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December 21, 2016

VIA RESS AND COURIER

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Ms. Walli:

RE: EB-2016-0160 Hydro One Networks Inc. ("Hydro One") Transmission Rates Application – Responses to Undertakings J10.1, J9.9, J12.6, J12.7, J12.8, J12.9B and J12.9A

Hydro One's responses to Undertakings J10.1, J9.9, J12.6, J12.7, J12.8, J12.9B and J12.9A are enclosed.

Yours truly,

McCarthy Tétrault LLP
Per:

For: Gordon M. Nettleton

GMN

UNDERTAKING – J10.1

Undertaking

To update K9.7 if required.

Response

Exhibit K 9.7 (Corrected)

HONI Compensation and Complement 2013-2018 (Transmission)
(Source:Ex.C1-4-1 Att. 1)

	PWU Reg. Complement	YOY % Change Complement	Cumulative Change Complement	PWU TX Total Wages	YOY % Change Wages	Cumulative % Change Wages	Average Annual Change in Wages
2013	3321	0	0	$246,845,648	0	0	
2014	3271	-1.51%	-1.51%	$267,903,386	8.53%	8.53%	
2015	3350	2.42%	0.87%	$266,458,363	-0.54%	7.95%	
2016	3411	1.82%	2.71%	$251,591,352	-5.58%	1.92%	
2017	3319	-2.70%	-0.06%	$270,529,781	7.53%	9.59%	
2018	3278	-1.24%	-1.29%	$261,296,861	-3.41%	5.85%	1.14%

	SEP Reg. Complement	YOY % Change Complement	Cumulative Change Complement	SEP TX Total Wages	YOY % Change Wages	Cumulative % Change Wages	
2013	1260	0	0	$101,120,821	0	0	
2014	1290	2.38%	2.38%	$114,374,026	13.11%	13.11%	
2015	1285	-0.39%	1.98%	$113,480,871	-0.78%	12.22%	
2016	1241	-3.42%	-1.51%	$102,812,746	-9.40%	1.67%	
2017	1212	-2.34%	-3.81%	$110,170,524	7.16%	8.95%	
2018	1177	-2.89%	-6.59%	$105,512,289	-4.23%	4.34%	0.85%

	MCP Reg. Complement	YOY % Change Complement	Cumulative Change Complement	MCP TX Total Wages	YOY % Change Wages	Cumulative % Change Wages	
2013	600	0	0	$62,833,601	0	0	
2014	584	-2.67%	-2.67%	$63,045,596	0.34%	0.34%	
2015	585	0.17%	-2.50%	$63,576,452	0.84%	1.18%	
2016	596	1.88%	-0.67%	$64,599,092	1.61%	2.81%	
2017	593	-0.50%	-1.17%	$68,808,583	6.52%	9.51%	
2018	587	-1.01%	-2.17%	$69,157,078	0.51%	10.06%	1.94%

Witness: Keith McDonell

	Casual Complement	YOY % Change Complement	Cumulative Change Complement	Casual TX Total Wages	YOY % Change Wages	Cumulative % Change Wages	
2013	1781	0	0	$49,836,709	0	0	
2014	1951	9.55%	9.55%	$60,490,424	21.38%	21.38%	
2015	1819	-6.77%	2.13%	$57,326,198	-5.23%	15.03%	
2016	1971	8.36%	10.67%	$61,484,240	7.25%	23.37%	
2017	2106	6.85%	18.25%	$69,994,263	13.84%	40.45%	
2018	2158	2.47%	21.17%	$69,942,576	-0.07%	40.34%	7.01%

1

	Total HONI Complement	YOY % Change Complement	Cumulative Change Complement	HONI TX Total Wages	YOY % Change Wages	Cumulative % Change Wages	
2013	7228	0	0	$476,042,503	0	0	
2014	7336	1.49%	1.49%	$522,547,669	9.77%	9.77%	
2015	7283	-0.72%	0.76%	$517,129,026	-1.04%	8.63%	
2016	7526	3.34%	4.12%	$498,983,983	-3.51%	4.82%	
2017	7525	-0.01%	4.11%	$539,347,645	8.09%	13.30%	
2018	7489	-0.48%	3.61%	$525,558,154	-2.56%	10.40%	2.00%

2

UNDERTAKING – J9.9

Undertaking

To provide the 2013 to 2016 overtime hours in the budget.

Response

During the business planning process, an estimate of the forecasted overtime is derived from the historical overtime hours. Due to a new business planning tool being implemented in 2013, available forecasted overtime hours is limited to 2013 and subsequent years.

To estimate the forecasted hours for the transmission business, the ratio of the Tx: Dx ratio of total overtime hours was used.

Year	**Planned TX Overtime (hours)**
2013	329,808
2014	470,386
2015	428,564
2016	377,194

Witness: Keith McDonell

UNDERTAKING – J12.6

Undertaking

To produce revised energy figures based on those in the Ontario Planning Outlook.

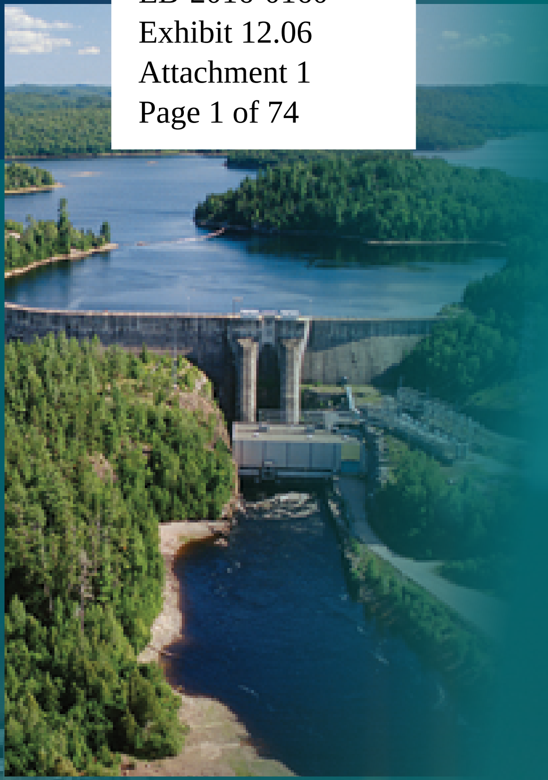
Response

The Ontario Planning Outlook (September 2016) provides the latest IESO energy savings figure for Conservation for 2014, which is 11.3 TWh. This is greater than the corresponding value of 10.1 TWh from the LTEP 2013. The Ontario Planning Outlook is provided as Attachment 1. (The updated 2014 value is included in the table titled "Data for Figure 3: Historical Ontario Energy Demand"on page 7 of the *Data Tables for the OPO Technical Report* included therein.)

In its cross-examination on conservation energy savings, VECC introduced a page from the IESO's December 2015 report "LTEP: Comparison of 2014 Forecast vs. 2014 Actual Results" (page 14 of Exhibit K12.6). A link to this same report was provided in part a) of Exhibit I, Tab 12, Schedule 28. For completeness of the record, and given that Mr. Alagheband referenced page 8 of this same report in his testimony, the full IESO report is provided as Attachment 2 to this response.

Witness: Bijan Alagheband

Filed: 2016-12-21
EB-2016-0160
Exhibit 12.06
Attachment 1
Page 1 of 74



Ontario Planning Outlook

A technical report on the electricity system prepared by the IESO

SEPTEMBER 1, 2016

ieso
Connecting Today.
Powering Tomorrow.

Table of Contents

Foreword

1

This report responds to the June 10, 2016 request from the Minister of Energy for a technical report from the Independent Electricity System Operator (IESO) pursuant to Section 25.29 (3) of the *Electricity Act, 1998* on the adequacy and reliability of Ontario's electricity resources in support of the development of the Long-Term Energy Plan (LTEP) (see Appendix A). This report presents the IESO's planning outlook for the 2016 through 2035 period and includes a range of demand outlooks.

Looking forward, Ontario's electricity system is well positioned to continue to meet provincial needs, while at the same time adapting to significant change across the sector. Over the past decade, the coal fleet has been retired and replaced with wind, solar, bioenergy, waterpower, refurbished nuclear and natural gas-fired resources. These resources, combined with investments in conservation and transmission:

- have addressed the reliability concerns of a decade ago
- have reduced greenhouse gas emissions in Ontario's electricity sector by more than 80 percent
- with current planned investments, will help to meet the province's needs well into this planning period.

Implementation of the province's climate change policies, consistent with the Climate Change Action Plan, the *Climate Change Mitigation and Low-Carbon Economy Act, 2016*, and the *Vancouver Declaration,* will have an impact on the demand and supply of electricity including through greater electrification of the economy.

This report begins with an overview of the current state of Ontario's electricity system. As per the Minister's request, it also examines the outlook for demand; the potential for resources such as conservation, wind, solar, bioenergy, waterpower, and nuclear, as well as new emerging distributed energy resources to meet that demand; the risks associated with those various resources; and the costs of the electricity system. The report looks at the needs of the electricity system over the next two decades associated with capacity, reliability, market and system operations, transmission and distribution. It also provides an outlook for emissions from the electricity sector.

The State of the System: 10-Year Review

2

Investments over the last decade have established a firm foundation for Ontario's electricity system. Between 2005 and 2015, the province saw a net growth in electricity supply: over six gigawatts (GW) of installed coal-fired capacity was shut down and replaced with more than 14 GW of renewable, natural gas-fired, nuclear and demand response resources (Figure 1). This has driven a significant change in the province's electricity supply mix, with the share from fossil-fuelled resources decreasing while the share of supply from non-fossil-fuelled resources increased.

Renewable energy now comprises 40 percent of Ontario's installed capacity and generates approximately one-third of the electricity produced in the province. When combined with nuclear resources, which account for one-third of Ontario's installed capacity and produce nearly 60 percent of its electricity, these non-fossil sources now generate approximately 90 percent of the electricity in Ontario (Figure 2).

While the electricity system has traditionally been characterized by the flow of electricity from large central generating stations through bulk transmission lines to load centres, the last decade saw an increasing amount of generation embedded within the province's distribution systems. Distributed energy resources typically include renewable resources such as solar, wind, waterpower or bioenergy or combined heat and power (CHP) facilities and demand response (DR) resources. Supply from embedded resources connected to the distribution system was negligible in 2005. But by the end of 2015, the amount of embedded resources had grown to approximately 3,600 megawatts (MW) of installed supply.[2]

Demand measured on the province's bulk power grid has declined over the last 10 years (Figure 3) as a result of conservation, distributed energy resources, changes in the economy and pricing effects. Non-weather-corrected grid demand in Ontario was approximately 10 percent lower in 2015 than it was 10 years previously, dropping from 151 terawatt-hours (TWh) in 2006 to

Figure 1: Ontario Installed Supply Mix in 2005 and 2015

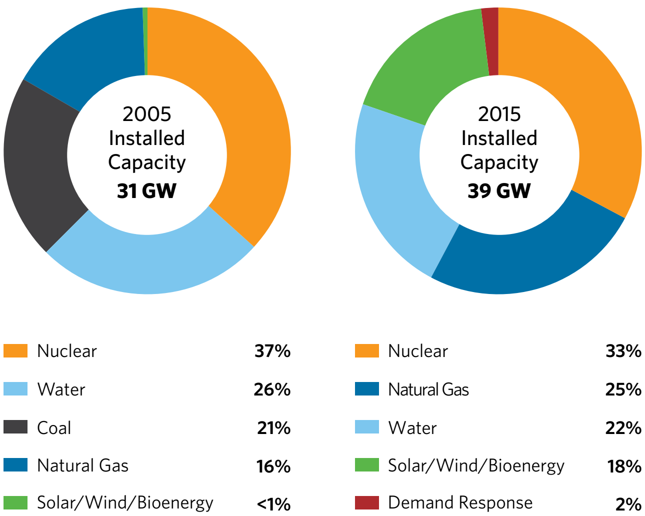
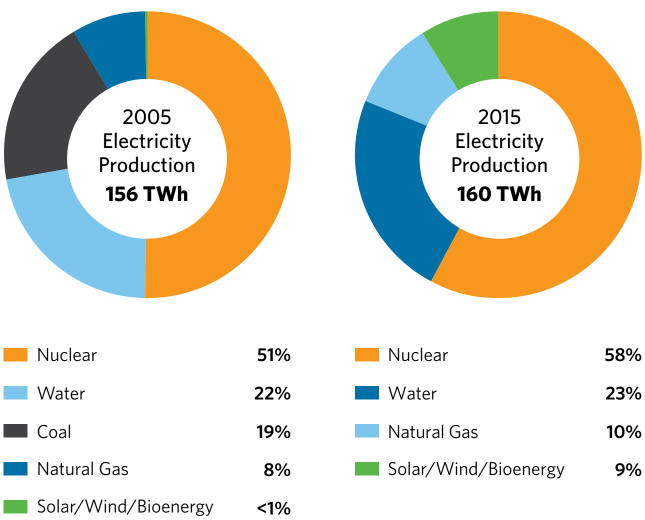


Figure 2: Ontario Electricity Production in 2005 and 2015[1]



[1] Includes electricity produced to meet Ontario demand, including embedded generation (which brings the total to 143 TWh in 2015), and exports (17 TWh in 2015).

[2] Embedded resources are small-scale supply resources located within the distribution system and are not part of the IESO-controlled grid. At the end of 2015, there were approximately 2,900 MW of embedded generation (mostly solar PV) and 700 MW of embedded demand response resources.

Figure 3: Historical Ontario Energy Demand[3]

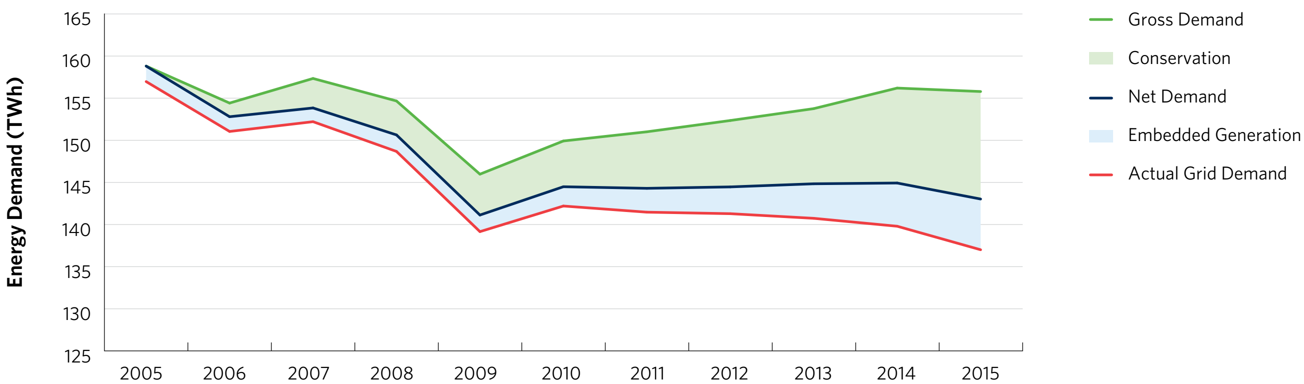


Figure 4: Conservation Savings in 2015

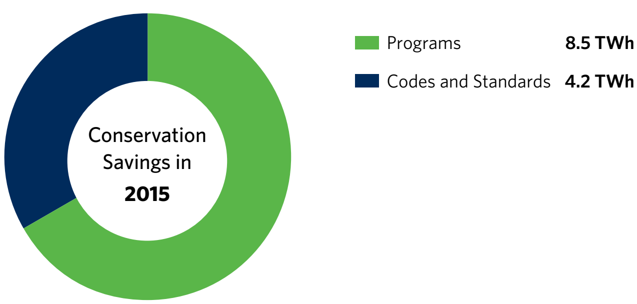
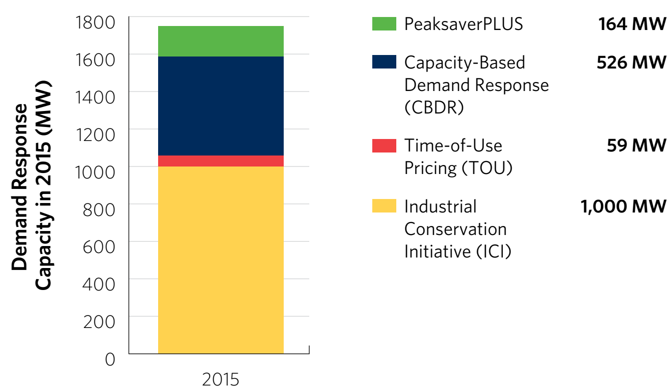


Figure 5: Demand Response Capacity in 2015



137 TWh in 2015. As a result of the additional supply and reduction in demand, there has been a sizeable appreciation of Ontario's capacity margins, and the capacity deficits that existed in the early 2000s have been eliminated.

