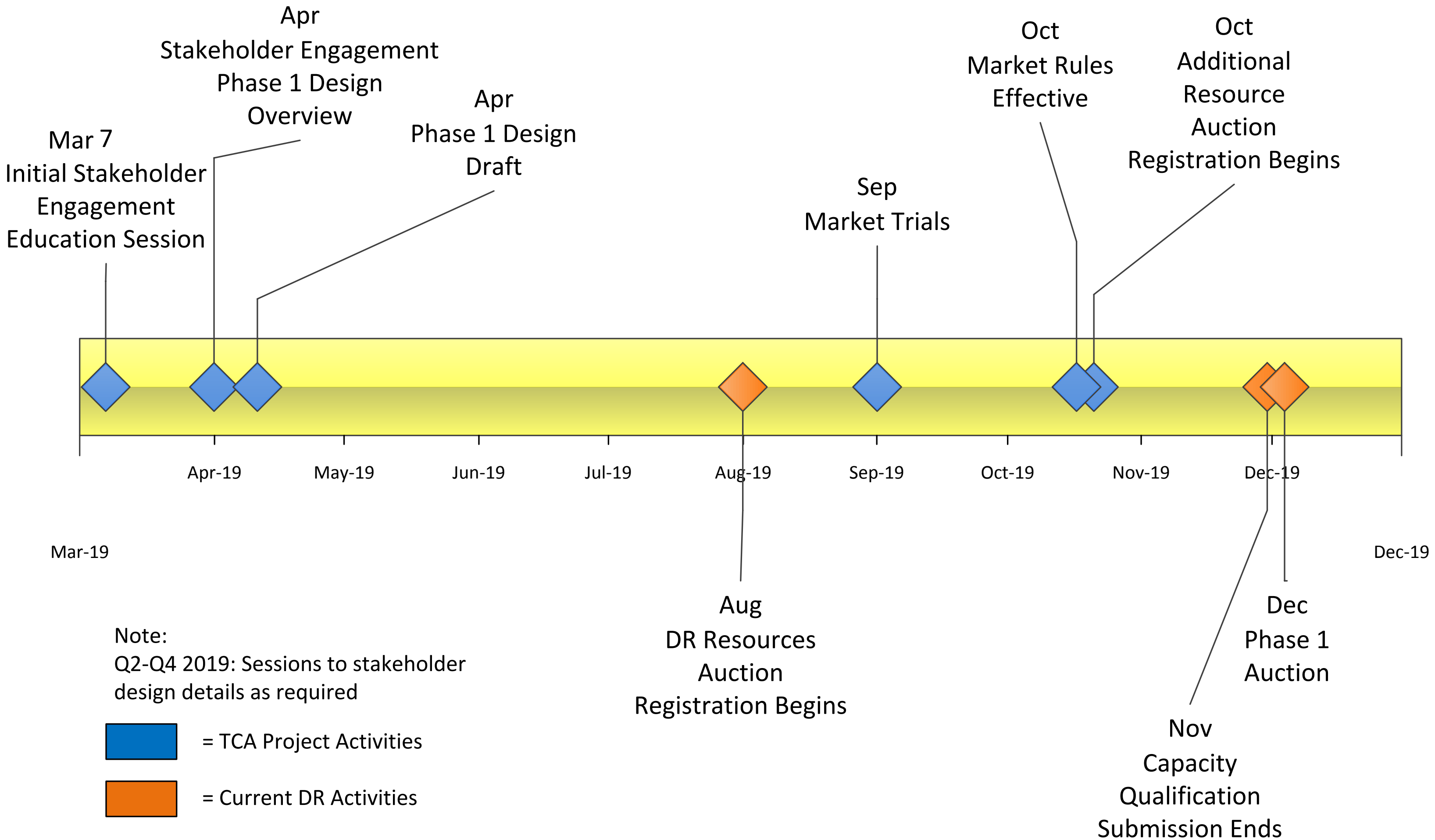
PROJECT PLAN

TCA Schedule – Milestones Phase 1

Transitional Capacity Auction Project Schedule – Phase 1: 2019

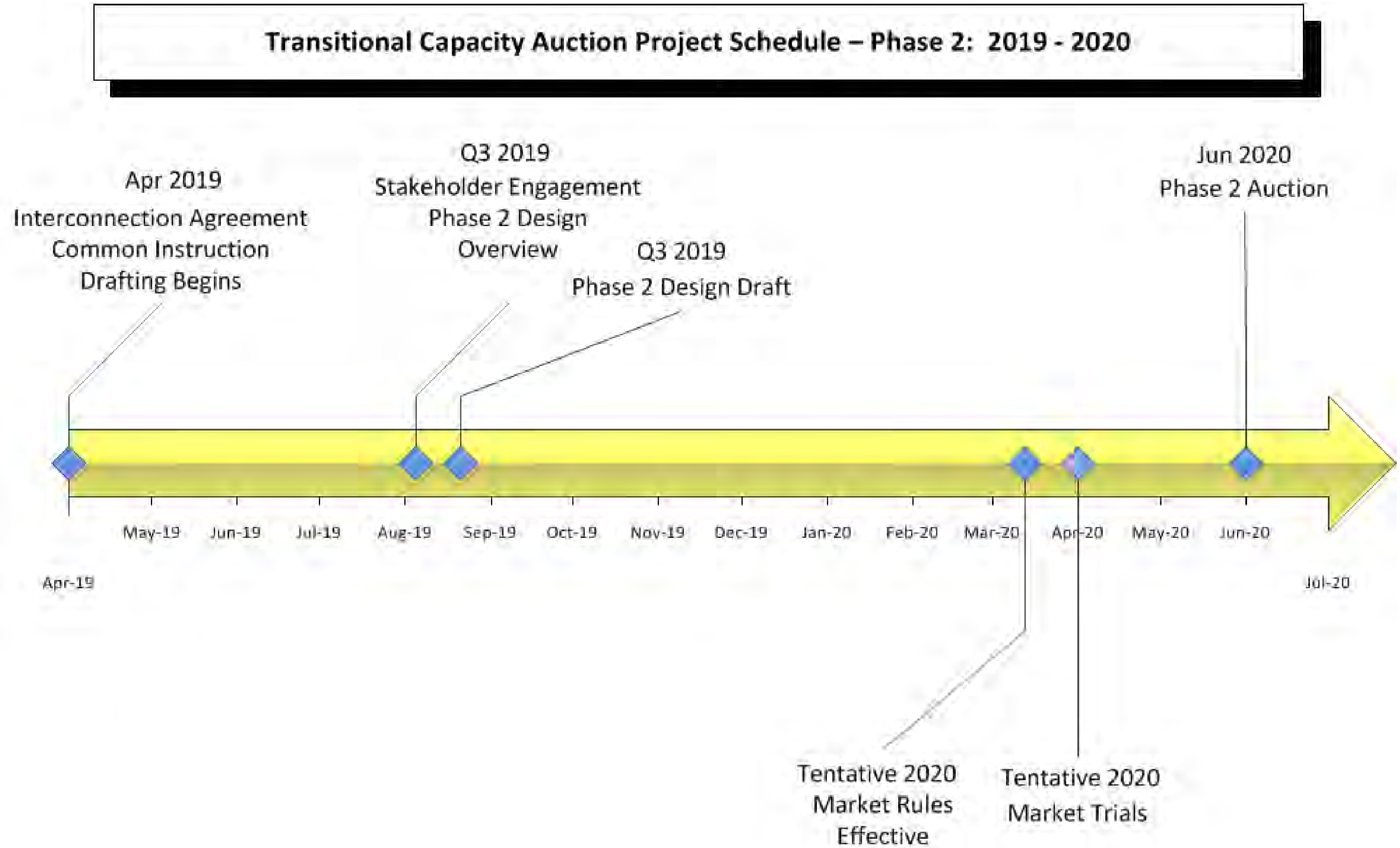


Note:
Q2-Q4 2019: Sessions to stakeholder design details as required

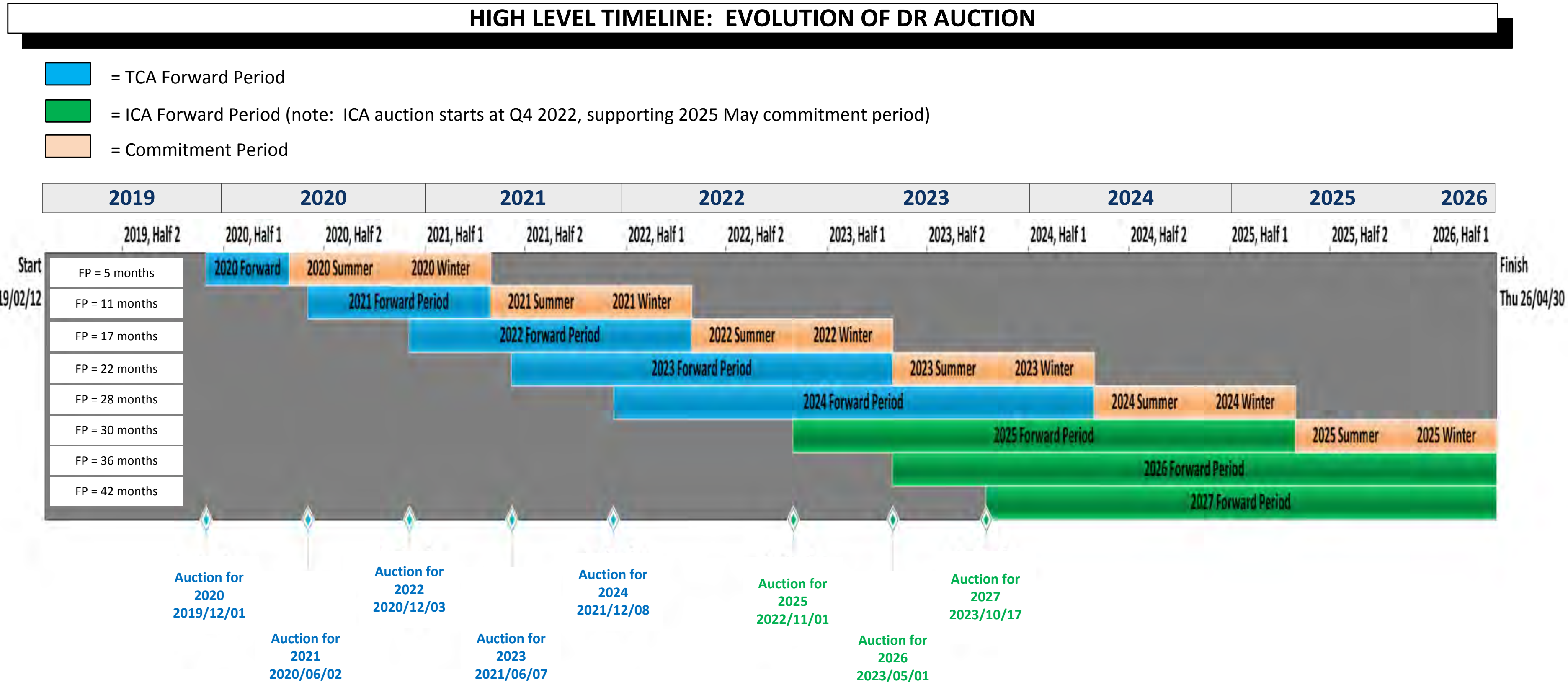
= TCA Project Activities

= Current DR Activities

TCA Schedule – Milestones Phase 2



Proposed TCA Transition Timelines*



Assumptions:
1) Auctions take place approximately semi-annually until forward period = 2.5 yrs.
2) First ICA takes place by Q4 2022.

*The details presented are for illustrative purposes only and are subject to change

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Enabling Resources

- Providing capacity to meet resource adequacy means that the capacity has to be delivered into the energy market
  - IESO recognizes that not all resource types are currently enabled to effectively participate in its current energy market
- Through the Market Development Advisory Group, the IESO will examine the gaps and opportunities for enabling and enhancing existing, new and emerging resources to deliver services to the IESO
- Due to the time constraints for the TCA, the IESO will focus on resources that are currently enabled in the energy market in Phase 1 and will put together a plan for phasing in additional resources in Phase 2