Conservation and demand management played an increasing role in reducing both energy and peak demands over the 2006-2015 period, with the province achieving 12.7 TWh of electricity savings through conservation programs and changes to codes and standards (Figure 4).[4]

Demand response initiatives have combined to reduce peak demand on summer days. The grid peak demand of 27,005 MW on August 1, 2006 continues to be the all-time highest provincial grid peak demand. By comparison, the grid peak demand in 2015 was 22,516 MW.[5] The IESO has introduced demand response into the market where it can be called upon like other resources to meet provincial needs. The first capacity-based demand response auction conducted in December 2015 is contributing 391.5 MW for the 2016 summer season and 403.7 MW for the 2016-17 winter season. Demand response resources together amounted to approximately 1.8 GW in 2015 (Figure 5).

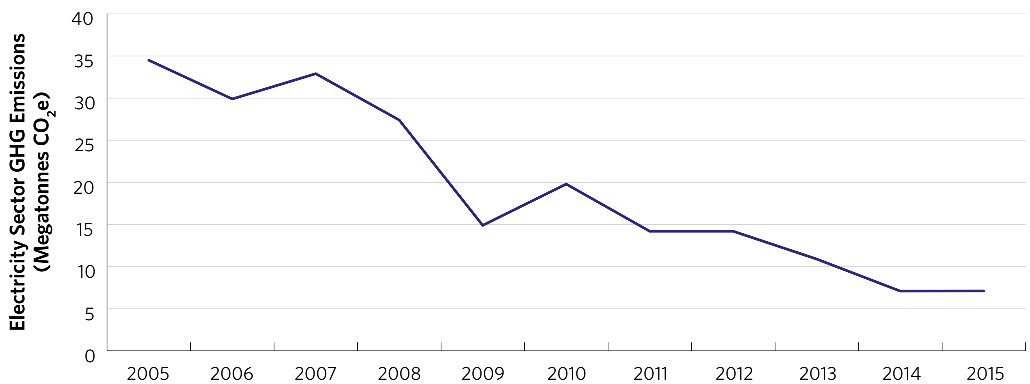
The operability of the system has also evolved over the past decade. In response to surplus baseload generation conditions, the IESO has enhanced its processes to maintain supply-demand balance through dispatching down grid-connected wind and solar facilities and manoeuvering nuclear units. The IESO's Renewable Integration Initiative (RII) introduced centralized resource forecasting to help

[3] "Grid demand" is delivered on the bulk system to wholesale customers and local distribution customers. "Net demand" is the grid demand plus output from embedded resources on the distribution system. "Gross demand" is the need for electricity prior to the effects of conservation and reflects net demand with conservation savings added back to it.

[4] 2015 conservation results have not yet been verified.

[5] Weather-corrected net peak demand in 2006 was 25,162 MW and in 2015 was 23,965 MW. All demand outlooks presented in this report refer to weather-corrected net peak demand unless described otherwise.

Figure 6: Electricity Sector GHG Emissions[6]



reduce forecast errors for variable generation. The IESO also started to explore the use of storage and demand response to provide regulation services.

Due to the retirement of coal-fired generation and the reduced demand for electricity, the greenhouse gas (GHG) emissions from Ontario's electricity sector has fallen by 80 percent since 2005 (Figure 6). Carbon emissions from the electricity sector now make up approximately four percent of the province's total emissions or approximately seven megatonnes of GHG emissions in 2015.

"Due to the retirement of coal-fired generation and the reduced demand for electricity, the greenhouse gas (GHG) emissions from Ontario's electricity sector fell by 80 percent since 2005."

The evolution over the past decade in the amount and nature of Ontario's electricity supply was supported by increased investment in transmission. This investment served several purposes: facilitating Ontario's off-coal policy, enabling the incorporation of new renewable energy resources, enhancing the reliability of the power system across the province and expanding access to neighbouring electricity markets.

In real terms, the total cost of electricity service grew by 32 percent between 2006 and 2015, primarily because of new investments in generation and distribution infrastructure.[7] The cost is now approximately $20 billion per year in current dollars. Over the same period, reductions in overall demand increased the average unit cost of electricity in real terms by 3.9 percent per year; it is now approximately $140 per megawatt-hour (MWh) in current dollars. As described in Section 3.7, these unit costs are expected to stabilize through the planning period.

[6] 2015 emissions are estimated.

[7] 2005 was an anomalous year due to unusual weather and tight supply conditions which led to very high demand and record market prices for power.

Electricity System 20-Year Outlook

3

3.1. Demand Outlook

The demand for electricity is the starting point used in assessing the outlook for the electricity system. There is uncertainty in any demand outlook, as future demand will depend on the economy, demographics, policy and other considerations (Figure 7). Electricity planning explicitly recognizes the uncertainties in any of these drivers by addressing a range of potential futures.

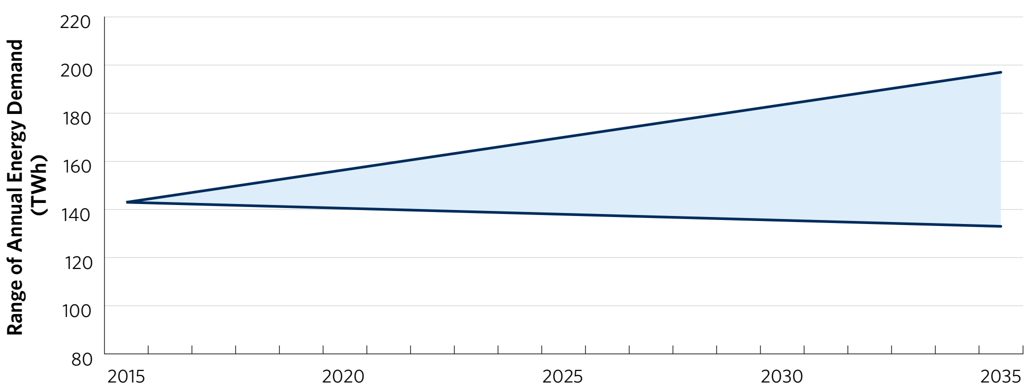
In preparing this report, the IESO considered a range for electricity demand in Ontario, from 133 TWh to 197 TWh in 2035, compared to 143 TWh in 2015 (Figure 8). This range is reflected in four outlooks that provide context for long-term integrated planning and discussion. The outlooks all reflect the actions identified in the government's recently announced Climate Change Action Plan.[8]

The four outlooks for Ontario's electricity demand are:

- Outlook A (or "low demand outlook"), which explores the implications of lower electricity demand
- Outlook B (or "flat demand outlook"), which explores a level of long-term demand that roughly matches the level of demand that exists today
- Outlooks C and D (or "higher demand outlooks"), which explore higher levels of demand driven by different levels of electrification associated with policy choices on climate change.

The peak demand in the summer differs in the four outlooks, from 22.6 GW to 28.5 GW by 2035 (Figure 9). The winter peak ranges from 20.6 GW to 35.4 GW (Figure 10). Outlooks C and D would see Ontario return to being a winter-peaking jurisdiction as a result of an increased use of electricity for space heating.

Figure 7: Demand Uncertainty



[8] Ontario Climate Change Action Plan (June 2016) https://www.ontario.ca/page/climate-change-action-plan

Figure 8: Ontario Net Energy Demand across Demand Outlooks

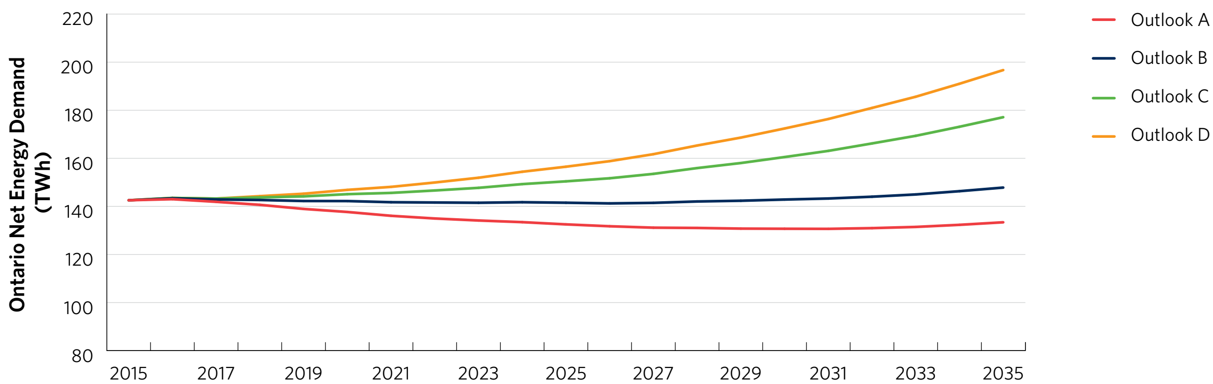


Figure 9: Ontario Net Summer Peak Demand across Demand Outlooks

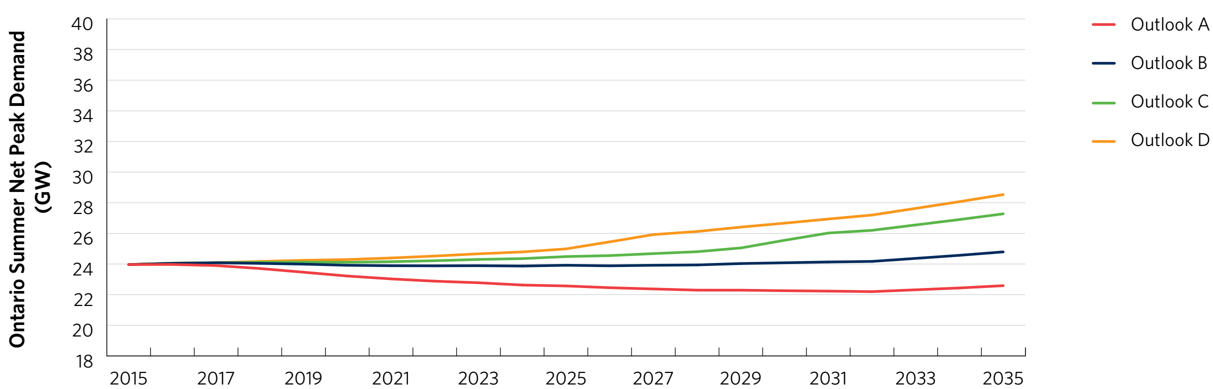


Figure 10: Ontario Net Winter Peak Demand across Demand Outlooks

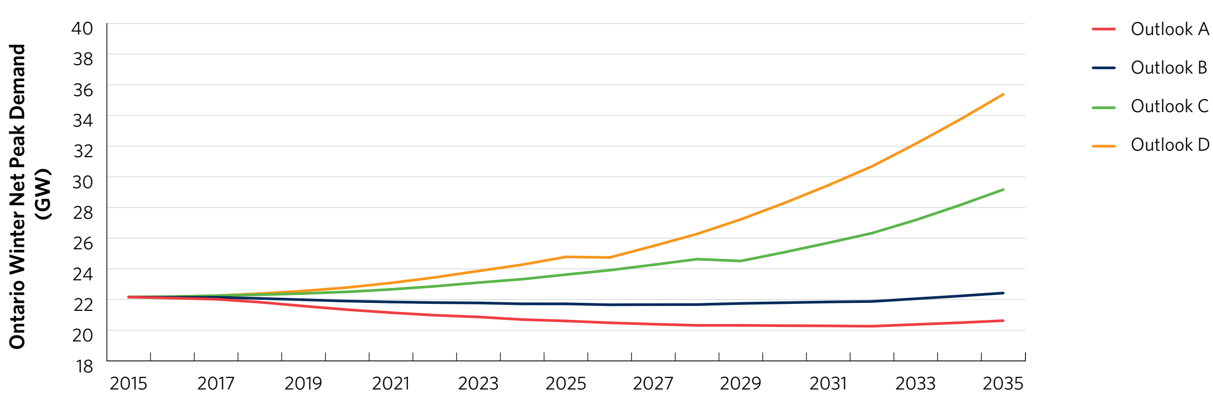


Table 1: Assumptions across Demand Outlooks

Sector	Outlook A	Outlook B	Outlook C	Outlook D
Residential (52 TWh in 2015)	48 TWh in 2035	51 TWh in 2035	Oil heating switches to heat pumps, electric space and water heating gain 25% of gas market share (58 TWh in 2035)*	Oil heating switches to heat pumps, electric space and water heating gain 50% of gas market share (64 TWh in 2035)
Commercial (51 TWh in 2015)	49 TWh in 2035	54 TWh in 2035	Oil heating switches to heat pumps, electric space and water heating gain 25% of gas market share (63 TWh in 2035)	Oil heating switches to heat pumps, electric space and water heating gain 50% of gas market share (69 TWh in 2035)
Industrial (35 TWh in 2015)	29 TWh in 2035	35 TWh in 2035	5% of 2012 fossil energy switches to electric equivalent (43 TWh in 2035)	10% of 2012 fossil energy switches to electric equivalent (51 TWh in 2035)
Electric Vehicles (<1 TWh in 2015)	2 TWh in 2035	3 TWh in 2035	2.4 million electric vehicles (EVs) by 2035 (8 TWh in 2035)	2.4 million EVs by 2035 (8 TWh in 2035)
Transit (<1 TWh in 2015)	1 TWh in 2035	1 TWh in 2035	Planned projects, 2017-2035 (1 TWh in 2035)	Planned projects, 2017-2035 (1 TWh in 2035)
Other**	5 TWh	5 TWh	5 TWh	5 TWh
Total* (143 TWh in 2015)**	**133 TWh in 2035**	**148 TWh in 2035**	**177 TWh in 2035**	**197 TWh in 2035**

Note: Outlooks C and D assume the same economic drivers as Outlook B.

* By 2035, of the number of natural gas-fuelled space and water heating equipment being sold in Outlook B (due to existing equipment reaching end of life and new additions driven by growth in the residential and commercial sectors), 25 percent of this stock in Outlook C and 50 percent in Outlook D is replaced with air-source heat pumps.

** "Other" represents demand from agriculture, remote communities, generator demand, the Industrial Electricity Incentive (IEI) program and street lighting.

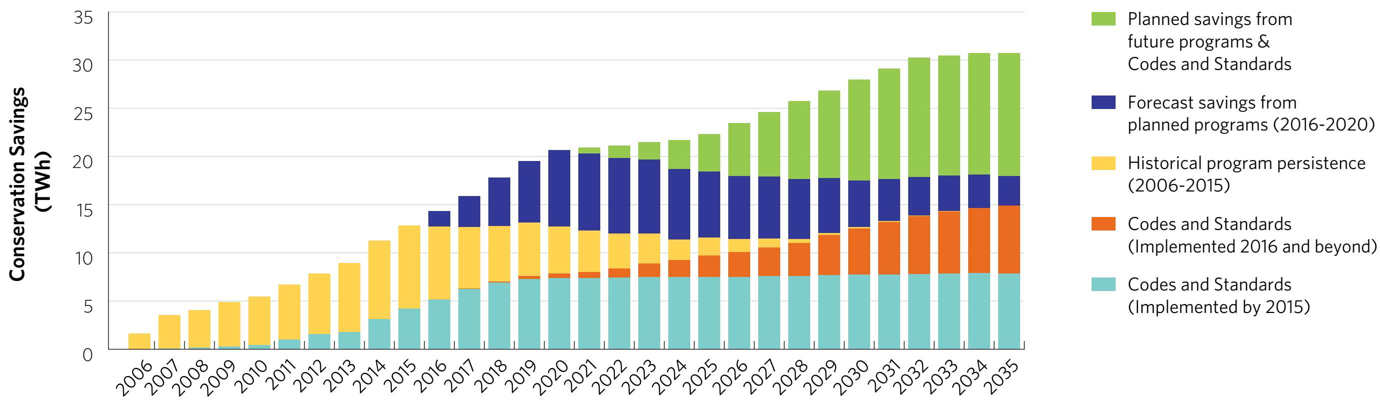
*** Total may not add up due to rounding.

Assumptions across the demand outlooks are summarized in Table 1.

In June 2016, the government released its Climate Change Action Plan (CCAP), which includes a number of policy objectives to encourage reductions in the use of fossil fuels in Ontario. Electrification potential exists in nearly every part of the energy system. Electrification of the transportation sector has been garnering much attention over the last few years with its potential to be an economical and clean alternative to fossil-fuel powered engines. Potential also exists for fuel switching in other sectors, particularly where oil or natural gas is the primary fuel.

The early focus of the CCAP is on programs over the next five years, although it is anticipated that the CCAP will be regularly updated. Each of the four demand outlooks in this report reflects the impacts that near-term actions in the CCAP would have on the electricity sector. In the longer term, there is uncertainty with respect to the pace of electrification.

Figure 11: Conservation Achievement and Outlook to Meet the 2013 LTEP Target



3.2. Conservation Outlook

All four outlooks incorporate the achievement of the target established in 2013 LTEP of 30 TWh by 2032 and the near-term target set in the Conservation First Framework and Industrial Accelerator Program of 8.7 TWh by 2020. The long-term target is achieved through a combination of conservation programs and building codes and equipment standards (Figure 11). Approximately 60 percent of this is expected to be achieved through programs implemented to date, those programs that are a part of the current Conservation First Framework, and codes and standards. To achieve the longer-term target, it is assumed that conservation programs will continue to be made available to customers after the Conservation First Framework ends. The focus and design of future programs will be determined based on future sector and market conditions and on the experience gained in the current framework.

In June 2016, the IESO completed an Achievable Potential Study (APS) to assess the electricity conservation potential in Ontario. The APS considered the potential for energy-efficiency programs and for behind-the-meter generation projects. The APS concluded that within the current budget assumptions, approximately 7.4 TWh of conservation can be achieved by local distribution companies (LDCs) by 2020. The APS also found that in the longer term about 19 TWh can be achieved from distribution- and transmission-connected customers by 2035. Incremental conservation may be achievable at higher budget levels. The APS considered conservation measures and technologies that are currently feasible. It is likely that new and possibly disruptive technologies will become available and will change the outlook for conservation achievement. The IESO will continue to update its assessments in order to understand conservation potential for integration into future plans.

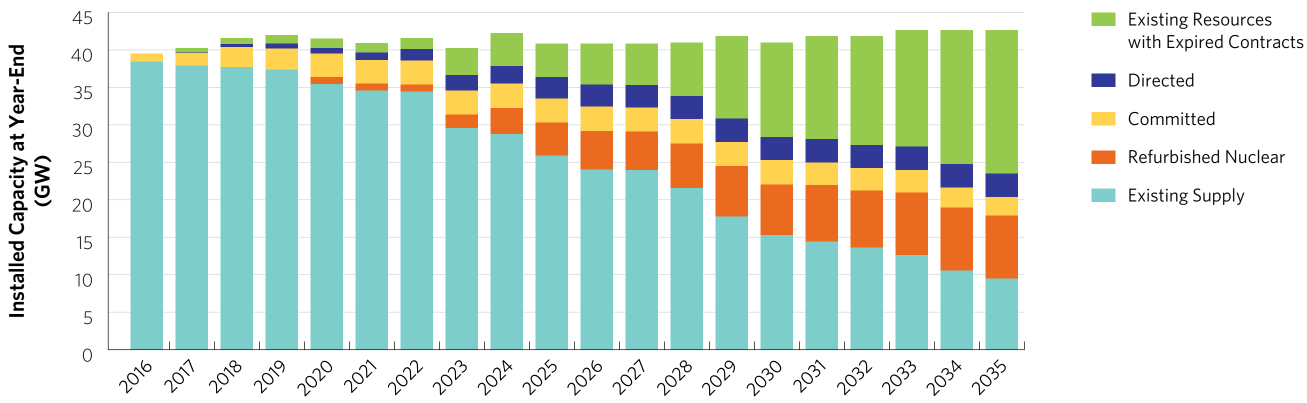
Opportunities for conservation will also vary with increases and decreases in demand. In the higher demand outlooks, demand growth is assumed to come from the electrification of key end uses such as space heating and water heating. In developing these outlooks, the IESO assumed that customers would switch from oil and natural gas to efficient electric technologies such as air-source heat pumps. As such, a considerable amount of incremental conservation has been assumed to occur in these outlooks. There may be some opportunity for conservation beyond that already assumed as the value of conservation will be higher than in the flat demand outlook, particularly in the period following 2025 as new resources are required to meet demand. The nature of programs in these outlooks would need to focus on meeting winter peak requirements. However, more study is required to identify incremental conservation potential under different demand outlooks.

3.3. Supply Outlook

As previously discussed, Ontario is in a strong starting position to reliably address any of the demand outlooks presented in this report. This starting position is shaped by three factors:

- The combined capability of resources that exist today ("existing resources")
- Resources that have been procured but are not yet in service ("committed resources")
- Resources not yet procured or acquired but have been directed to meet government policy objectives outlined in the 2013 LTEP and elsewhere ("directed resources")

Figure 12: Outlook for Installed Capacity to 2035



If all existing resources were to continue to operate after the expiry of their contracts, and if nuclear refurbishments, committed resources and directed resources come into service as scheduled, Ontario would have a total installed capacity of nearly 43 GW by 2035 (Figure 12). In contrast, if all existing resources are removed from service after contract expiry, Ontario would have a total installed capacity of approximately 25 GW by 2035.

There are a number of risks that could affect the availability of supply over the planning outlook. This includes the risk of implementation delays, including with the nuclear refurbishment program, and the effect of aging on the performance of the generation fleet.

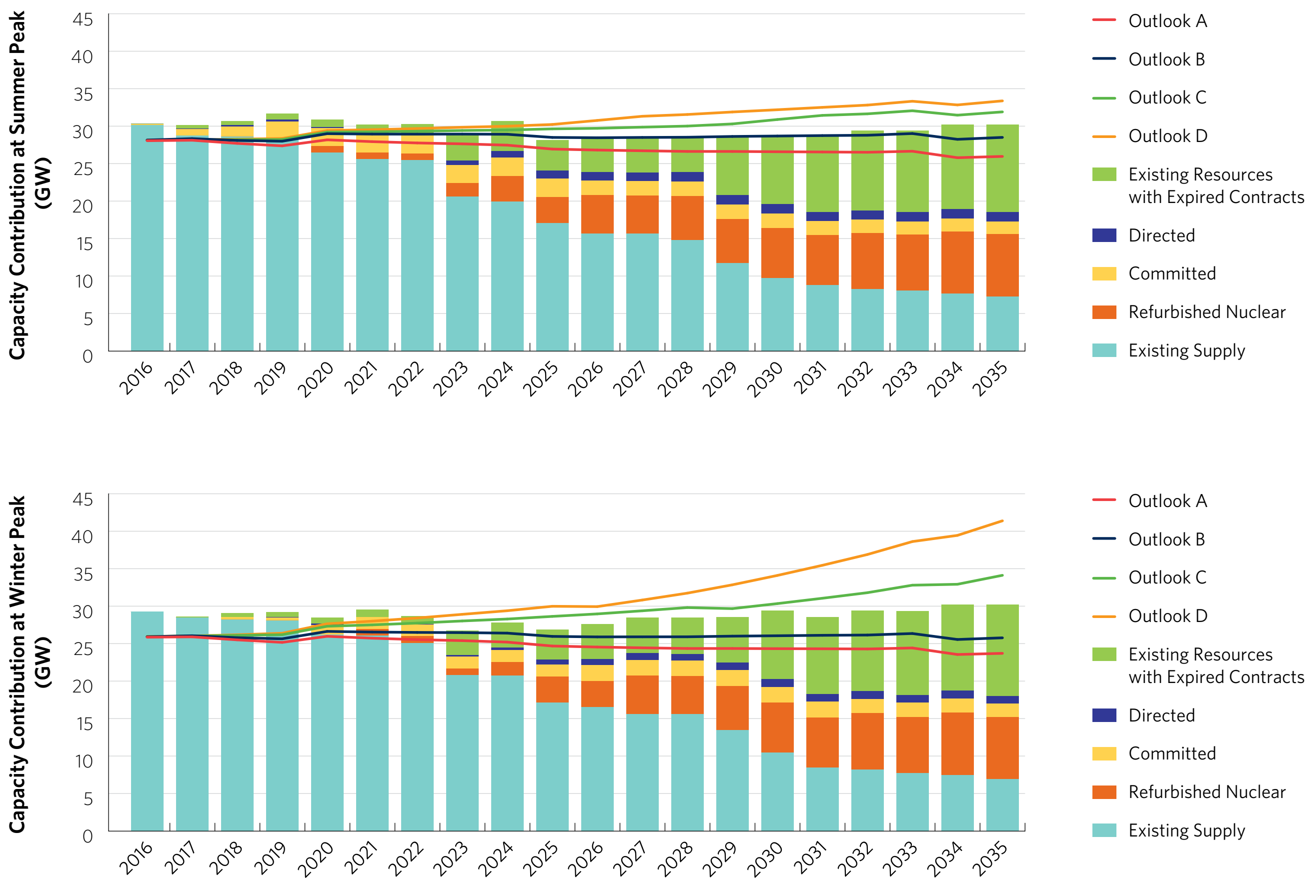
Provided that the planned resources come into service and existing resources continue to operate, Ontario's existing, committed and directed resources would be sufficient to meet the flat demand outlook. There would also be enough flexibility to address a lower growth in demand or to adapt to new opportunities or priorities. Additional resources would be required to meet any increased growth in demand such as in demand outlooks C and D (Figure 13).

3.3.1. Supply Outlook under Low Demand (Outlook A)

Ontario could adapt to lower demand outlooks by not re-contracting with generation facilities when contracts expire. Ontario also has the option of exercising nuclear refurbishment off-ramps in response to sustained low demand resulting from structural or disruptive technological change. These provide the ability to align future investments with the province's evolving needs, opportunities and priorities.

"Provided that the planned resources come into service and existing resources continue to operate, Ontario's existing, committed and directed resources would be sufficient to meet the flat demand outlook. There would also be enough flexibility to address a lower growth in demand or to adapt to new opportunities or priorities."

Figure 13: Available Supply at the Time of Peak Demand Relative to Total Resource Requirements[9]



For example, contracts for approximately 18 GW of existing supply will reach the end of their terms by 2035. About half of this supply, made up of natural gas-fired resources, will reach contract expiry in the mid-to-late 2020s. The other half of this supply is made up of renewable resources (Figure 14).

Ontario also has the option of exercising nuclear refurbishment off-ramps in certain circumstances. In the case of the refurbishment of units at the Bruce Nuclear Generating Station, these circumstances are spelled out in the contract between Bruce Power and the IESO. They include where changes in supply or demand for electricity have resulted in there no longer being a need to refurbish the remaining units or where there are more economic electricity supply alternatives.

These give Ontario the ability to align future investments with the province's evolving needs, opportunities and priorities. They also give it additional opportunities to diversify its commitments for supply resources, including through the use of mechanisms such as capacity auctions. Most of Ontario's contracts for natural gas-fired and renewable supply have been committed for terms of 20 years but, with some reinvestment, have a design life extending well beyond the term of their contracts. New mechanisms for acquiring capacity would provide a balance of short-term, medium-term and longer-term commitments, giving Ontario additional flexibility to adapt to changing circumstances and harness evolving opportunities as described in Section 3.3.4.

[9] The total resource requirement is the amount of supply needed to meet peak demand plus reserve requirements (to account for generator outages and variability in demand due to weather).

Figure 14: Installed Capacity of Future Contract Expirations

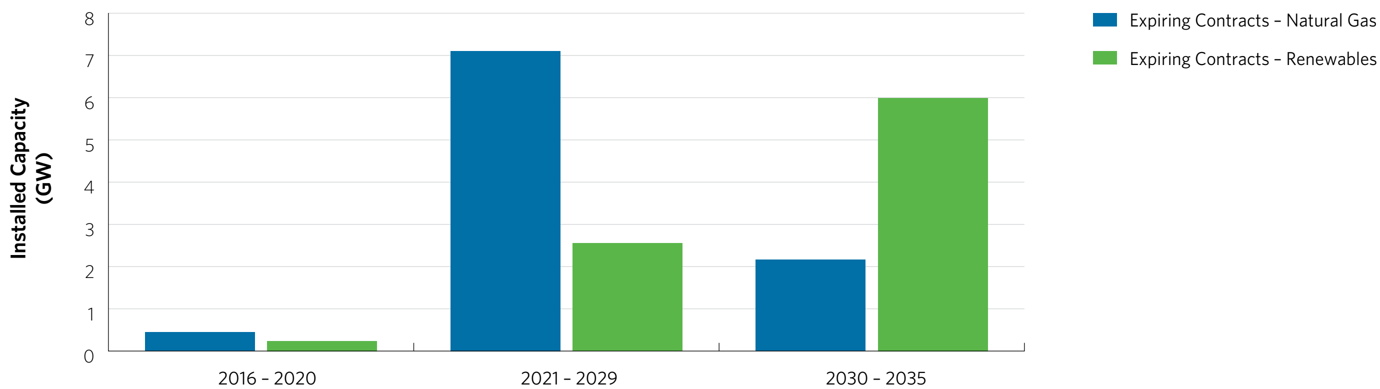
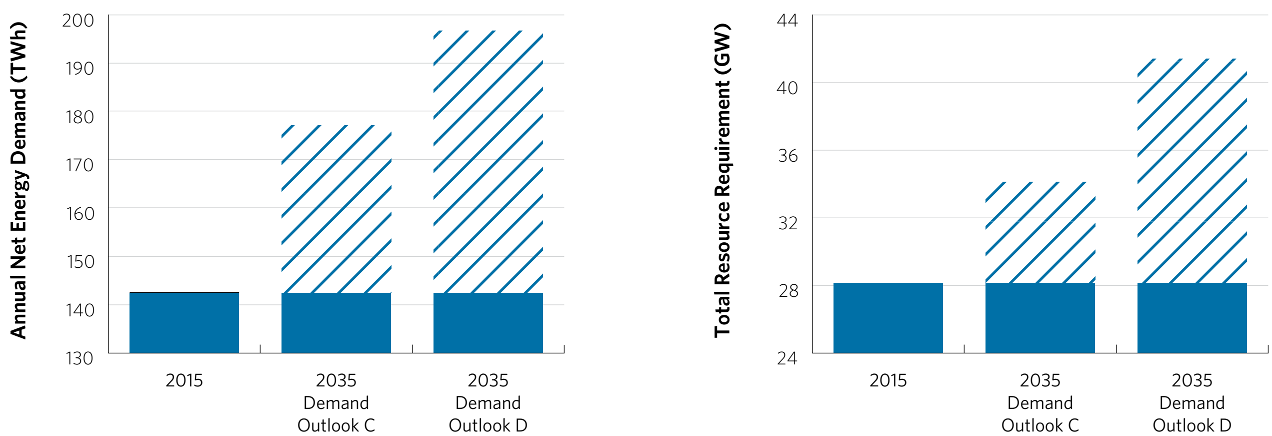


Figure 15: Electricity Supply Requirements in Outlooks C and D



3.3.2. Supply Outlook under Flat Demand (Outlook B)

As with lower demand, Ontario has a number of options for meeting flat demand or for meeting growth in electricity demand that remains at or near today's levels. The options include using Ontario's existing, committed and directed resources, provided that planned resources come into service and arrangements can be made for the continued operation of resources following contract expiry.