- As more eligible resources are enabled in the TCA, updates will be made to the Market Rules, Manuals, and Tool(s) to incorporate resource specific requirements

Draft Considerations for Resource Participation

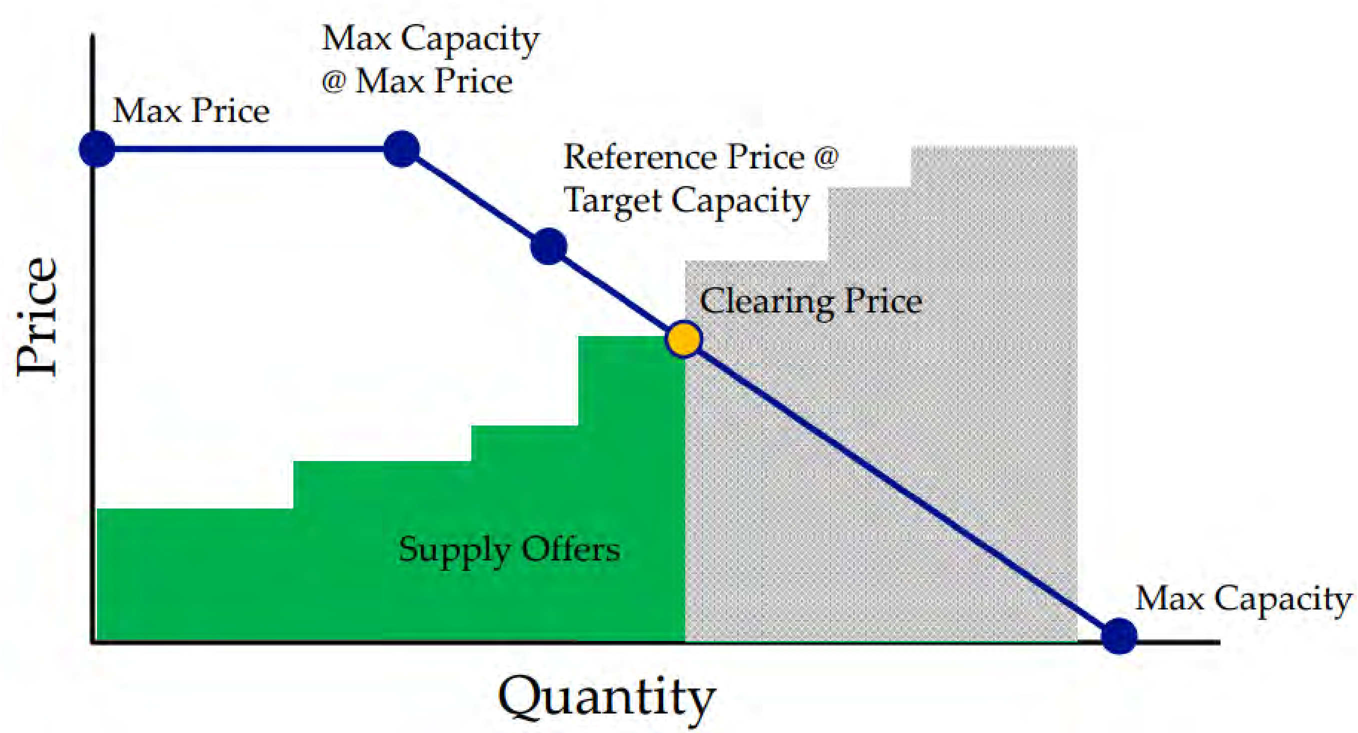
Resource Type	Anticipated Participation Date	Enhancements and Design Considerations	Other Considerations and Requirements
Demand Response	2019	Changes informed by DRWG	
Existing uncommitted dispatchable generators	2019	Incremental Change in Phase 1 of TCA	
System-backed imports	2020	Deliverablility, process enhancements and tool changes (real-time and settlement)	Operating Agreement needed
Resource-backed imports	2021	Requires more sophisticated deliverability consideration	Operating Agreement needed
Uprates	2021	Forward period obligations requirements	Contractual implications
Self-scheduling	2021	Process needed to assess historical performance	Self-scheduling resources could become dispachable
New directly-connected resources	TBD	Sophisticated process needed to assess project development milestones	
Existing Dx-connected resources	TBD		IESO developing DER Workplan
New Dx-connected resources	TBD		IESO developing DER Workplan