Ontario could also meet flat demand by taking advantage of improvements in technology performance and costs that may emerge to replace existing resources as contracts expire. Such new resources could include conservation, demand response, renewable and storage technologies, distributed energy resources and clean energy imports. As in the case for addressing reductions in electricity demand, Ontario's expiring resource contracts and off-ramps for nuclear refurbishment enable the province to take advantage of a wide range of future opportunities.

3.3.3. Supply Outlook under Higher Demand (Outlook C & D)

Ontario would require more electricity resources than it has today to serve higher levels of electricity demand growth. For perspective, energy demand under Outlook C and D by 2035 would be approximately 30 TWh and 50 TWh, respectively, higher than today. These quantities are roughly equivalent to between 20 percent and 40 percent of Ontario's current annual electricity demand. The total resource requirement in Outlook C and D increases to 34 GW and 41 GW, respectively, relative to approximately 28 GW today (Figure 15).

As illustrated in Figure 13, the IESO projects that Ontario will have sufficient resources to meet demand requirements generally over the next decade across all outlooks. Beyond the next decade, while there is increased uncertainty about the need for new resources, available technologies are likely to expand.

Table 2: Current Technology Characteristics

	Capacity	Energy	Operating Reserve	Load Following	Frequency Regulation	Capacity Factor	Contribution to Winter Peak	Contribution to Summer Peak	LUEC ($/MWh)
Conservation	Yes	Yes	No	No	No	Depends on Measure	Depends on Measure	Depends on Measure	$30-50
Demand Response	Yes	No	Yes	Yes	Limited	N/A	60%	85%	N/A
Solar PV	Limited	Yes	No	Limited	No	15%	5%	30%	$140-290
Wind	Limited	Yes	No	Limited	No	30%	30%	10%	$65-210
Bioenergy	Yes	Yes	Yes	Limited	No	40-80%	90%	90%	$160-260
Storage	Yes	No	Yes	Yes	Yes	Depends on technology/ application	Depends on technology/ application	Depends on technology/ application	Depends on technology/ application
Waterpower	Yes	Yes	Yes	Yes	Yes	30-70%	75%	71%	$120-240
Nuclear	Yes	Yes	No	Limited	No	85-95%	90-95%	95-99%	$120-290
Natural Gas	Yes	Yes	Yes	Yes	Yes	up to 65%	95%	89%	$80-310

Source: IESO. LUEC: Levelized Unit Energy Cost.

While higher demand could create a need for additional resources in the longer term, these needs are not projected to occur until the mid-2020s, with significant increases in resource requirements beyond 2030. Higher demands also provide greater potential for conservation. The value of conservation is greater in the higher demand outlooks as conservation can avoid the construction of new electricity infrastructure in these outlooks. This increased value of conservation could unlock conservation potential from existing end-uses that were otherwise uneconomic, supporting higher investment in more efficient technologies than under low demand outlooks.

3.3.4. Supply Resources

Ontario faces sizeable and increasing opportunities for further deployment of cleaner technologies including distributed energy resources to meet higher demand outlooks. These opportunities are being driven by technological advancements, evolutions in policy and market design and increasing customer engagement.

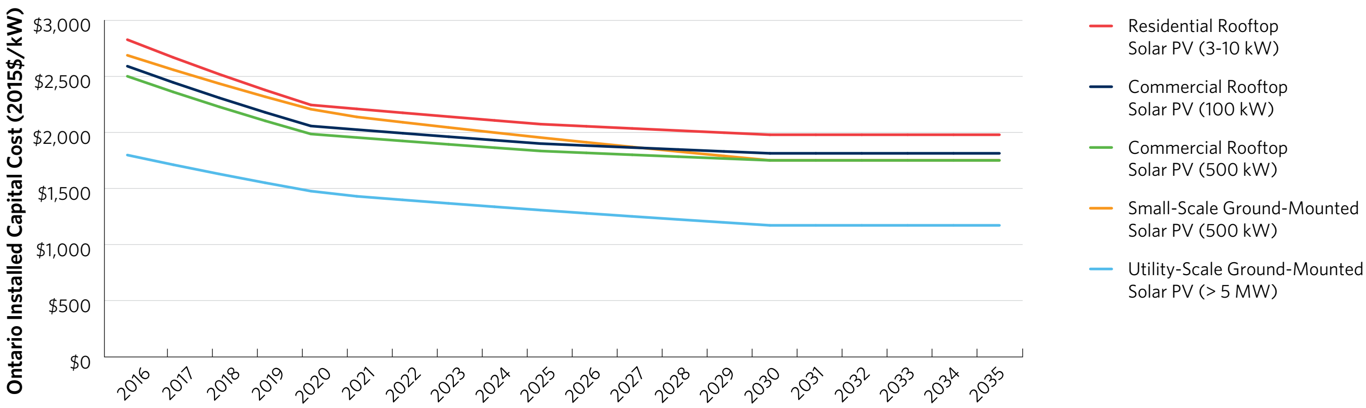
It is important to note that no single resource option can meet all customer needs at all times (Table 2). Some resources are baseload in nature; others are peaking. Some resources have higher operating costs but are dispatchable, while others have low operating costs but are highly variable. Electricity needs can relate to one or several types of products or services such as energy, capacity, regulation and ramping. Maintaining a diverse resource mix, where the different resources are complementary to each other, is an effective way to provide the various services necessary to support reliable and efficient operations.

The characteristics of each of these current technologies are discussed above.

Conservation: Conservation represents savings from energy efficiency programs and building codes and equipment standards. Conservation as a resource is described more fully in Section 3.2. Levelized unit energy cost (LUEC) values in Table 2 reflect the current range of costs to procure conservation.

Demand Response: Opportunities also exist for demand response (DR) resources. The 2013 LTEP included a DR goal of 10 percent by 2025 (approximately 2.5 GW). DR resources amounted to approximately 1.8 GW in 2015. The extent to which additional DR resources become available will depend on the demand outlook and the types of loads that can contribute in the event that Ontario becomes a winter-peaking system.

Figure 16: Installed Solar PV Cost Projections in Ontario



Solar Photovoltaic (PV): Solar PV is an example of a technology that is evolving. Solar PV module prices have declined by 70-80 percent over the past decade in line with improvements in efficiency, manufacturing and growing economies of scale. Solar PV prices are expected to continue to decline in the future (Figure 16), and applications for the technology, such as building-integrated solar PV (where solar PV is integrated into the building envelope), are also expected to diversify.

Ongoing evolution in solar PV technology and prices will increase options for customer participation in the electricity system, including those available in conjunction with other technologies and systems such as electricity storage, demand management and smart energy networks.

There are limitations on the role that solar PV might play in meeting winter peak needs. Solar output tends to be less aligned with peak electricity demands in the winter, which usually occur during dark mornings and dark evenings; this invites further consideration of how technologies such as solar PV might be effectively coupled with other enabling elements such as storage.

Wind Power: Wind turbine technologies continue to evolve. Turbines are generally getting taller and rotor diameters are becoming larger, which has helped boost output and drive down per-unit costs. This has resulted in reduced project footprints (same output with fewer turbines). The average output of a wind turbine has tripled over the past 20 years, and the cost of installed wind capacity has followed a declining trend worldwide. Given the maturity of the technology, the rate of cost decline is expected to be slower than in the past.

Bioenergy: Bioenergy refers to the conversion of energy in organic matter to produce electricity. This could include directly combusting organic fuel (biomass) or allowing the organic matter to decompose to produce methane gas (biogas or landfill gas), which in turn is combusted. Ontario has plentiful sources of bioenergy including residual materials from forestry operations that are left to decay on the forest floor, waste matter from agricultural production and animal livestock activities, by-products of food-processing operations, and municipal waste from landfills, compost and water treatment facilities. A number of bioenergy conversion technologies exist employing a variety of processes. Some technologies, such as landfill gas, are well-established while other technologies are still in the research phase. Challenges for bioenergy development include relatively high capital costs. Feedstock costs are generally zero since they are produced as a waste by-product although there may be a cost associated with transporting the fuel. Projects can benefit from being located close to where the feedstock is produced (such as at a farm or mill). This makes them suitable in rural and remote applications.

Electricity Storage: While some electricity storage technologies, such as pumped hydro storage, have been in operation around the world for over a century, a variety of newer technologies such as flywheels, batteries and compressed air facilities are gaining adoption. These technologies vary considerably in terms of their size and scale, how energy is stored, how long energy can be stored and their response time. At the same time, the costs of these technologies have been declining and are expected to further decline, they tend to be less geographically constrained as far as siting is concerned, and they involve shorter development lead times. Storage can also provide a number of services, for example, to help manage variable generation, provide bulk system services such as regulation or voltage control, or help manage outages.

Waterpower: Assessments over the years have identified significant remaining waterpower potential in the province. However, most of the potential exists in relatively remote regions of northern Ontario that lack transmission access. The cost of developing this potential is expected to be higher than in the past and projects require relatively longer lead times to develop. However, waterpower could be a significant source of non-carbon emitting energy and would provide opportunities to partner with First Nation and Métis communities. While Ontario's greatest remaining waterpower potential is in the north, there are also opportunities in the south, including redevelopments at existing water control structures (dams).

Nuclear: Nuclear power plants are baseload resources and carbon-free in operation. They produce electricity on a continuous basis with limited but increasing capability to vary output as demand varies (i.e., load follow). Opportunities for baseload resources, including nuclear, will be limited by the extent to which there is growth in baseload demand.

Construction cost of new nuclear plants has generally been increasing, and cost is an area of considerable uncertainty.

The refurbishments of Darlington and Bruce units are proceeding, consistent with the principles outlined in the 2013 LTEP.

Figure 17: Existing Interconnections

Additional information on Ontario's existing interconnections can be found in the Ontario Transmission System section of the IESO's 18-Month Outlook
http://www.ieso.ca/Documents/marketReports/OntTxSystem_2016jun.pdf

Gas-fired Resources: Gas-fired resources produce lower GHG emissions than coal-fired resources and can complement a low-carbon supply mix. The gas fleet provides significant flexibility to respond to the intermittency associated with renewable generation.

Many of the current technologies outlined here could also support firm electricity imports or be deployed as distributed energy resources.

Firm Electricity Imports: In addition to opportunities within the province, opportunities also exist for greater electricity trade between Ontario and its neighbours. Ontario currently has interconnections with five of its neighbours: Quebec, Manitoba, Minnesota, Michigan and New York. These interconnections facilitate the import and export of electricity (Figure 17). Electricity trade now provides operational and planning flexibility and enhances the reliability and cost-effectiveness of the Ontario electricity system. Interties can also be used to obtain firm capacity to support resource adequacy as well as energy to meet consumption where they can be pursued at costs below domestic resources (factoring in transmission). As an example, Ontario recently entered into a seasonal capacity swap agreement with Quebec for the next decade. Under the terms of the deal, Ontario provides firm capacity to Quebec in the winter (when Ontario has its greatest surplus) and Quebec provides firm capacity in the summer (when Quebec has its greatest surplus). The introduction of competition for capacity from resources located outside of Ontario offers further opportunity to lower costs and support reliability. Taking advantage of available supply through existing interconnections could have the effect of reducing Ontario-based resource requirements. The scale and economics of any potential firm import capacity deal will depend greatly on the need for additional transmission infrastructure on both sides of the border.

Distributed Energy Resources (DERs): Evolutions in technology and policy are also expanding opportunities for customer engagement and participation in the Ontario electricity system and are driving a transition towards a system more characterized by two-way flows and a growing prevalence of distributed energy resources. The utility-customer relationship is becoming more complex against this backdrop as an increasing number of products and services are becoming available to customers. Some of these products and services compete directly with utility services. For example, a wide range of home energy technologies and smart home appliances are now available, and the competition to become the provider of the home “internet-of-things” ecosystem is growing. A number of communities are now developing community energy plans, and distributed energy resources have become a key component of those plans. Distributed energy resources are also being promoted by some communities in the context of ongoing regional planning activities across the province.

The higher demand outlooks provide greater opportunities for harnessing DERs without stranding assets as the risk of underutilizing assets becomes less of an issue. DERs can be part of the solution in addressing higher demands and reducing the need for new grid-connected resources. DERs can also enhance supply security and resiliency. This potential is illustrated by the experience of New York City during Hurricane Sandy. The storm left eight million people without power in New York, and some of the hardest hit areas were left without power for two weeks. In the heart of New York City, however, NYU’s Washington Square campus remained powered by a 13.4 MW natural gas-fired combined heat and power (CHP) system that had recently been installed. In Ontario, several customers (for example, Metrolinx) have installed small CHP systems in their facilities that are capable of providing heat and power during an interruption of grid power. At the same time, distributed energy resources and other local solutions are receiving greater attention with greater involvement of customers and communities in regional planning. Addressing barriers to the adoption of distributed energy resources, such as cost allocation and integration issues, could help to better realize their potential benefits.

Pilot programs and lessons learned from other jurisdictions can help Ontario to better understand available or emerging options and identify barriers that might hinder their broader realization.

While there are many potential benefits in evolving to an electricity system that relies more on distributed energy resources, care must be taken in managing this evolution to ensure that it does not result in higher ratepayer costs, stranding of existing assets or increased GHG emissions.

3.4. Market and System Operations Outlook

Over the planning period, a number of foreseeable changes are expected to result in a power system that is increasingly variable and complex to operate on a day-to-day basis. Changes such as increases in variable renewable generation and distributed energy resources, nuclear decommissioning and refurbishments, and changing customer demand patterns will change the flow patterns on the bulk system. New facilities, tools and/or measures will need to be in place to help maintain system reliability and operability through this significant transition period.

> "Over the planning period, a number of foreseeable changes are expected to result in a power system that is increasingly variable and complex to operate on a day-to-day basis."

The IESO has successfully integrated over 6,000 MW of wind and solar PV into Ontario's electricity system. The IESO has made strides in integrating significant amounts of variable generation while maintaining reliable operations of the power system. This has been achieved through efforts such as the Renewable Integration Initiative (RII), which brought in centralized forecasting of variable generation and the capability to dispatch variable generators.

While the IESO is working on methods for improving short-term forecasting, measures are also being taken to maintain reliable and efficient operations in the face of an evolving power system. These measures include additional frequency regulation, flexibility, control devices, and system automation. Greater coordination between the grid operator and embedded resources, directly or through integrated operations with LDCs, could also improve visibility into the distribution system and reduce short-term forecast errors.

Load-following capability is primarily provided by peaking waterpower resources, the Sir Adam Beck Pump Generating Station and natural gas-fired generation, and is sufficient in the near term. However, the need for flexibility will increase over time. In addition to existing mechanisms for acquiring ancillary services, consideration is being given to expanded markets that would allow for more dynamic real-time coordination.

Going forward, regulation and flexibility requirements will be assessed on an ongoing basis, along with the resource fleet available to provide these services. Electricity markets will play a stronger role in ensuring adequate supply of flexible resources through signals that price and dispatch these services. It is anticipated that many resource types will be able to compete to provide regulation and/or flexibility, including resources such as energy storage and aggregated loads. Some of these newer technologies can provide operability characteristics that are not achievable from some traditional resources, such as very fast ramp rates, which may allow efficiency improvements in how these services are currently dispatched.

3.5. Transmission and Distribution Outlook

Current transmission projects already at various stages of planning and implementation are outlined in Table 3.

No significant new transmission investments would be required in an outlook of flat electricity demand served by existing and currently planned resources. However, additional transmission or local resources to address specific regional needs may be identified in the future as regional planning continues across the province.

The need to replace aging transmission assets over coming years will also present opportunities to right-size investments in line with evolving circumstances. This could involve up-sizing equipment where needs exist such as in higher demand outlooks; downsizing, to reduce the risk of underutilizing or stranding assets; or even removing equipment that is no longer required, such as in the low demand outlook or in parts of the province that have seen reduced demand. Such instances may also present opportunities to enhance or reconfigure assets to improve system resilience and allow for the integration of variable and distributed energy resources.

In higher demand outlooks, investments in transmission will be required to accommodate new resources. Transmission to integrate those resources would have significant lead time requirements of up to 10 years. Much of Ontario's undeveloped renewable resource potential is located in areas with limited transmission capacity – new investments in Ontario's transmission system would be required to enable further resource developments in the province or significant imports into the province. For example, incorporation of renewable resources located in northern Ontario would require reinforcements to the major transmission pathway between northern and southern Ontario, the North-South Tie. A number of transmission upgrades within Northern Ontario would also be required to alleviate constraints within the region. To facilitate any potential large firm import capacity arrangement from Quebec/Newfoundland, major system reinforcements in eastern Ontario would be required – a new high-voltage direct current (HVDC) intertie to Lennox would be an example. The incorporation of new resources in Southwestern Ontario would require reinforcement of the transmission system, such as in the West of London area, as well as additional enabling facilities. Similarly, investments in new resources in the Greater Toronto Area might also trigger the need to reinforce the bulk transmission system.

In the near term, the system can manage increases in electricity demand driven by electrification. However, LDCs and transmitters may be more significantly impacted as local peak demands grow.

Table 3: Status and Drivers of Transmission Projects in Outlook B[10]

		Drivers			
Projects	Status	Maintaining Bulk System Reliability	Addressing Regional Reliability and Adequacy Needs	Achieving 2013 LTEP Policy Objectives	Facilitating Interconnections with Neighbouring Jurisdictions
East-West Tie Expansion	Expected to be in service in 2020.	●		●	
Line to Pickle Lake	Plan is complete; expected to be in service in early 2020.		●	●	
Remote Community Connection Plan	Draft technical report released; development work underway for connection of 16 communities; engagement with communities is ongoing.		●	●	
Northwest Bulk Transmission Line	Hydro One is carrying out early development work to maintain the viability of the option.	●		●	
Supply to Essex County Transmission Reinforcement	Expected in-service date of 2018.		●		
West GTA Bulk reinforcement	Plan is being finalized.	●			
Guelph Area Transmission Refurbishment	Expected to be in service in 2016.		●		
Remedial Action Scheme (RAS) in Bruce and Northwest	Under development. Northwest RAS targeted for late 2016 in-service; Bruce RAS early 2017.	●			
Clarington 500/230kV transformers	Expected to be in service in 2018.	●			
Ottawa Area Transmission Reinforcement	Project has been initiated; expected to be in service 2020.		●		●
Richview to Manby Transmission Reinforcement	Expected to be in service in 2020.		●		

[10] A merchant 1 GW bi-directional, high-voltage, direct current Lake Erie underwater transmission link is currently being proposed by ITC Holdings Corp. It would directly connect the Ontario transmission system at the Nanticoke Transformer Station with the PJM market in Pennsylvania. The proposed in-service date of the project is 2019. This is a merchant project that was not identified by the IESO as being needed to meet system requirements.

The extent to which the transmission and distribution system will be impacted will depend on the location of electrification driven demand growth. The low voltage distribution system is expected to be impacted to a much greater degree. For example, some distribution infrastructure is designed for a five kilowatt (kW) peak household load. On a cold day, one household equipped with an air-source heat pump could consume as much as 15 kW. Though the system as a whole could supply this need, transmission and distribution infrastructure in some regions would be challenged by rapid and widespread conversions from gas to electric heating. This could be compounded by the effect of home charging of EVs, whose impact on peak demand can also vary substantially with charging patterns. Some LDCs have already undertaken analysis of their systems to determine the potential impact that high saturation of EVs will have on their system and what measures could be taken to manage emerging needs in the most cost-effective manner. These measures include a focus on customer-based solutions such as the use of load control devices, DER and storage integrated with the local and provincial utility control systems. While the impact of electrification in space heating, water heating and transportation will increase electricity requirements across the province, the impact would be the most prominent in urban centres, with implications for regional transmission systems that will need to be considered as part of the regional planning processes.

The increased penetration of DERs will have implications for distribution and transmission systems. A number of facilities, tools and measures will be needed to ensure that the power system can continue to be reliably operated amid increasing amounts of DERs. In some cases, DER technologies themselves can help address some of these requirements. Pilot projects are building experience and capability with DERs within the sector. Strategies and options for using DERs to address local issues could be laid out in regional planning processes, working together with transmitters and LDCs.

"In the near term, the system can manage increases in electricity demand driven by electrification. However, LDCs and transmitters may be more significantly impacted as local peak demands grow... The low voltage distribution system is expected to be impacted to a much greater degree."

3.6. Emissions Outlook

With the phase-out of coal-fired generation, the carbon emissions from Ontario's electricity fleet now come primarily from natural gas-fired generation.

Emissions are expected to continue to decline over the next five years as additional renewable generation enters service. Beyond this period, emissions will depend on the level of electricity demand and the extent to which energy production from the existing natural gas-fired fleet is displaced.

In the flat demand outlook, emissions would rise slightly following the retirement of the Pickering Nuclear Generating Station but would remain well below historical levels and stay relatively flat through to 2035 (Figure 18).

When Ontario's cap-and-trade system takes effect in 2017, the electricity sector will see the cost of carbon reflected in the wholesale electricity price when natural gas-fired resources are on the margin. The Ontario market price for carbon will also be applied to electricity imports. This will provide a level playing field for Ontario generators in the IESO market and reduce imports from higher-emitting sources. At the same time, imports to Ontario from non-emitting jurisdictions such as Quebec could increase, other things being equal.

On the other hand, the addition of a carbon price to emitting Ontario generators would reduce the amount of electricity exported from natural gas-fired generators and so reduce Ontario GHG emissions, with the impact depending on whether the receiving jurisdictions adopt similar carbon pricing as Ontario and Quebec.

Under the higher demand outlooks, the effects on carbon emissions will depend on the extent to which the existing natural gas-fired fleet is used to meet increases in demand. The existing natural gas-fired combined-cycle fleet has considerable capability to ramp up energy production should it be required. However, increased utilization of the existing combined-cycle fleet would increase emissions. Therefore, in this report, consideration of how to address the higher demand outlooks was based on keeping GHG emissions in the electricity sector low or declining.

Figure 18: Electricity Sector GHG Emissions in Outlook B

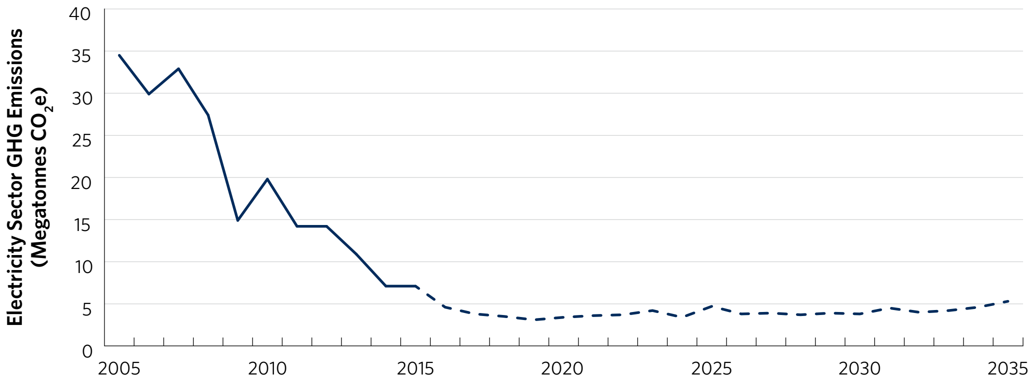


Figure 19: Total Cost of Electricity Service in Outlook B

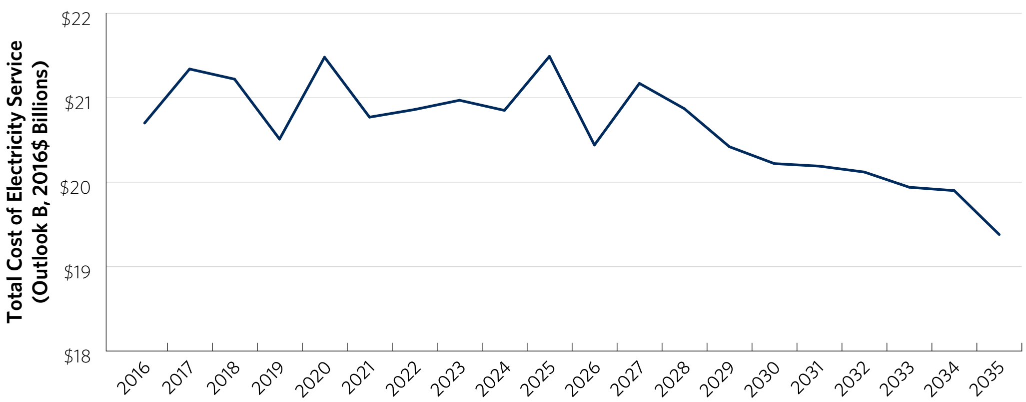


Figure 20: Average Unit Cost of Electricity Service in Outlook B

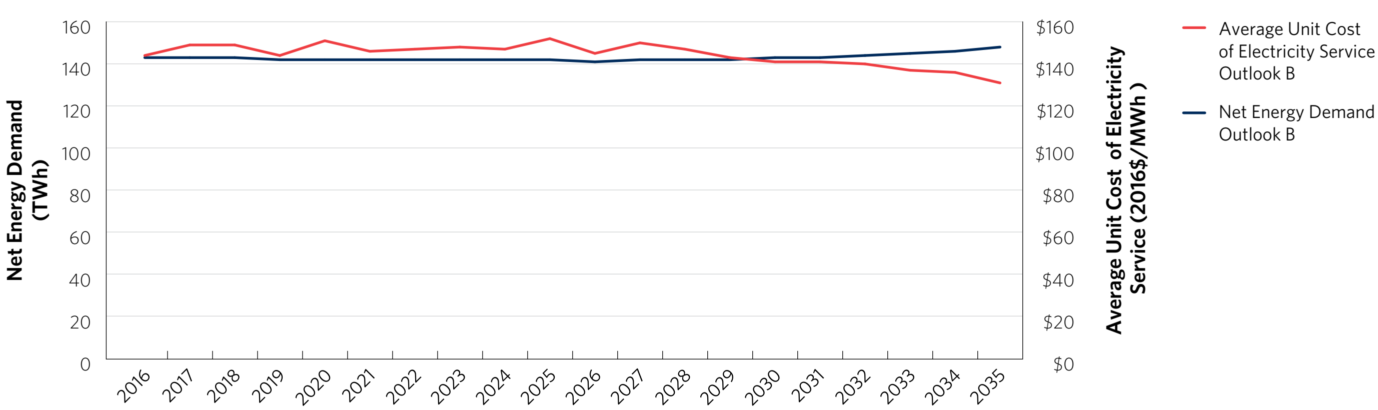
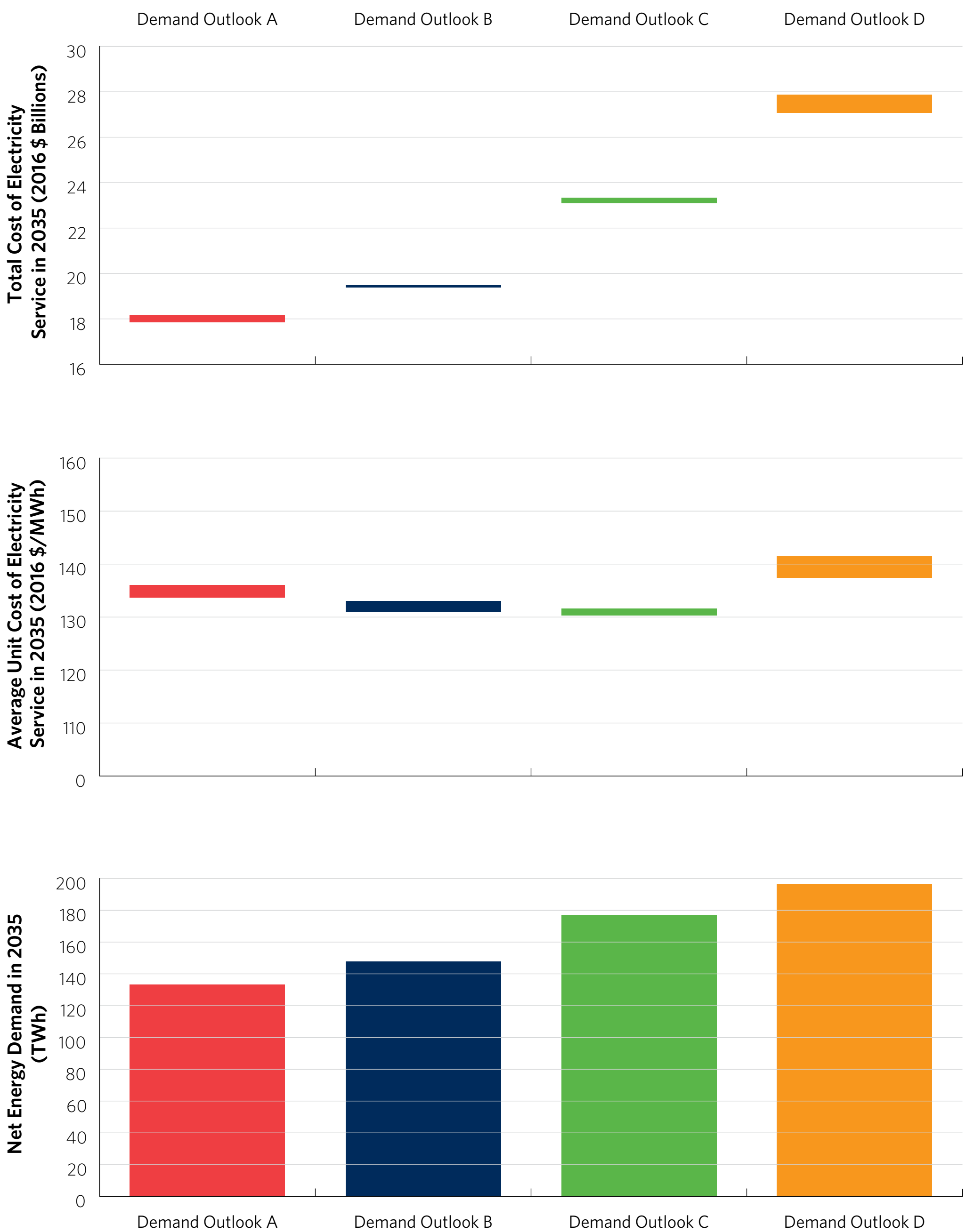


Figure 21: Cost of Electricity Service across Demand Outlooks



3.7. Electricity System Cost Outlook

The total cost of electricity service over the planning outlook will be a function of demand growth, the cost of operating the existing system and the investments required in new resources to meet potential needs.