TCA PRELIMINARY DESIGN APPROACH FEATURES (TRANSITION FROM DR AUCTION)

DR Auction Overview

- **Objective:** To maximize the area under the demand curve minus supplier costs for cleared offers
- **Inputs:**
  - Offers from Demand Response Auction Participants (DRAP)
  - Demand Curve elements
  - Zonal Constraints
- **Output:**
  - Capacity Obligations for each successful DRAP
  - Auction Clearing Prices – for Ontario and any constrained zones
- **Mechanics:**
  - The **Ontario-wide auction clearing price** will be equal to the price associated with the last cleared offer
  - When there is an auction offer not selected, either partially or in full, due to the total maximum zonal constraint, the **auction clearing price for that zone** will be set at the lesser of:
    - the price associated with the next economic quantity from an auction offer in the same zone that would have cleared but for the total maximum zonal constraint; or
    - the Ontario-wide auction clearing price

DR Auction Downward Sloping Demand Curve



- Parameter values developed through the Demand Response Working Group (DRWG) and reviewed triennially
- The total quantity cleared through a demand response auction may clear above the demand curve where doing so will maximize the overall objective function

Staged Approach

Demand Response Auction (DRA) → TCA (Phase I) → TCA (Phase II) → ICA

Design decisions made for each step

Design Elements Under Consideration

1. Registration
2. Prudentials and Deposits
3. Public Reporting
4. Qualified Capacity
5. Forward Period
6. Forward Obligations
7. Seasonal Commitments
8. Demand Curve Shape
9. Demand Curve Parameters
10. Capacity Transfers and Buyouts
11. Performance Obligations
12. Performance Assessments
13. Non-Performance Charges
14. Cost Recovery
15. Processes to Challenge the IESO

Registration

Design Feature(s)	Description
Registration	Process where auction participants provide organizational and resource related information to participate in the auction and deliver on its capacity obligation

DRA

- All DR participants
  - Register as DRAP - one time requirement
  - Qualify capacity – prior to every auction
  - Submit auction deposit – prior to every auction
  - Authorize as DRMP – one time requirement
  - Register resources – after every auction
  - Manage contributors – after every auction for each month during commitment period

TCA

- Only incremental changes from DRA

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Prudentials and Deposits

Design Feature(s)	Description
Prudential	Collateral posted to establish creditworthiness of the participant and cover for any potential default situations
Deposits/Security	Financial amount submitted to ensure high quality participants participate in the auction

DRA

- All DR auction participants must submit deposits as a pre-requisite to qualify capacity and after successful in the auction post prudential prior to the start of the commitment period

TCA

- Only incremental changes from DRA

Public Reporting

Design Feature(s)	Description
Public Reporting	Publish auction reports

DRA

- Publish pre-auction report:
  - Deadlines
  - Auction parameters
  - Zonal limits
  - Publish post-auction report:
    - DR auction results zonal summary
    - DR participant capacity obligations
    - DR participant surplus qualified capacity

TCA

- Phase 1: Only incremental changes from DRA
- Phase 2: May consider publishing transmission congestion report and local need

Qualified Capacity

Design Feature(s)	Description
Qualified Capacity	Total maximum capacity that each participant can offer in the auction

DRA

- DR auction participants must submit quantity for commitment period(s), zonal location, identify resource type (Physical and/or Virtual), and submit auction deposit

TCA

- Phase 1: Only incremental changes from DRA
- Phase 2: Consider phasing in ICA elements

Forward Period

Design Feature(s)	Description
Forward Period	Length of time after auction results are posted and before the first day of the commitment period

DRA

- 5 months for the summer commitment period
- 11 months for the winter commitment period

TCA

- Phase 1: No change from DRA
- Phase 2: Gradually increase the forward period in ~6 month increments as per the proposed TCA transition timelines up to ~2.5 years

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Forward Obligations

Design Feature(s)	Description
Forward Obligations	Requirements auction participants with capacity obligation must fulfill before the start of the commitment period

DRA

- All DR participants:
  - Must authorize as DRMP
  - Must register resources
  - May be required to allocate virtual demand response capacity obligation

TCA

- Only incremental changes from DRA

Seasonal Commitments

Design Feature(s)	Description
Seasonal Commitments	Length of time that accounts for seasonal demand characteristics and supply capability over which auction will secure capacity resources

DRA

- Seasonal commitment periods – Summer (May 1 – October 31) and Winter (November 1 – April 30)
- DR participants qualify capacity, offer, and secure capacity obligations separately for each commitment period – no co-optimization

TCA

- No change from DRA

Demand Curve Shape

Design Feature(s)	Description
Demand Curve Shape	Shape of curve to help conduct the auction and acquire capacity

DRA

- Parameter values developed through the Demand Response Working Group (DRWG) and reviewed triennially

TCA

- TCA will adopt the DR demand curve shape (straight downward sloping line)
- Parameter values are subject to change (next slide)
- Target Capacity will be no less than existing Target Capacity and may increase if a significant capacity need arises
- Reference price is subject to change in Phase 2
- Minimum and Maximum Zonal limits are subject to change in Phase 2

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Auction Parameters

Design Feature(s)	Description
Auction Parameters	Parameters that help conduct the auction and acquire capacity

DRA	TCA

DRA

- Parameters for each commitment period :
  - Target Capacity – Informed by previous allocated DR contracts, policy target, and IESO identified system reliability need
    - For 2018 DR auction, Summer – 611 MW; Winter – 606 MW
  - Zones and Zonal Clearing – 10 Electrical zones and zonal limits are respected with prices set as per zonal pricing mechanism
  - Zonal Maximum Limit –Maximum transmission/system capability
  - Zonal Minimum Limit – No zonal minimum
  - Maximum Auction Clearing Price– 1.25 multiple based on LTEP forecasted net cost of building new Single Cycle Gas Turbine Plant

TCA

- All input auction parameters may be updated as per the present DRA process and:
  - Target Capacity – Informed by resource adequacy needs
    - Phase 1 – Summer – 611 MW; Winter – 606 MW
  - Zonal Maximum Limit - may change as per resource adequacy need and transmission transfer capability
  - Phase 2 only – Zonal Minimum Limit may be added as per the resource adequacy need in each zone.
  - May consider using Net Cost of New Entry (CONE) to update inputs to the demand curve

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Capacity Transfers and Buy Outs

Design Feature(s)	Description
Bilateral Capacity Transfer	Option available to the auction participants with capacity obligation to transfer their obligation to another auction participant with surplus qualified capacity
Buy Outs	Option available to the auction participant that do not want to stay obligated to provide the capacity secured via the auction

DRA

- DR participants with capacity obligation can either transfer their capacity (like for like) or buy-out as per their situation

TCA

- Phase 1: Buy-out option will only be available to the virtual DR participants
- Phase 2: Buy-out option may be removed completely once zonal minimum capacity is included due to resource adequacy needs and system reliability concerns

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Performance Obligations

Design Feature(s)	Description
Performance Obligations	Requirements that a capacity resource must fulfill during the commitment period

DRA → TCA

DRA

- All DR resources:
  - Qualify Capacity by submitting required information
  - Must offer capacity in the day-ahead and real-time energy markets

TCA

- Phase 1: Only incremental changes from DRA
- Phase 2: Improvements will be required as qualified capacity requirements will be updated

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Performance Assessment

Design Feature(s)	Description
Performance Assessment – Measure against Obligations	Evaluation of performance of a capacity resource for the secured capacity obligation during the commitment period

DRA

- Performance is assessed by:
  - After the fact checking for availability, capacity, dispatch, and measurement data submission. Non-performance charges are applied as per the violation of the checks
  - DR resources are subject to up to 2 test activations during the commitment period. Non-performance charges are applied when DR resource fails to provide capacity and/or follow dispatch

TCA

- Phase 1: Only incremental changes from DRA
- Phase 2: Performance assessment may be different for other eligible resources (i.e. imports)

Non-Performance Charges

Design Feature(s)	Description
Non-Performance Charges	Charges meant to discipline the participants for not performing as per the obligation and promote compliance with capacity obligations

DRA

- There are four types of non-performance charges that may apply:
  - After the fact checking for availability, capacity, dispatch, and measurement data submission. Non-performance charges are applied as per the violation of the checks
  - DR resources are subject to up to 2 test activations during the commitment period. Non-performance charges are applied when DR resource fails to provide capacity and/or follow dispatch

TCA

- Changes to non-performance factors
- May remove deadband for capacity charges for test activations

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Cost Recovery

Design Feature(s)	Description
Cost Recovery	Means to recover the net costs incurred by the IESO for availability payments to the auction participants with capacity obligation (net of non-performance charges)

DRA

- Cost Recovery is done in "Global Adjustment like" manner using charge types 1350 and 1351

TCA

- Phase 1: No change from DRA
- Phase 2: May be updated to be consistent ICA.

Processes to Challenge IESO

Design Feature(s)	Description
Processes for MPs to Challenge IESO Determinations	Process that MP can trigger to question or challenge IESO determinations regarding rules, auction results, and settlements

DRA	TCA
• No set process for challenging auction results. DR auction participants directly contact IESO customer relations for inquiries • For issues with settlements, DR participants can submit a Notice of Disagreement (NOD) • For any DRA Market Rules dispute, DR participants can utilize the MR dispute resolution process	• No change from DRA

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ICA Features not in TCA

- Individual capacity qualification
- Minimum hours of dispatch
- Seasonal co-optimization
- Rebalancing Auctions
- New build requirements (siting, forward period requirements, security, multi-year commitment, etc.)
- Market power mitigation
- Delisting requirements
- Enhanced obligations, assessment and non-performance implications

Next Steps

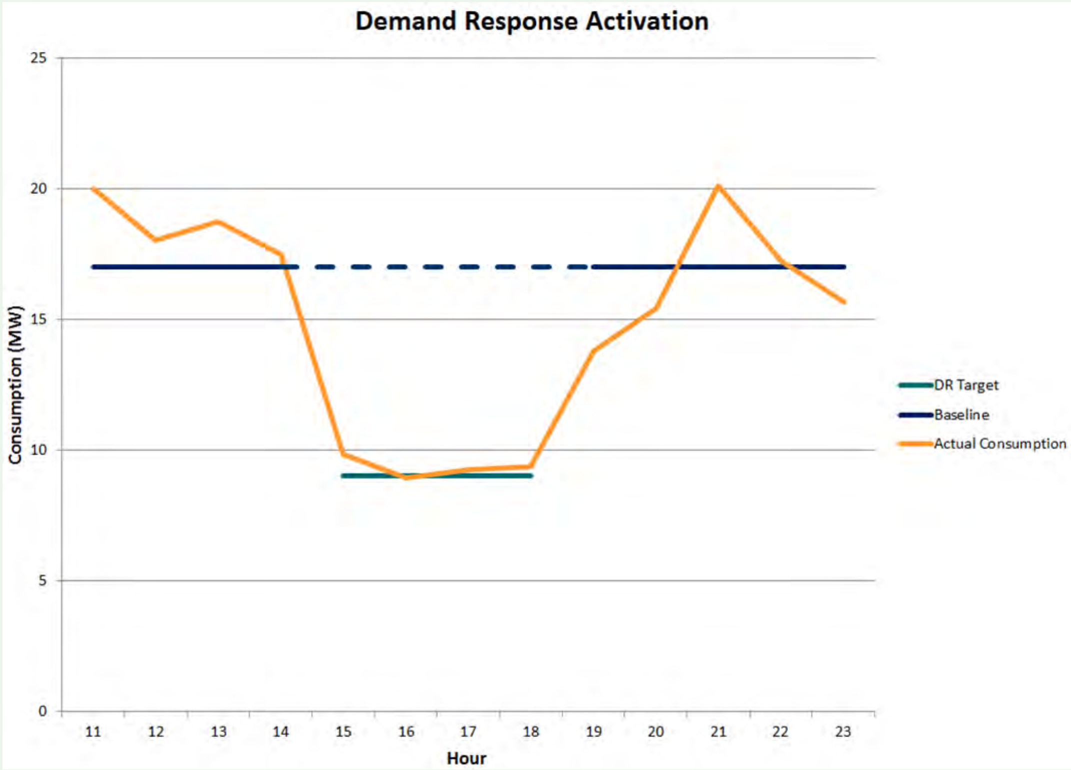
- March: Stakeholders are asked to provide written feedback on engagement plan to engagement@ieso.ca
- April: IESO to host engagement session on TCA and publish Phase 1 design
- Questions for stakeholder consideration:
  - Is the engagement plan adequate to identify major issues and concerns?
  - Are significant ICA or DRA features and/or resoures excluded from the TCA that should be included that would prevent the IESO from acquiring capacity?

Questions

APPENDIX

DR Auction Overview

- DR auction is a market based mechanism that ensures cost-effective procurement of DR resources
- DR refers to changes in electricity use made by end-use consumers in response to the price of electricity and/or times of reliability need
- In return for receiving a capacity payment, DR providers must make themselves available in the IESO energy markets
- Failure to follow dispatch, provide capacity, and/or submit measurements data result in applicable non-performance charges



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DR Auction Overview

- DR provides value to the system as capacity is used to help maintain reliability while also providing an alternative to dispatching traditional supply resources
- DR Auctions are held on an annual basis in December for:
  - Summer Commitment Period – Availability Window: 12:00 to 21:00 EST for all business days, May – October, 2020 and
  - Winter Commitment Period – Availability Window: 16:00 to 21:00 EST for all business days, November, 2020 – April, 2021
- Ontario's demand response capability can come from a variety of consumers:
  - Physical (Industrial Loads)
  - Virtual (Demand Aggregators, Commercial and Institutional and Residential)

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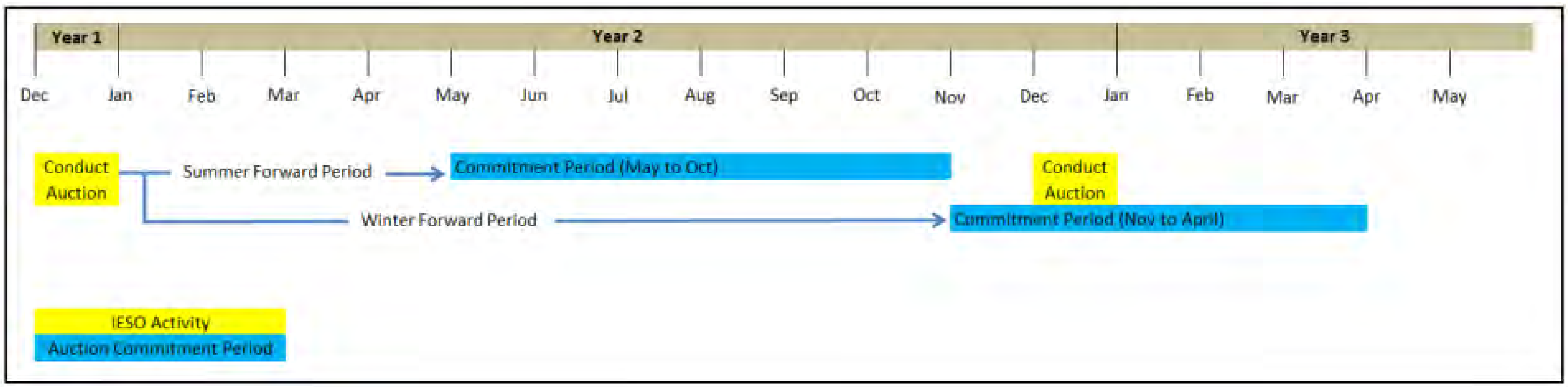
DR Auction Timelines