In the flat demand outlook, the total cost of electricity service would average approximately $21 billion per year (2016$) over the next 10 years and is estimated to decrease to approximately $19 billion per year by 2035 (Figure 19). Cost reductions are premised on expectations of lower revenue requirements among generators whose existing contracts have expired but continue to operate at costs below existing contract rates.

The average unit cost of electricity service decreases by an average annual 0.3 percent per year (2016$) over the 20-year period. Ongoing investments lead to increases in the first 10 years of the outlook at an average annual rate of 0.4 percent per year (Figure 20). Unit rates decrease over the last 10 years of the outlook due to reduced investments in electricity resources.

In higher demand outlooks, additional investments in new resources (conservation, generation and transmission) would be required to meet the increase in demand (peak and energy requirements) and to keep emissions within the range of the flat demand outlook. The annual cost of electricity service would rise by approximately $4 billion to $10 billion by 2035 (2016$) (Figure 21). However, this would be associated with an increase in energy consumption in the province. As a result, the average unit cost of electricity service would be within the range of the flat demand outlook.

> "The existing natural gas-fired combined-cycle fleet has considerable capability to ramp up energy production should it be required. However, increased utilization of the existing combined-cycle fleet would increase emissions."

Conclusion

4

Actions taken over the past 10 years have left Ontario well positioned to meet future provincial needs. However, Ontario's electricity sector will face significant change over the next 20 years as it moves forward to achieve conservation and demand response targets, manages nuclear refurbishment, brings into service the remaining committed and directed supply resources, while addressing the impact of the rapid pace of technological evolution and the effect on demand of government climate change policies.

Looking ahead, the IESO has considered a range of potential long-term electricity demands and options for addressing them. Evolutions in policy, technology and markets along with rising customer engagement are happening across the sector, including in the areas of low-carbon technologies and distributed energy resources. Expiring electricity resource contracts, nuclear refurbishment off-ramps and transmission assets reaching replacement age provide Ontario with flexibility to take advantage of options as they arise. Positioning Ontario to take advantage of future opportunities and mitigate future risks will require ongoing efforts. Considerations in this regard include:

- Maintaining situational awareness: Developments in technology and policy need to be monitored as well as information about drivers of risk for the sector, such as resource availability uncertainty and demand uncertainty. Situational awareness would be assisted by ongoing and proactive engagement with sector participants, communities, customers and stakeholders.
- Assessing opportunities and risks in an integrated way: It is important to consider individual opportunities within the context of broader systems and to consider both benefits and risks. Assessing options in an integrated way can deepen our understanding of potential synergies, barriers and implementation requirements.
- Resolving barriers: Barriers may exist to the deployment or procurement of new technologies or approaches. Regulatory frameworks and procurement processes would need to continue to evolve to address changing circumstances and technologies.

In the IESO's higher demand outlook, electrification of end-uses in support of climate change actions could be met in a variety of ways. While Ontario would require additional electricity resources to meet the associated higher levels of demand growth, it has a variety of options available, including distributed energy resources and enhanced conservation. Higher demands could be served in ways that sustain recent reductions in electricity sector emissions while significantly reducing carbon emissions in the broader economy, including through the greater substitution of electricity for fossil fuels in residential and commercial space and water heating, light duty vehicles, public transit and in some industrial applications.

Electrification-driven demand growth possibilities underscore the challenge of scale and integration that could be brought by significantly higher needs. For instance, the magnitude of growth associated with Outlooks C and D would exceed the contribution that any single electricity resource option could provide on its own. Meeting this scale of electricity demand growth would require the coordinated deployment of multiple low-carbon options.

The development of low-carbon resources to address the higher demand outlooks would also require significant investments in Ontario's transmission system. Electrification and the growth of distributed energy resources would also drive the need for significant investments at the distribution level.

The scale, cost and practical challenges of implementing options to address greater electrification further highlights the importance of conservation as a method of moderating electricity demand growth. Capturing those conservation opportunities would be central to meeting high electrification options.

Transmission development activities should be considered when making supply decisions. This could include activities to incorporate resources in northern Ontario and to unlock resource potential in the eastern and southwestern regions of the province.

While significant new investments would be required to address the higher demands in Outlooks C and D, with the increase in energy consumption, the average unit cost of electricity service would remain within the range of the flat demand future.

In brief, Ontario has access to options for meeting electrification-driven demand growth in ways that result in significant economy-wide carbon emission reductions. In addressing the associated planning issues, the IESO is committed to supporting the Ministry's consultations as the new LTEP is developed.

The IESO engaged in discussions with key stakeholder and community groups and invited input into this planning outlook through the its Stakeholder Advisory Committee (SAC). Written comments were posted to the IESO SAC webpage along with material to illustrate the IESO's consideration of the input received.

The IESO wishes to thank the members of the SAC and the many stakeholder and community groups involved in these discussions.

5 Appendices and Modules

Appendices

Appendix A: June 10, 2016 Letter from the Minister of Energy to the IESO re: Technical Report

Appendix B: Data Tables for the OPO Technical Report

Modules

The following modules can be found on the IESO website: ieso.ca

Module 1: State of the Electricity System: 10-Year Review

Module 2: Demand Outlook

Module 3: Conservation Outlook

Module 4: Supply Outlook

Module 5: Market and System Operations & Transmission and Distribution Outlook

Module 6: Emissions Outlook

Module 7: Electricity System Cost Outlook



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Appendix A

Ministry of Energy

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Ontario

Friday June 10, 2016

Mr. Bruce Campbell
President and Chief Executive Officer
Independent Electricity System Operator
1600–Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. Campbell,

RE: IESO Technical Report

The Government of Ontario plans to issue a new Long-Term Energy Plan (LTEP) that will set out and balance Ontario's goals of cost-effectiveness; reliability; clean energy; community and indigenous engagement; and emphasis on conservation and demand management. As you know, Bill 135, the *Energy Statute Law Amendment Act, 2016*, has received Royal Assent. To support the development of the LTEP, we anticipate that the IESO will submit a technical report on the adequacy and reliability of Ontario's electricity resources, pursuant to section 25.29(3) of the *Electricity Act, 1998*, as that section will be amended (the "Act").

The technical report shall provide a ten-year review (2005-2015) and a twenty year forecast (2016-2035) of the electricity system with respect to:

- Costs of the electricity system
- Conservation
- Demand
- Supply resources including electricity storage
- Capacity
- Reliability
- Market and System Operations
- Transmission and Distribution
- Air emissions from the electricity sector

The forecasts shall consider existing supply commitments and directions, as well as other related government commitments, including, but not limited to, the recently released Climate Change Action Plan, the *Climate Change Mitigation and Low-Carbon Economy Act, 2016*, and the *Vancouver Declaration*.

…/cont'd

The technical report will provide an objective baseline and help facilitate the formal consultation process for the development of the LTEP. In accordance with the Act, the technical report will be posted on a publicly-accessible Government of Ontario website. Consistent with the Open Data Directive, datasets and key assumptions used to develop the technical report will also be made available to the public. I encourage you to work with my staff to ensure the technical report and underlying data meet Web Content Accessibility Guidelines.

The Act will require the technical report to be posted publicly prior to the Ministry undertaking any LTEP consultations. I therefore request that the report be submitted to the Ministry no later than September 1, 2016.

If you should have any questions about this request or require further clarity, please do not hesitate to contact me.

Sincerely,

Bob Chiarelli

Bob Chiarelli
Minister

c: Tim O’Neill, Chair, Independent Electricity System Operator
Serge Imbrogno, Deputy Minister, Ministry of Energy
Independent Electricity System Operator Board Members
Independent Electricity System Operator Stakeholder Advisory Committee

Data Tables for the OPO Technical Report

September 2016

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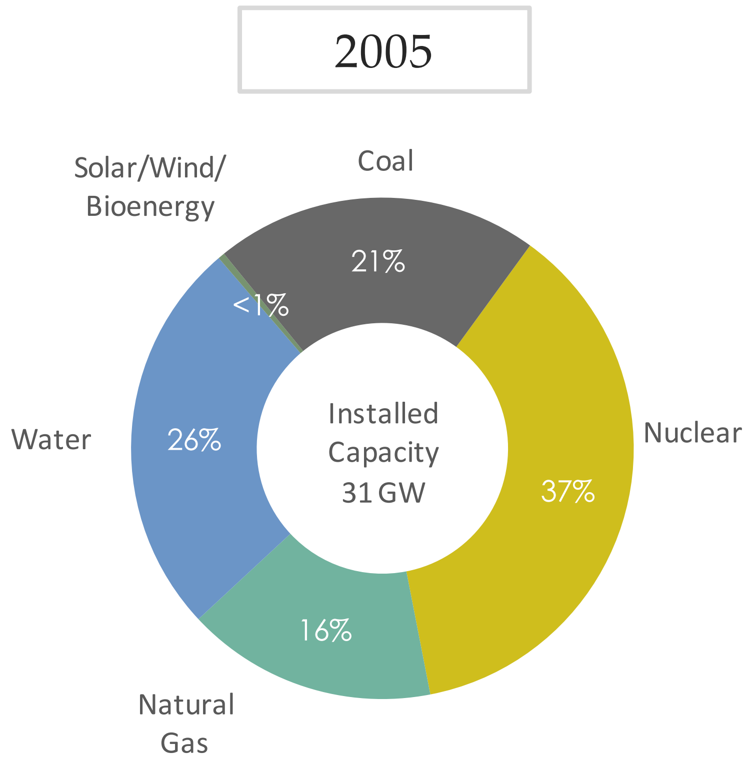
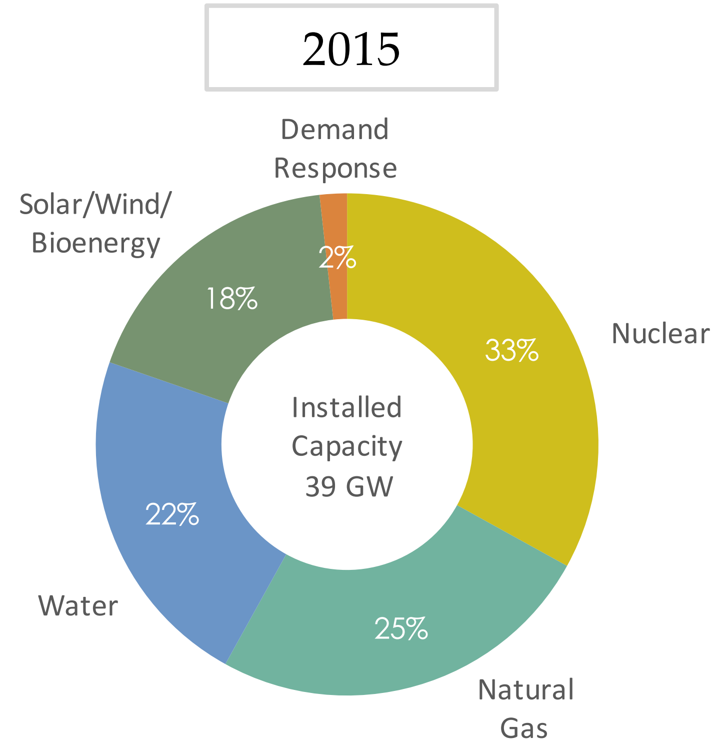
Figure 1: Ontario Installed Supply Mix in 2005 and 2015

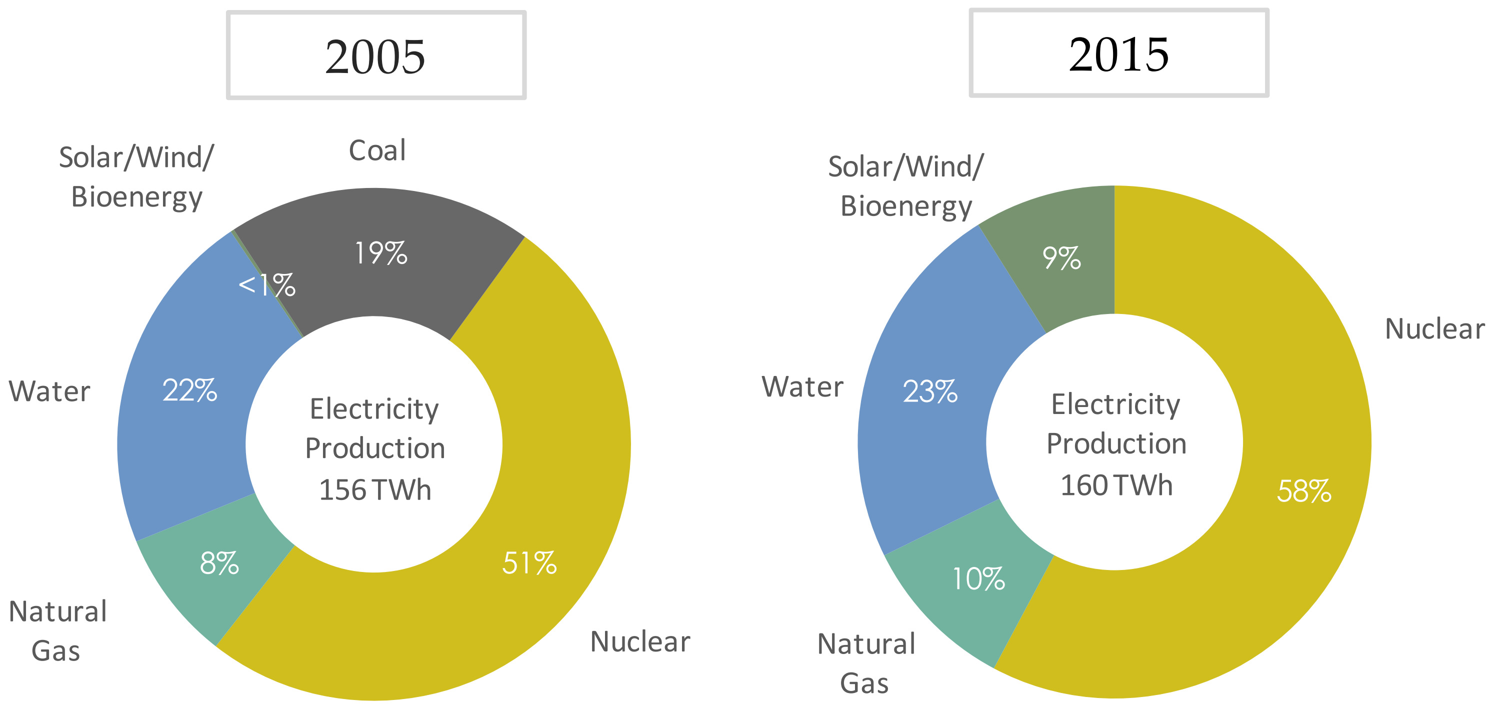




Data for Figure 1: Ontario Installed Supply Mix in 2005 and 2015

MW	2005	2015
Nuclear	11,397	13,014
Natural Gas & Oil	4,976	9,852
Water	7,910	8,768
Solar/Wind/Bioenergy	134	7,068
Coal	6,434	0
Demand Response	0	690