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TAB 23

Demand Response Working Group – Meeting Notes

April 25, 2019

Meeting Notes

Dates held: April 25, 2019	**Time held**: 9:00am to 1:00pm	**Location**: Four Points by Sheraton Toronto Airport
Company	**Name**	**Attendance Status** (A) Attended; (WebEx) Attended via WebEx
360 Energy	Williams, James	Webex
Alectra Utilities	Mortage, Hamza	Webex
Ameresco Canada Inc.	Fonger, Jim	A
AMPCO	Anderson, Colin	Webex
Bruce Power	Zhang, Alvin	A
Cascades	Ross, Jean-Philippe	A
CGI Utilities	Hughes, Graham	A
CGI Utilities	Van Den Hoed, Mattijs	Webex
City of Toronto	Cheng, Jessie	A
City of Toronto	Gu, Michael	Webex
Cpower Energy Management	Hourihan, Mike	Webex
Customized Energy Solutions	Luukkonen, Paul	A
Customized Energy Solutions	Withrow, David	Webex
Direct Energy	Cavan, Peter	Webex
Ecobee	Houle, Jonathan	A
EDF Renewables	Thornton, David	Webex
Enel X	Chibani, Yanis	A
Enel X	Doremus, Steve	Webex
Enel X	Griffiths, Sarah	A
Energy Hub	Im, Brian	Webex
Great Circle Solar Mgmt Corp	Antic, Tina	Webex
Great Circle Solar Mgmt Corp	Wharton, Karen	Webex
HCE Energy	Crown, Mike	Webex
Lakeland Holding	Gilbert, Jeff	Webex
Ministry of Energy, Northern Development and Mines	Kersman, Paul	Webex
Market Surveillance Panel	Koetsier, John	Webex
Nest Labs/Stem	Amaral, Utilia	A
Northland Power	Samant, Sushil	A
Northland Power	Zajmalowski, Mike	A
NRG Curtailment Solutions, Inc.	Briggs, Kara	Webex
NRG Curtailment Solutions, Inc.	Popova, Julia	Webex
NRG Curtailment Solutions, Inc.	Vukovic, Jennifer	Webex
Ontario Power Generation	Kim, Jin	A
Power Advisory	Lusney, Travis	A

Dates held: April 25, 2019	Time held: 9:00am to 1:00pm	Location: Four Points by Sheraton Toronto Airport
Company	**Name**	**Attendance Status**
Power Advisory	Simmons, Sarah	Webex
Powerful Solutions	Inman, Peter	Webex
Resolute Forest Products	Degelman, Cara	A
Rodan Energy Solutions	Forsyth, Dave	A
Rodan Energy Solutions	Goddard, Rick	A
Rodan Energy Solutions	Quassem, Farhad	A
Rayonier Advanced Materials	Laflamme, Serge	A
Southcott Ventures	Lampe, Aaron	A
Toronto Hydro	Marzoughi, Rei	Webex
TransCanada Energy	Kuntz, Margaret	A
Rayonier Advanced Materials	Laflamme, Serge	A
University of Toronto	Janusz, Alexander	Webex
Voltus	Strawczynski, Zygmunt	A
Voltus	Grav, Jorgen	Webex
IESO	Campbell, Alexandra	A
IESO	Farmer, Chuck	A
IESO	Kahlon, Jasdeep	A
IESO	Nusbaum, Stephen	A
IESO	Rashid, Fahad	A
IESO	Savage, Jessica	A
IESO	Tang, Jessica	A
IESO	Versteeg, Peter	A
IESO	Wagner, Tam	A
IESO	Woo, Phillip	A
IESO	Young, Jennifer	A
IESO	Yung, Ambrose	A
IESO	Zaworski, Richard	A

Please report any corrections, additions or deletions by e-mail to engagement@ieso.ca. All meeting materials are available on the IESO web site at: http://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Working-Groups/Demand-Response-Working-Group

Hourly Demand Response (HDR) Testing Update – Ambrose Yung, IESO

The IESO provided an update of HDR Testing results and the HDR Test Activation Protocol.

Participants asked what timeframe HDR testing results covered, how many resources passed, and how the results would change if resources were tested for only 2 hours instead of 4.

The IESO explained that HDR testing results presented covered the February 2018 to January 2019 period, only 42% of HDR resources passed testing, and that at least 39% of HDR resources would still fail the test if it was limited to 1 hour as these resources failed in all hours of the 4 hour test.

Participants asked if all the tests had occurred on the same day, and how many failures were repeat failures.

The IESO replied that it had tested all the HDR resources on the same day, and that it will look into providing more information on repeat failures.

A participant asked how many failures were referred to the Market Assessment and Compliance Division (MACD), if similar tests are conducted for generators, and if a sample DR Test Advisory Notice for testing could be provided.

The IESO replied that none of the failures have been referred to MACD; there are tests in place for generators, and the IESO would work with market participants on sample notifications.

Editor's Note: A sample DR Test Advisory Notice was sent to all DRMPs via email on May 17, 2019 and has been posted on the DRWG website.

Participants asked if the test is invalid if the DR Test Advisory Notice fails to deploy.

The IESO replied that the test remains valid and that participants should rely on the standby and activation notifications.

Participants noted that actions during the in-day adjustment period can cause resources to fail tests and asked if the IESO had considered reducing the number of hours in the in-day adjustment period.

The IESO noted that the adjustment period is part of the baseline calculation and changing the number of hours would be a design change that would require further analysis and stakeholdering through DRWG.

DR Auction: Path to Success in the TCA – Yanis Chibani, Enel X

Enel X led stakeholders through their discussion on removing barriers for DR and improving efficiency in the TCA. Participants broadly noted that the Enel X presentation highlighted the challenges that all demand resource resources face and that these challenges have become more important as competition with other resources are being rapidly introduced. Participants wanted to make sure that the issues identified will be resolved in time for the TCA.

Participants asked why enabling merchant generation for phase I of the TCA was a higher priority than improving rules for DR.

The IESO replied enabling imports and generators would not require tool changes and that there is a need for this capacity. Further, there is nothing stopping additional expansion of DR in the TCA.

Participants asked how LDCs are being engaged for the TCA, if more competition means more MW or a better-defined reliability product, and if uprates would be considered.

The IESO replied that they are engaged with LDCs and there will be more outreach throughout the year, competition comes from more MW and more resources, and *uprates are not being considered at this time as the TCA is being opened up first to resources that are already participating in the energy market today.*

Participants asked if testing for 4 hours made sense for 1 hour dispatches and noted that a single 4 hour tests could be done to prove a resource, subsequent tests could be shorter.

The IESO replied that notionally 4 hours is likely what is needed to meet reliability needs.

Editor's note: IESO can dispatch HDR resources to up to 4 hours and 4-hour test is required by the IESO to test HDR's capability to deliver its obligation for 4 hours.

A participant noted that costs are incurred if the IESO cancels an HDR test on short notice and asked if cost recovery or completion of the 4 hours to get credit was possible.

The IESO replied that when it conducts testing it must provide activation notice at least 2 hours in advance of the test period. In addition, IESO also considers historical test and in market performance for scheduling test activation for a resource.

A participant noted that the IESO should look at other markets for best practices and asked how dispatchable loads are tested.

The IESO replied that it will come back to stakeholders with a broader conversation around testing.

Discussion: Next Steps in Evolving DR participation – Alexandra Campbell, IESO

The IESO led stakeholders through a broad discussion on evolving DR participation, including the future of DRWG and the DRWG work plan. The discussion became centered on the need and rationale for utilization payments for DR, and participants stressed that utilization payments are a priority for DR.

Participants noted that FERC had ruled that DR resources should receive utilization payments equal to LMP, that utilization payments are a regulatory best practice, and that utilization payments may bring down bids. Participants further asked what questions needed to be answered to move utilization payments forward.

The IESO replied that in Ontario, utilization payments would receive the same types of challenges that they did during the stakeholdering of the FERC Order 745 and the IESO would need a made-in-Ontario rationale supported by a good business case to consider it. If the priority for DRWG is to address utilization payments, then it can move this forward on this but asked if there were other priorities given how rarely DR gets dispatched.

Participants emphasized that utilization payments have always been on their list as a priority but the IESO dictates priorities. It made a unilateral decision to make DR compete with merchant generators on a condensed timeline, which is why participants have escalated the discussion on utilization payments.

The IESO replied that the next steps would be to determine how to move forward from the Navigant paper released in December 2017 on utilization payments. The IESO is open to any new rationales for utilization payments and models from other markets.

A participant asked for a direct response on the key Enel X presentation points.

The IESO replied that it will respond to these points.

Meeting adjourned at 1:00 pm.

The IESO thank all participants and that the IESO welcomes feedback from all stakeholders. Feedback should be sent to engagement@ieso.ca.

Action Item Summary

Responsible Party	**Action Item**
IESO	Provide more information on repeat failures in HDR testing
IESO	Provide background information on testing for other resource types
IESO	Provide an updated proposal on measurement & verification and testing.
IESO	Provide an approach on how to proceed with the analysis of utilization payments
IESO	Provide a direct response on the key Enel X presentation points

TAB 24

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

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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

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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

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

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

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)*

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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

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

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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?

6. SUMMARY AND NEXT STEPS

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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

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 25

July, 2019

IESO PROPOSED CAPACITY AUCTIONS & DEMAND RESPONSE RESOURCES

AEMA/AMPCO BRIEF

Summary of Concerns and Recommendation.

1. The Ontario Independent Electricity System Operator's (IESO) proposal for developing a broadened capacity auction is part of the IESO's overall Market Renewal Program (MRP). The overall objective of the MRP is to encourage and enhance competition[1]:

   Creating a stable and efficient marketplace that produces value for consumers involves encouraging competition and innovation among suppliers – and is the catalyst behind initiatives to resolve long-standing market design issues.

2. Proceeding with a broadened capacity auction, in the form of the "Transitional Capacity Auction" (TCA) currently proposed, without first resolving how demand response (DR) resources are compensated for the value that they provide to the IESO administered market (IAM) would not only fail to further this objective, it would undermine this objective.

3. It has been definitively recognized that DR resources can provide electricity wholesale market energy services, and that failure to compensate DR resources for such services in a manner equivalent to compensation provided to generation resources for similar services is unjust and unreasonable.

4. Without ensuring just and reasonable compensation to DR resources, on a comparable basis with other resources which bring similar value to the IAM, the TCA proposal could result in replacement of one set of capacity providing resources with another. This would not enhance competition, but it may well stifle it.

5. While the IESO has indicated that it will address the issue of compensation of DR resources for the value that they provide to the IAM, resolution of this issue is not anticipated prior to the proposed December 2019 implementation of TCA Phase I.

6. Fortunately there appears to be no urgency to proceeding with the TCA. On July 16, 2019 the IESO indicated that it would suspend further work on an "Incremental Capacity Auction" (ICA), the mechanism towards which the TCA was to evolve, in light of an imminent forecast indicating sufficient baseload and other resources to ensure reliability for the foreseeable future. The IESO indicated that work on the TCA would continue as currently planned. The current plan is for an initial TCA by the end of 2019.

7. As there is currently no time frame within which a full ICA program is required, there is no rationale for implementing a TCA prior to resolution of the issue of just and reasonable

[1] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 1.

compensation for DR resources in the IAM, and all the more reason for getting the TCA right initially so that it will facilitate, rather than undermine, competition.

8. ***Implementation of the TCA should be deferred. It would be more appropriate and more equitable, and it would better achieve the IESO's stated objectives, to forego the proposed "Phase I" TCA implementation in December, 2019 and instead focus on getting the proposed TCA right from its initiation.***

Background and Current Status.

9. DR is the changing of electricity consumption patterns by end-use consumers in response to market prices.[2]

10. Since 2015 the IESO has held annual demand response auctions (DRAs) to acquire DR capacity from market participants that are able to provide that capacity to the market in exchange for an availability payment[3] (which is for present purposes essentially a "capacity payment" - i.e. a payment to ensure that capacity is available to supply energy services as and when called upon).

11. Four successful DRA's have been held in Ontario, the most recent in December 2018. The IESO's report on the most recent DRA underscores the success of the DRA program[4] [emphasis added]:

> *This year, 38 organizations were registered as auction participants, the highest number since the auction began in 2015. The successful proponents included four new participants who represent a mix of commercial and industrial consumers.*
>
> *The average annual clearing price for availability payments of $52,810/MW represents a 30% decrease from last year, and a 42% decrease since the first auction in 2015. The auction cleared 818 megawatts (MW) for the 2019 summer commitment period and 854 MW for the 2019/2020 winter commitment period.*
>
> *Moving in to its fourth year, the auction has been established as a valuable and reliable tool for the IESO to secure capacity on the system. Decreasing prices year-over-year demonstrates the ongoing maturity of the demand response market as more consumers participate and competition increases. Lower capacity prices benefit all Ontario consumers, while auction participants benefit by offsetting their energy costs and improving their competitiveness.*
>
> *<u>As the electricity system moves towards competitive electricity auctions under IESO's Market Renewal project, the participation of consumers providing demand response will increase competition leading to overall lower prices for Ontario consumers.</u>*

[2] IESO Market Manual, Part 12.0: Demand response Auction, Issue 6.0, page 4, paragraph 1.
[3] IESO News and Updates page; http://www.ieso.ca/en/Sector-Participants/IESO-News/2018/12/IESO-Announces-Results-of-Demand-Response-Auction
[4] *Ibid*

12. Starting in December, 2019 the IESO is proposing to "transition" the DRA into a broader auction by opening participation to other resources.[5] While the "Phase 1" December, 2019 auction was initially proposed as a first step towards transition to an ICA to be implemented in 2022, with the recently announced suspension of work on the ICA, the first TCA will simply be the first in potentially a series of capacity auction evolutionary steps without any defined end state timing.

13. While AEMA/AMPCO support broadening of the DRA into a more robust and competitive capacity auction mechanism, they are concerned that in the current state of the market for DR such broadening will not only fail to enhance competition for the benefit of Ontario consumers, it will have the opposite effect.

14. Generation resources have other revenue opportunities in the IESO administered markets, including payments for energy services provided. DR resources do not currently have commensurate revenue opportunities for the energy services which they provide to the market.

15. As long as this is the case, commandeering the currently successful DRA into a TCA will not broaden the existing auction platform, it will only result in driving the DR resources that participate in that DRA out of the IESO administered market, and replacing one set of capacity auction participants (DR) with another (generators). This would actually be a step backward in evolution of the IESO administered markets, not a step forward.

16. ***AEMA/AMPCO urge the IESO to match the timing for evolution of capacity auctions with resolution of the issue of how to justly and reasonably compensate DR in the broader IESO administered market.***

17. Given that the IESO now does not anticipate in the foreseeable future a period of significant system need, the current proposal to implement the first TCA in December, 2019 cannot be said to be driven by an imminent need to secure capacity. There is no apparent driver for a rush to implementation of a broadened capacity auction this year.

18. ***AEMA/AMPCO urge the IESO to reschedule the first TCA to allow for sufficient time to ensure just and reasonable and non-discriminatory compensation for DR in the broader IAM, thus preserving the ability of the TCA to enhance, rather than restrict, competition.***

Enhancing competition, for the benefit of consumers.

19. As noted above, the overall objective of the IESO's MRP is to encourage and enhance competition[6]:

> *Creating a stable and efficient marketplace that produces value for consumers involves encouraging competition and innovation among suppliers – and is the catalyst behind initiatives to resolve long-standing market design issues."*

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[5] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 2.
[6] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 1.