Figure 2: Ontario Electricity Production in 2005 and 2015



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Data for Figure 2: Ontario Electricity Production in 2005 and 2015

TWh	2005	2015
Nuclear	79.0	92.3
Natural Gas & Oil	12.9	15.9
Water	34.0	37.3
Solar/Wind/Bioenergy	0.3	14.2
Coal	30.0	0.0

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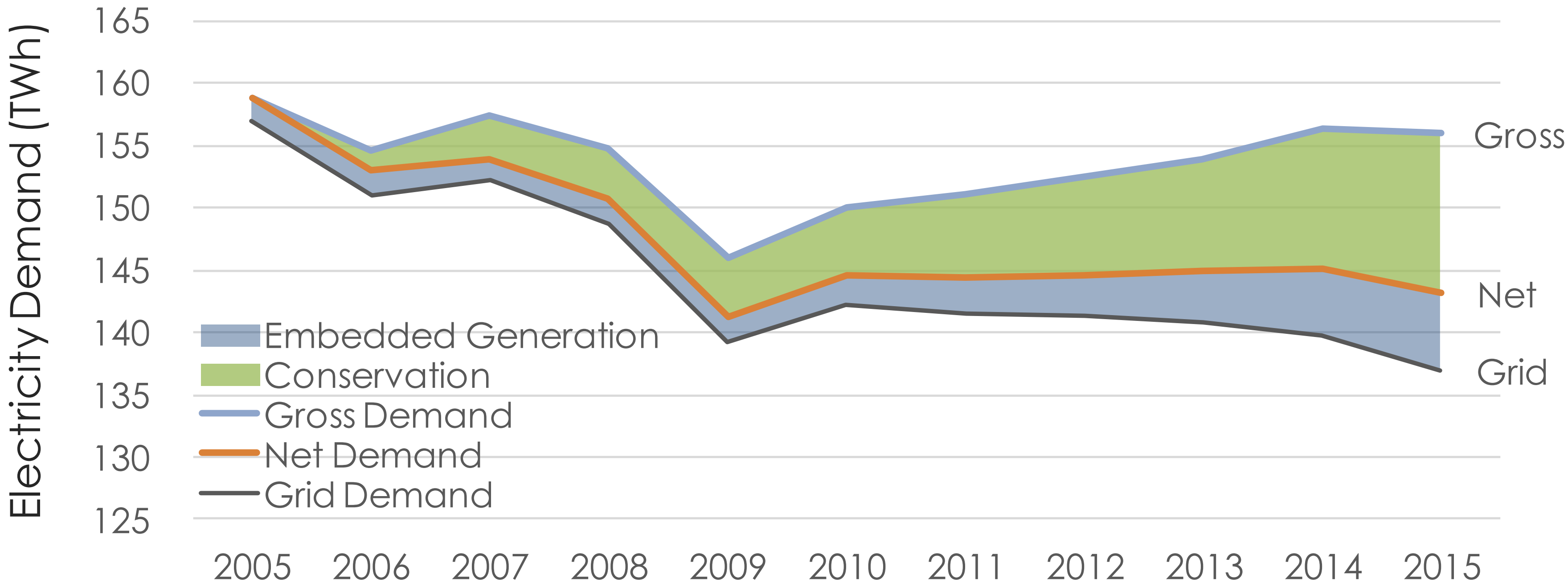
Figure 3: Historical Ontario Energy Demand



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

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Data for Figure 3: Historical Ontario Energy Demand

TWh	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Gross Demand	158.8	154.4	157.3	154.7	146.0	149.9	151.0	152.3	153.8	156.2	155.8
Conservation	0.0	1.6	3.5	4.0	4.9	5.4	6.7	7.9	8.9	11.3	12.8
Net Demand	158.8	152.8	153.8	150.6	141.1	144.5	144.3	144.5	144.8	144.9	143.0
Embedded Generation	1.8	1.7	1.6	2.0	2.0	2.3	2.8	3.2	4.1	5.1	6.0
Grid Demand	157.0	151.1	152.2	148.7	139.2	142.2	141.5	141.3	140.7	139.8	137.0

Figure 4: Conservation Savings in 2015

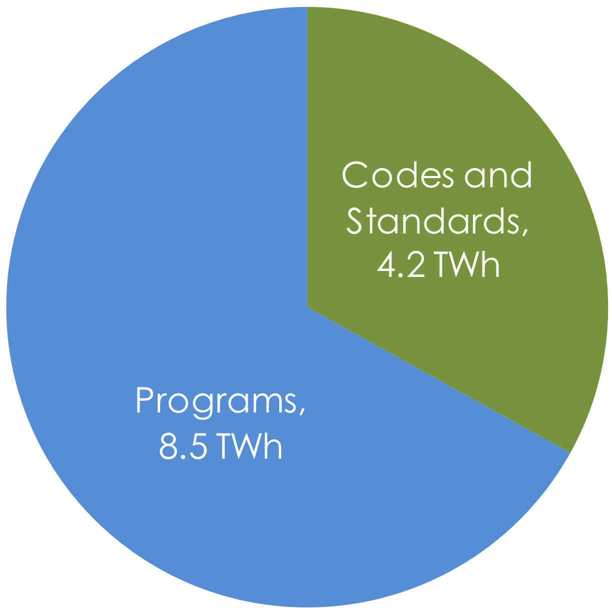

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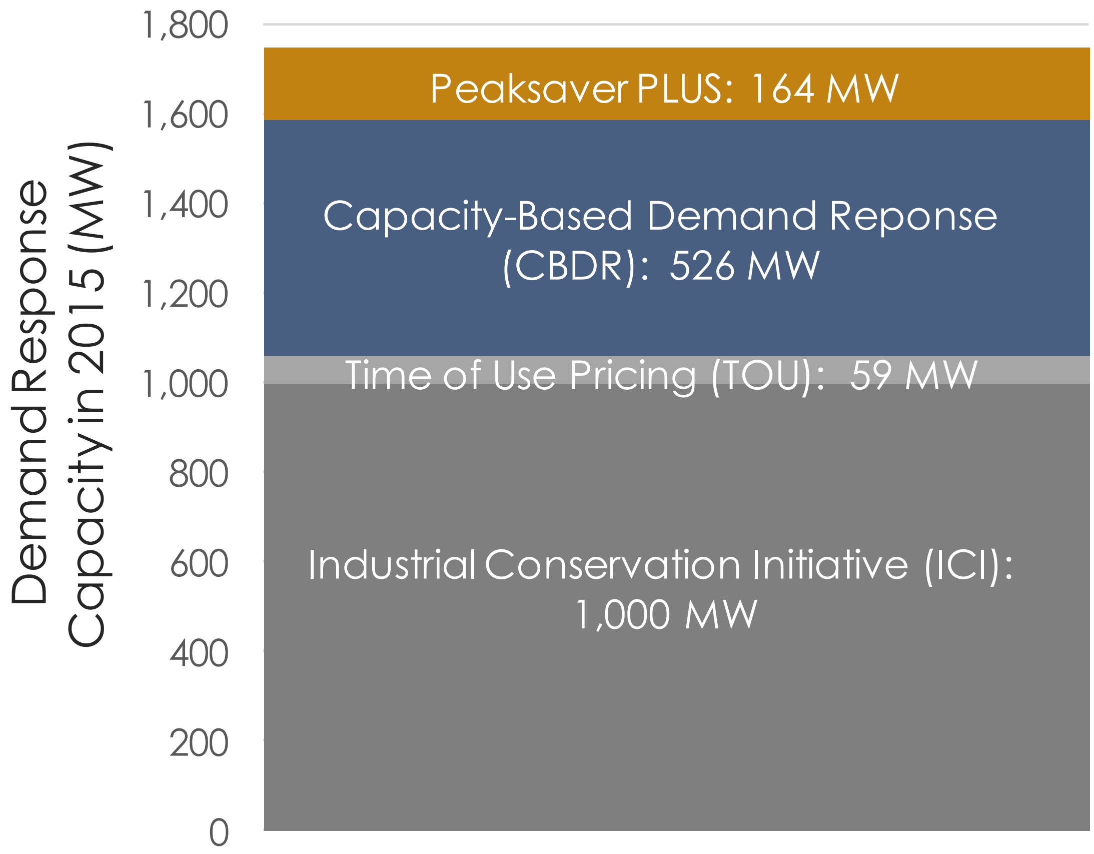
Figure 5: Demand Response Capacity in 2015



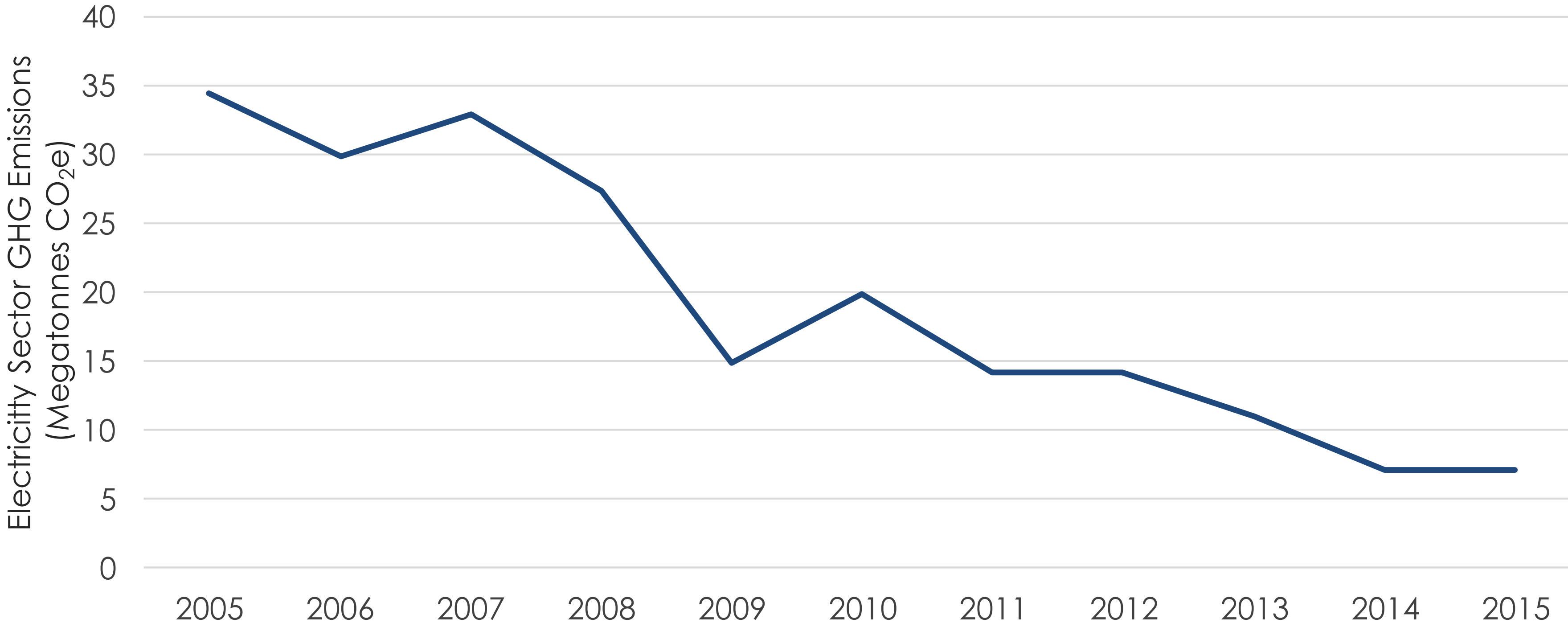
Peaksaver PLUS and CBDR can controlled by system operators. These programs are treated elsewhere as supply resources totalling 690 MW

TOU pricing and ICI reflect customer response to prices. These programs are considered as part of the net demand forecast

Data for Figure 5: Demand Response Capacity in 2015

Category	MW
TOU	59
ICI	1,000
Peaksaver PLUS	164
CBDR	526

Figure 6: Electricity Sector GHG Emissions



Note: GHG emissions for 2015 is an estimate

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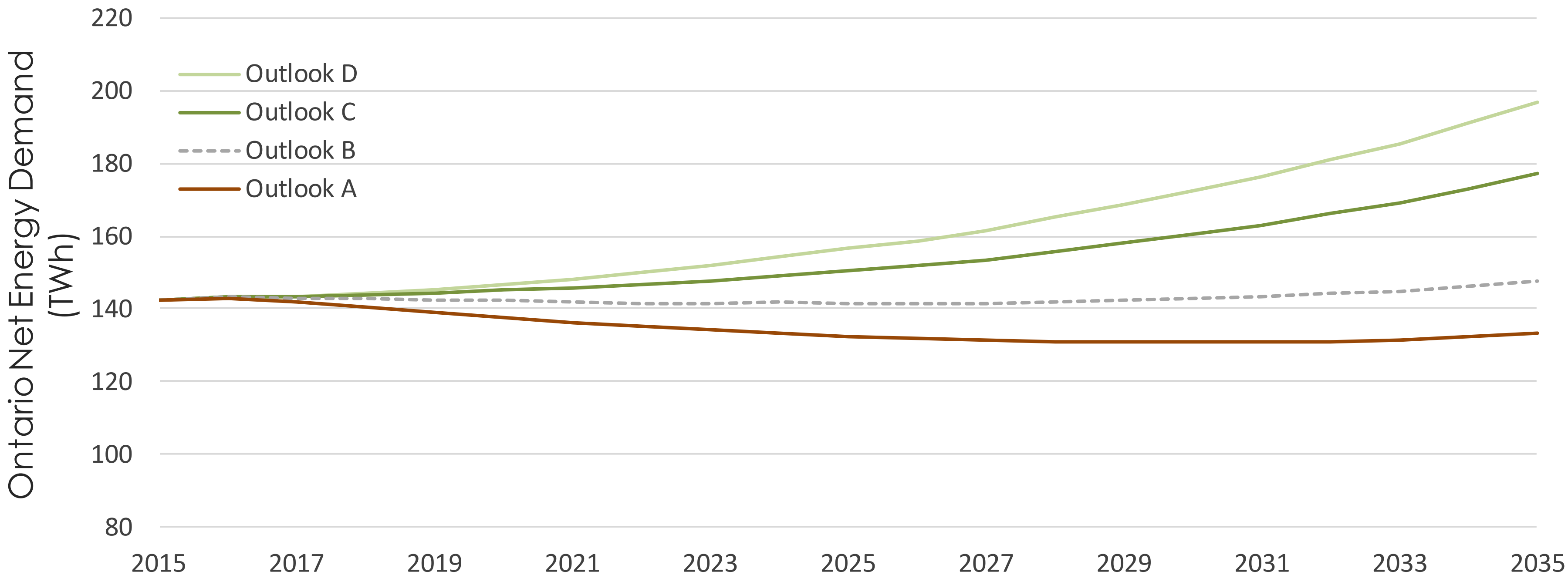
Data for Figure 6: Electricity Sector GHG Emissions