20. The IESO's proposal to evolve the DRA into a broader based capacity auction is to the same end[7]:

> *The ICA will help us to prepare for [a future period of capacity requirement] by allowing more resource types to compete to provide future capacity, enabling the IESO to flexibly meet the province's adequacy needs.*

21. The success of a broadened capacity auction hinges on expanding participation in competition for the provision of capacity:

> *One of the advantages of the ICA is that all eligible sources of capacity – new and existing, on both the supply and demand sides – compete with each other, regardless of resource type. …From the perspective of meeting adequacy needs, there is no functional difference between a megawatt of power from an electricity generating facility and a megawatt of reduced consumption from demand response.* [8]

22. The TCA would start with the DRA, and add non-committed dispatchable generators as eligible capacity auction participants. The IESO's stated intent in so doing is to *"enable competition between additional resource types"*.[9]

23. At the same time the IESO has acknowledged concerns that there are barriers to DR participation in the IESO markets, and that one of these barriers is the unavailability to DR resources of energy payments.[10]

24. The IESO proposes to study the introduction of energy payments for DR resources (i.e. to determine *"whether there is a net benefit to electricity ratepayers if DR resources are compensated with energy payments for economic activations"*. The study proposed is to be concluded *"before the end of 2020"*, with a next step proposed to be to *"[o]btain input from stakeholders on the approach to conducting the analysis required to make this determination"*.[11]

25. Requiring DR resources to compete against generators without resolving the comparative value of DR resources and generation resources in the energy market, and how to justly and reasonably compensate the former in a manner comparable to the latter, would undermine the current success of the DRA and handicap DR resources from successfully competing within their own existing market platform.

    (a) Generators will bid into capacity auctions taking into account their anticipated energy payments.

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[7] IESO *Incremental Capacity Auction High-Level Design: Executive Summary*, March 2019, page 1.
[8] IESO *Incremental Capacity Auction High-Level Design: Executive Summary*, March 2019, page 3.
[9] *Transitional Capacity Auction Phase I Design Document*, April 11, 2019, p.2.
[10] IESO Demand Response Working Group Meeting Materials, June 19, 2019, pages 54 *et seq.*
[11] IESO Demand Response Working Group Meeting Materials, June 19, 2019, page 7.

(b) DR resources will have to compete against these bids without an equivalent energy payment stream, putting DR resources at a competitive disadvantage to generators in the capacity market.[12]

26. Requiring DR resources to compete with generators in a TCA prior to resolution of the eligibility of DR resources for energy payments would:

(a) Undermine competition and market confidence, a result inimical to the IESO's objectives for the capacity auction program and its MRP in general.

(b) Introduce undue discrimination against DR resources in the expanded auction program by requiring them to compete with generators prior to resolution of their eligibility for energy payments.

(The IESO has recently recognized just this sort of issue in respect of DR compensation for out of market Hourly DR resource activations.[13])

27. Premature introduction of a TCA such that it undermines the ability of DR resources to compete in Ontario's competitive electricity market would be a regressive step in the quest for enhanced competition and innovation.

28. Commandeering the current DRA to a broader auction platform without first addressing the competitive position of DR resources *vis a vis* generators and other sources of capacity would unnecessarily damage a highly successful existing market mechanism, which would be unfair to DR resources, counterproductive to robust evolution of the Ontario electricity market, and irresponsible on the part of the IESO.

Failing to recognize and compensate the value of DR resources to the energy market is unjust and unreasonable.

29. It has been definitively recognized that DR resources can provide electricity wholesale market energy services, and that failure to compensate DR resources for such services is unjust and unreasonable.

30. In a Final Rule issued in March, 2011 the United States Federal Energy Regulatory Commission (FERC) determined that:[14]

> *… when a demand response resource participating in an organized wholesale energy market… has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective… that demand response resource must be compensated for the service it provides to the energy market at the market price for energy…*

[12] Energy payments avoided by the load are not economically equivalent to energy payments for provision of demand reduction to the market, and are not adequately compensatory for the value provided by DR resources to the energy market: 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, paragraph 62.
[13] IESO Demand Response Working Group Meeting Materials, June 19, 2019, pages 36 *et seq*.
[14] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, page 1.

This approach for compensating 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.

31. The FERC's conclusions on this topic followed a comprehensive rule making process during which opposing positions on the issue were thoroughly represented (with supporting expert evidence), canvassed and considered.

32. On January 25, 2016, the Supreme Court of the United States issued a determination that in making the foregoing determination FERC was within its jurisdiction to regulate wholesale power markets. While expressly eschewing making a finding on the correctness of FERC's determination as outside of the Court's legitimate area of inquiry, following a detailed 33 page review of the evidence and arguments placed before FERC in the rule making process, the Court commented:[15]

Our important but limited role is to ensure that the Commission engaged in reasoned decision making – that it weighed competing views, selected a compensation formula with adequate support in the record, and intelligibly explained the reasons for making that choice. FERC satisfied that standard.

33. FERC's determination that establishing just and reasonable wholesale power market rates requires that a DR resource must be compensated for the service it provides to the energy market at the market price for energy was subject to satisfaction of a "net benefits test" to assess the appropriateness of that DR compensation. The "net benefits test" condition was applied to address what was referred to in the FERC's rule making proceeding as the "billing unit effect" of dispatching DR resources in the energy market. Essentially, the concern is that as the volume of energy consumed declines when DR resources actually reduce demand (i.e. avoid consuming energy), the reduction in the costs to meet overall energy demand by dispatching competitive DR is offset in end-user rates to some extent by the fewer units consumed, resulting in an upward pressure in the price for each unit. Whether the reduced costs of supply outweigh the upward pressure on unit rates determines whether there is a "net benefit" for end-users from participation of the DR resource in the market. If there is, then it is in the interest of consumers that DR resources be dispatched when they require a lower energy payment than other resources bidding into the market.

34. On this point FERC concluded as follows[16]:

For this reason, the billing unit effect associated with dispatch of a demand response resource in an energy market must be taken into account in the economic comparison of the energy bids of generation resources and demand response resources. Therefore, rather than requiring compensation at [marginal price] in all hours, the Commission requires the use of the net benefits test described herein to ensure that the overall benefit of reduced [marginal price] that results from dispatching demand response resources exceeds the cost of

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[15] Federal Energy Regulatory Commission v. Electric Power Supply Association Et Al., 577 U.S. (2016), page 33.
[16] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, paragraph 53.

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 [marginal price] for services provided, as do generation resources.

35. In the course of its consideration of the equivalency of DR resources and generation resources in providing energy services, the importance of recognizing and compensating this equivalency appropriately, and the importance of thus reducing barriers to DR participation in wholesale markets, FERC cited an earlier order which included a finding that[17]:

> *A market functions effectively only when both supply and demand can meaningfully participate, and barriers to demand response limit the meaningful participation of demand in electricity markets.*

36. FERC went on to find that:

> *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.*[18]
>
> *…*
>
> *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."*[19]

37. In its rulemaking deliberations FERC also considered arguments that DR resources are "compensated" by avoiding energy costs when responding to requests to curtail consumption, and accordingly paying such resources for energy thereby effectively supplied would amount to double compensation. On these arguments FERC found as follows:[20] [emphasis in original]

> *Furthermore, Dr. [Alfred E.] Kahn argues that paying demand response [marginal price] sets "up an arrangement that treats proffered reductions in demand on a competitive par with positive supplies; but one is no more a [case of overcompensation]*[21] *than the other: the one delivers electric power to users at marginal costs – the other –* <u>*reductions in cost*</u> *– both at competitively-determined levels.*
>
> *… 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,*

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[17] Ibid, paragraph 57, citing FERC Order No. 719.
[18] Ibid, paragraph 59.
[19] Ibid, paragraph 61.
[20] Ibid, paragraph 62.
[21] Insert in original.

as requested by some commenters, single out demand response resources for adjustments to compensation. The Commission has long held that payment of [marginal price] to supply resources clearing 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. Commenters have not justified why it would be appropriate for the Commission to continue to apply this approach to generation resources yet depart from this approach for demand response resources.

38. FERC also recognized in its rule making findings the interrelationship between just and reasonable compensation to DR resources in energy markets and the fairness of associated capacity markets. FERC noted *"how the increased participation by demand resources [in energy markets] could actually increase potential suppliers in capacity markets by reducing barriers to demand resources, which would tend to drive capacity prices down"*, and the need to *"examine the way in which capacity markets already may take into account energy revenues"*.[22]

Instituting a TCA without resolving issues regarding just and reasonable compensation to DR resources is discriminatory.

39. As outlined above, the pre-eminent North American energy regulator – FERC – has carefully and thoroughly considered the role of DR resources in wholesale energy markets, and the issue of just and reasonable compensation of those resources for their participation, and has concluded that:

    (a) Failure to compensate DR resources for the value they provide to energy markets in the same manner as compensation is afforded to generation resources for the value which they supply to energy markets results in wholesale prices that are unjust and unreasonable.

    (b) Fair compensation of wholesale energy market participants for energy services provided influences the fairness and efficiency of capacity markets.

40. It follows that expanding the current DRA platform to allow generation resources eligible for energy market compensation to participate in the broadened capacity auction without addressing just and reasonable compensation for DR resources providing energy market services would result in capacity markets that are effectively anti-competitive and discriminatory.

41. Without resolution of payment to DR resources for energy services that they can and do provide to the energy market in a manner that fairly recognizes the value of these services provided, inviting generators to compete with DR resources in a capacity auction would unduly and unfairly prejudice the ability of those DR resources to compete, and would thus be discriminatory.

[22] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, page 67, footnote 167.

Market Rule Amendments which, in the result, are discriminatory, must be rejected.

42. The Ontario *Electricity Act, 1998* (*EL Act*) governs the authority of the IESO to make Market Rules, and the manner in which the Ontario Energy Board (OEB) oversees that IESO authority.

43. Subsection 33(9) of the *EL Act* requires the OEB to consider whether a Market Rule amendment *“unjustly discriminates against or in favour of a market participant or class of market participants”*. If the OEB so finds, it must make an order revoking the amendment, and referring the amendment back to the IESO for further consideration.

44. For the reasons articulated above, Market Rule amendments which have the effect of allowing generation resources to unjustly and unfairly compete against DR resources for the provision of capacity to the IAM would *“unjustly discriminate against a class of market participants”* – i.e. DR resources currently active in the very successful DRA – and would have to be revoked by the OEB.

45. The IESO should refrain from instituting Market Rule amendments which would co-opt the current DRA platform to a broadened capacity auction prior to addressing the currently unjust and unreasonable wholesale energy market compensation structure under which DR resources are not fairly and properly compensated for the energy services which they provide to the IAM.

46. To proceed with the TCA related Market Rule amendments proposed without first addressing this unfairness would have the effect of unjustly discriminating against DR resources competing to provide capacity to the IAM. Such amendments would not withstand regulatory review.

Recommendation.

47. The unjust discrimination outlined above would be particularly objectionable where there is no need to rush to ICA implementation prior to resolution of the issue of just and reasonable compensation for DR resources in the wholesale energy market. With the suspension of work on the ICA as a result of an updated forecast which sees no resource constraints for the foreseeable future there is no justification for rushing to TCA implementation.

48. AEMA and AMPCO support expansion of the current DRA into a broader capacity auction platform, and the use of a broadened capacity auction platform along with other competitive procurement options to address future capacity needs.

49. While AEMA/AMPCO recognize that the IESO has now proposed a study, to be completed by the end of 2020, to determine *“whether there is a net benefit to electricity ratepayers if DR resources are compensated with energy payments for economic activations”*, as outlined above the FERC has already exhaustively considered this issue as recognized by the U.S. Supreme Court, and has unequivocally concluded “yes”. Repeating this comprehensive examination is unnecessary and wasteful. That work has already been done, and concluded.

50. A more appropriate, and considerably more focussed, inquiry to validate the "net benefits" to consumers should not take until the end of 2020.

51. In order to enhance competition and market confidence, both to the ultimate benefit of Ontario's electricity consumers, **AEMA and AMPCO urge the IESO to:**

(a) **Recognize and respect both its own overall MRP objectives and its capacity auction specific objectives of *"[c]reating a stable and efficient marketplace that produces value for consumers"* by *"encouraging competition and innovation among suppliers"* and *"resolv[ing] long-standing market design issues"*[23].**

(b) **Proceed expeditiously with a more focussed study to validate the "net benefits" to consumers of energy payments for DR resources, so that the study can be concluded as soon as feasible and its results implemented.**

(c) **Defer implementation of a TCA from December, 2019 and instead focus on getting the proposed TCA right from its initiation, following resolution of the issue of compensation of DR resources for the value that they provide to the IAM.**

(d) **Thereby avoid a result which would unfairly and unjustly discriminate against DR resources in the IAM.**

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[23] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 1.

TAB 26

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.

<table>
<tr><td>Reinmuller, Robert

Representing:
Transmitters</td><td>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.</td></tr>
<tr><td>Samant, Sushil

Representing:
Market Participant Generators</td><td>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)
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).</td></tr>
</table>

	o The IESO has agreed to further stakeholder the use of Utilization Payments for in-market or economic activations of all Demand Response (DR) resources. o 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). o 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 27

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 28

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

PART 6 – REASONS

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 29

Help

Capacity Auction: Pre-Auction Report

Created at Sep 26, 2019 10:36:55

Transitional Capacity Auction Periods

Commitment Period	Season	Obligation Period
May 01, 2020 - Apr 30, 2021	Summer	May 01, 2020 - Oct 31, 2020
	Winter	Nov 01, 2020 - Apr 30, 2021

Transitional Capacity Auction Key Milestones

Milestone	Due Date
CAP to start and complete capacity qualification (including posting auction deposit)	Oct 15, 2019 - Nov 27, 2019
CAP to submit Transitional Capacity Auction offers	Dec 04, 2019 - Dec 05, 2019
IESO to publish Transitional Capacity Auction post auction report	Dec 12, 2019

Transitional Capacity Auction Parameters

Demand Curve Elements	Summer Obligation Period	Winter Obligation Period
	(May 01, 2020 - Oct 31, 2020)	(Nov 01, 2020 - Apr 30, 2021)
Target Capacity (MW)	675	675
Transitional Capacity Auction Reference Price ($/MW-day)	413	413
Minimum Transitional Capacity Auction Clearing Price ($/MW-day)	0	0
Maximum Transitional Capacity Auction Clearing Price ($/MW-day)	516	516
Minimum Auction Capacity Limit (MW)	0	0
Maximum Auction Capacity Limit (MW)	1215	1215
Maximum Auction Capacity at the Maximum Transitional Capacity Auction Clearing Price (MW)	540	540

IESO Electrical Zones Mapping

IESO Zonal Map Tool

Zonal Constraints

Zone	Summer Obligation Period (May 01, 2020 - Oct 31, 2020)			Winter Obligation Period (Nov 01, 2020 - Apr 30, 2021)		
	Total Zonal Capacity Limit Minimum (MW)	Total Zonal Capacity Limit Maximum (MW)	Virtual Zonal Capacity Limit Maximum (MW)	Total Zonal Capacity Limit Minimum (MW)	Total Zonal Capacity Limit Maximum (MW)	Virtual Zonal Capacity Limit Maximum(MW)
BRUCE	0	100	100	0	100	100
EAST	0	9999*	305	0	9999*	305
ESSA	0	9999*	100	0	9999*	100
NIAGARA	0	35.1	20.2	0	35.1	20.2
NORTHEAST	0	66.2	63.2	0	66.2	63.2
NORTHWEST	0	56.1	2.1	0	56.1	2.1
OTTAWA	0	9999*	126.9	0	9999*	126.9
SOUTHWEST	0	9999*	287	0	9999*	287
TORONTO	0	9999*	383.2	0	9999*	383.2
WEST	0	69.8	69.8	0	69.8	69.8

*** The value "9999" means there is no Zonal Capacity Limit associated with the zone, but the Maximum Auction Capacity Limit applies.**