MT CO_2e	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Electricity Sector GHG Emissions	34.5	29.9	32.9	27.4	14.9	19.8	14.2	14.2	10.9	7.1	7.1

Figure 8: Ontario Net Energy Demand across Demand Outlooks

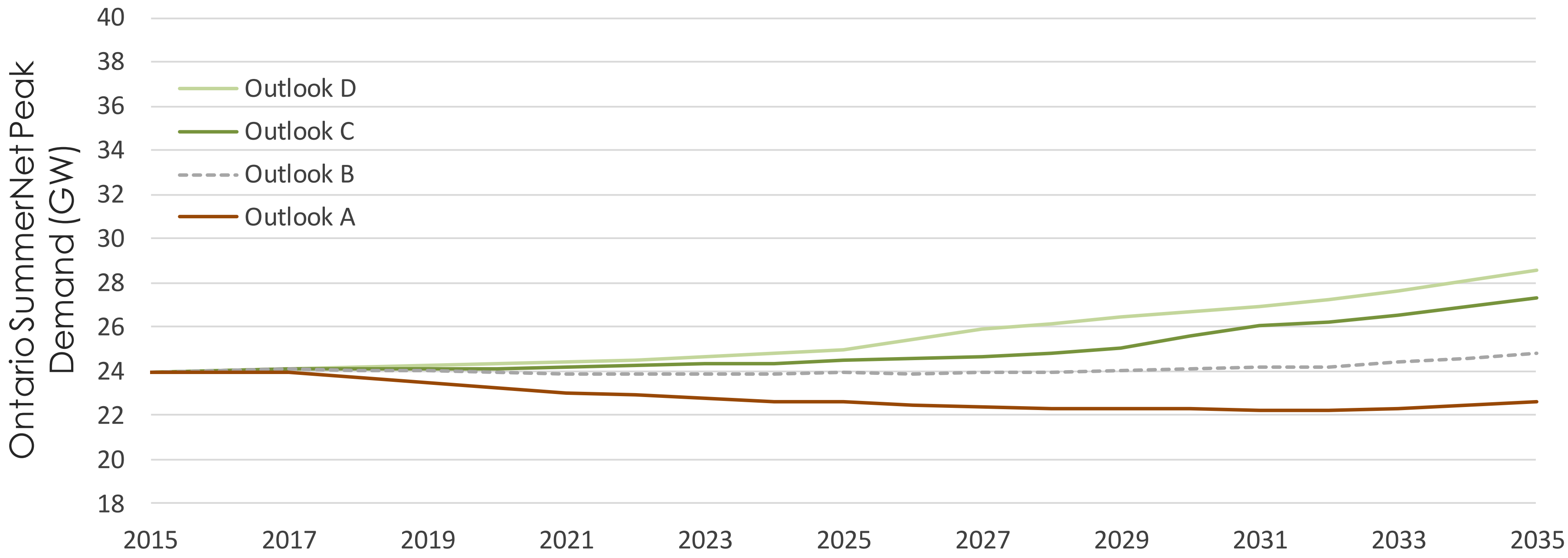


Data for Figure 8: Ontario Net Energy Demand across Demand Outlooks

Energy (TWh)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Outlook A	142.5	143.0	141.9	140.6	138.9	137.7	136.1	135.0	134.1	133.5	132.5
Outlook B	142.5	143.4	142.9	142.7	142.2	142.2	141.7	141.6	141.5	141.7	141.5
Outlook C	142.5	143.5	143.2	143.7	144.2	145.1	145.6	146.6	147.7	149.3	150.4
Outlook D	142.5	143.5	143.2	144.3	145.3	146.9	148.1	149.9	151.9	154.4	156.5

Energy (TWh)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Outlook A	131.7	131.2	131.0	130.8	130.7	130.7	131.0	131.5	132.3	133.4
Outlook B	141.2	141.5	142.1	142.4	142.8	143.3	144.0	145.0	146.3	147.8
Outlook C	151.7	153.5	155.9	158.0	160.5	163.1	166.2	169.4	173.1	177.1
Outlook D	158.8	161.7	165.3	168.6	172.4	176.3	181.0	185.6	191.0	196.7

Figure 9: Ontario Net Summer Peak Demand across Demand Outlooks

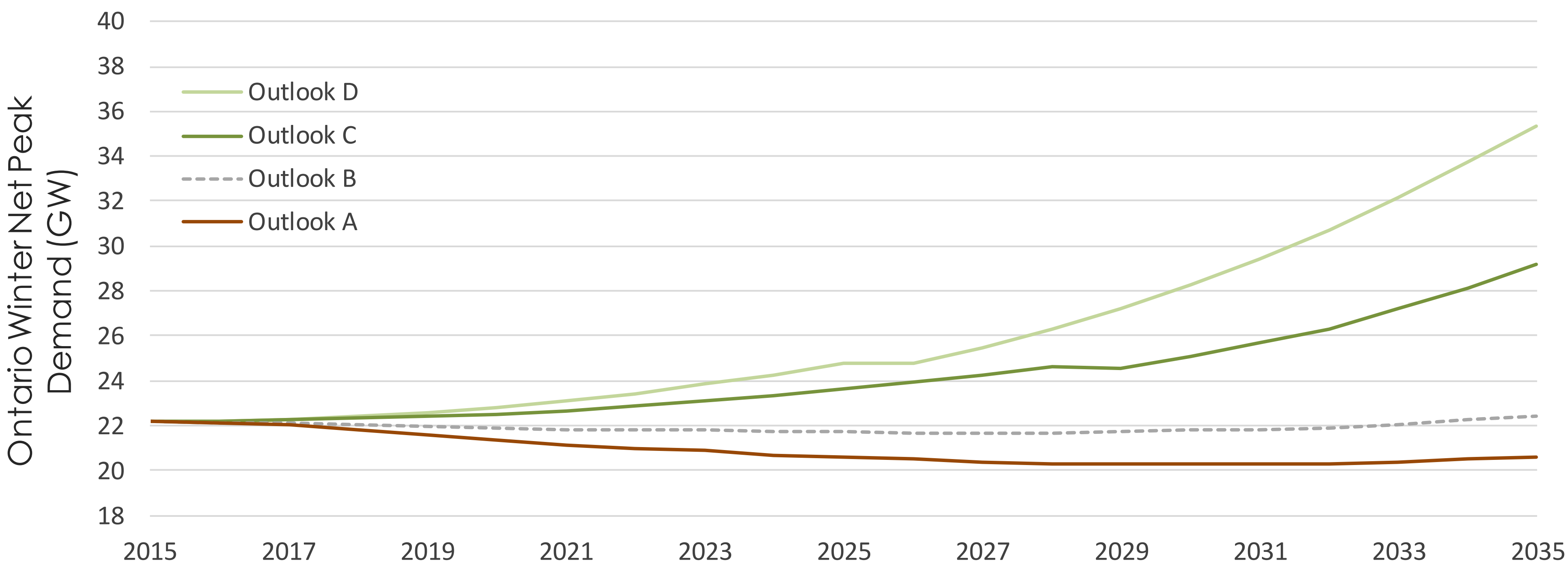


Data for Figure 9: Ontario Net Summer Peak Demand across Demand Outlooks

Summer Peak Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Outlook A	23,965	23,971	23,900	23,705	23,465	23,216	23,029	22,879	22,777	22,628	22,568
Outlook B	23,965	24,046	24,083	24,041	23,993	23,916	23,889	23,881	23,890	23,868	23,918
Outlook C	23,965	24,048	24,088	24,108	24,124	24,112	24,152	24,216	24,298	24,353	24,486
Outlook D	23,965	24,048	24,088	24,166	24,242	24,291	24,393	24,520	24,667	24,788	24,987

Summer Peak Demand (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Outlook A	22,453	22,372	22,295	22,292	22,258	22,231	22,198	22,317	22,436	22,586
Outlook B	23,882	23,918	23,940	24,030	24,082	24,133	24,171	24,369	24,568	24,792
Outlook C	24,549	24,680	24,804	25,049	25,550	26,022	26,199	26,551	26,902	27,276
Outlook D	25,446	25,921	26,124	26,410	26,667	26,937	27,197	27,633	28,071	28,532

Figure 10: Ontario Net Winter Peak Demand across Demand Outlooks



Data for Figure 10: Ontario Net Winter Peak Demand across Demand Outlooks

Winter Peak Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Outlook A	22,159	22,093	22,020	21,825	21,574	21,338	21,143	20,976	20,864	20,694	20,602
Outlook B	22,159	22,140	22,143	22,072	21,985	21,898	21,841	21,799	21,778	21,718	21,718
Outlook C	22,159	22,190	22,251	22,315	22,395	22,501	22,661	22,863	23,105	23,326	23,626
Outlook D	22,159	22,190	22,251	22,385	22,560	22,783	23,083	23,442	23,862	24,273	24,779

Winter Peak Demand (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Outlook A	20,483	20,394	20,315	20,316	20,295	20,282	20,260	20,375	20,488	20,622
Outlook B	21,659	21,668	21,672	21,746	21,794	21,844	21,875	22,052	22,229	22,422
Outlook C	23,911	24,265	24,633	24,513	25,085	25,695	26,330	27,185	28,144	29,167
Outlook D	24,742	25,492	26,277	27,226	28,296	29,451	30,683	32,158	33,716	35,379

Table 1: Assumptions across Demand Outlooks

Sector	Outlook A	Outlook B	Outlook C	Outlook D
Residential (52 TWh in 2015)	48 TWh in 2035	51 TWh in 2035	Oil heating switches to heat pumps, electric space and water heating gain 25% of gas market share (58 TWh in 2035)*	Oil heating switches to heat pumps, electric space and water heating gain 50% of gas market share (64TWh in 2035)
Commercial (51 TWh in 2015)	49 TWh in 2035	54 TWh in 2035	Oil heating switches to heat pumps, electric space and water heating gain 25% of gas market share (63 TWh in 2035)	Oil heating switches to heat pumps, electric space and water heating gain 50% of gas market share (69 TWh in 2035)
Industrial (35 TWh in 2015)	29 TWh in 2035	35 TWh in 2035	5% of 2012 fossil energy switches to electric equivalent (43 TWh in 2035)	10% of 2012 fossil energy switches to electric equivalent (51 TWh in 2035)
Electric Vehicles (<1 TWh in 2015)	2 TWh in 2035	3 TWh in 2035	2.4 million electric vehicles (EVs) by 2035 (8 TWh in 2035)	2.4 million EVs by 2035 (8 TWh in 2035)
Transit (<1 TWh in 2015)	1 TWh in 2035	1 TWh in 2035	Planned projects, 2017-2035 (1 TWh in 2035)	Planned projects, 2017-2035 (1 TWh in 2035)
Other**	5 TWh	5 TWh	5 TWh	5 TWh
Total* (143 TWh in 2015)**	**133 TWh in 2035**	**148 TWh in 2035**	**177 TWh in 2035**	**197 TWh in 2035**

Note: Outlooks C and D assume the same economic drivers as Outlook B.
* By 2035, of the number of natural gas fuelled space and water heating equipment being sold in Outlook B (due to existing equipment reaching end of life and new additions driven by growth in the residential and commercial sectors), 25 percent of this stock in Outlook C and 50 percent in Outlook D is replaced with air-source heat pumps.
** Others = Agriculture, Remote Communities, Generator Demand, IEI and Street Lighting
*** Total may not add up due to rounding

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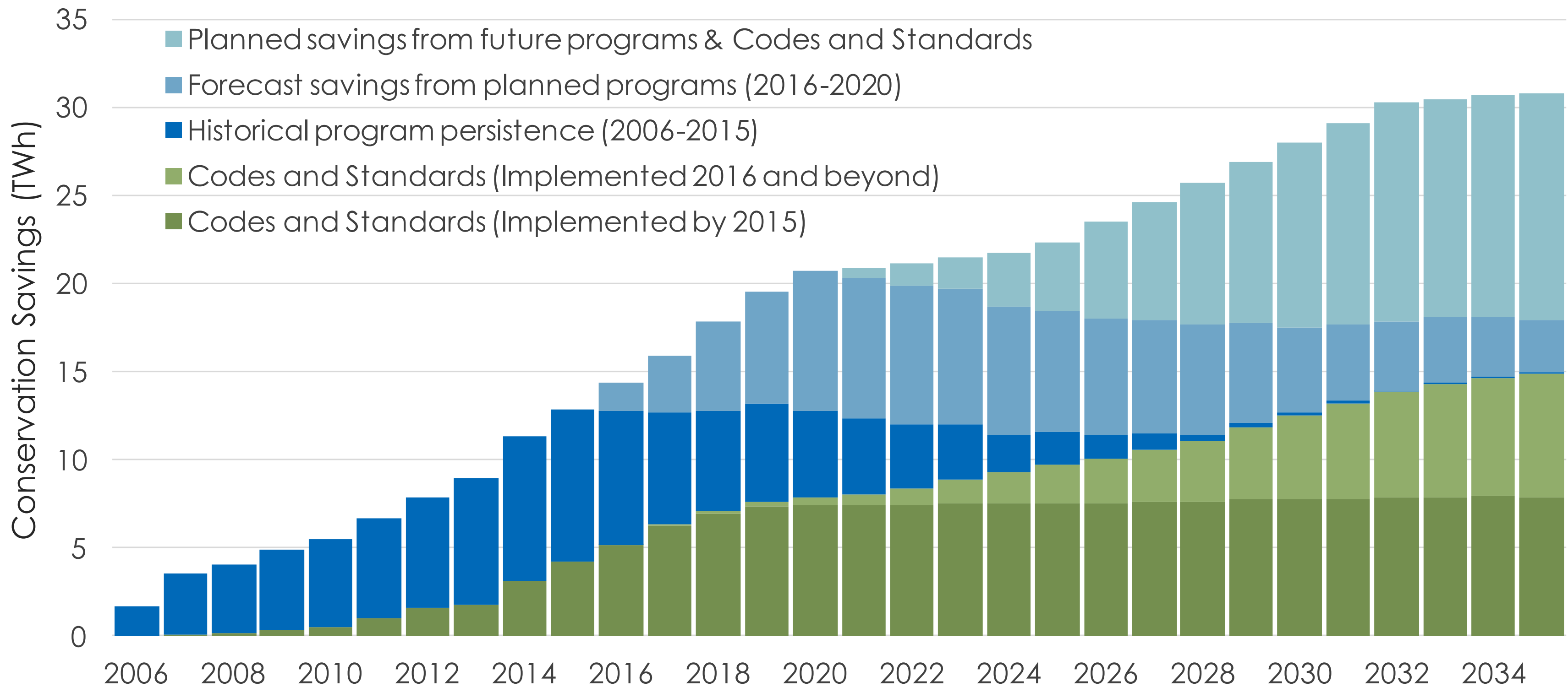
Figure 11: Conservation Achievement and Outlook to Meet the 2013 LTEP Target



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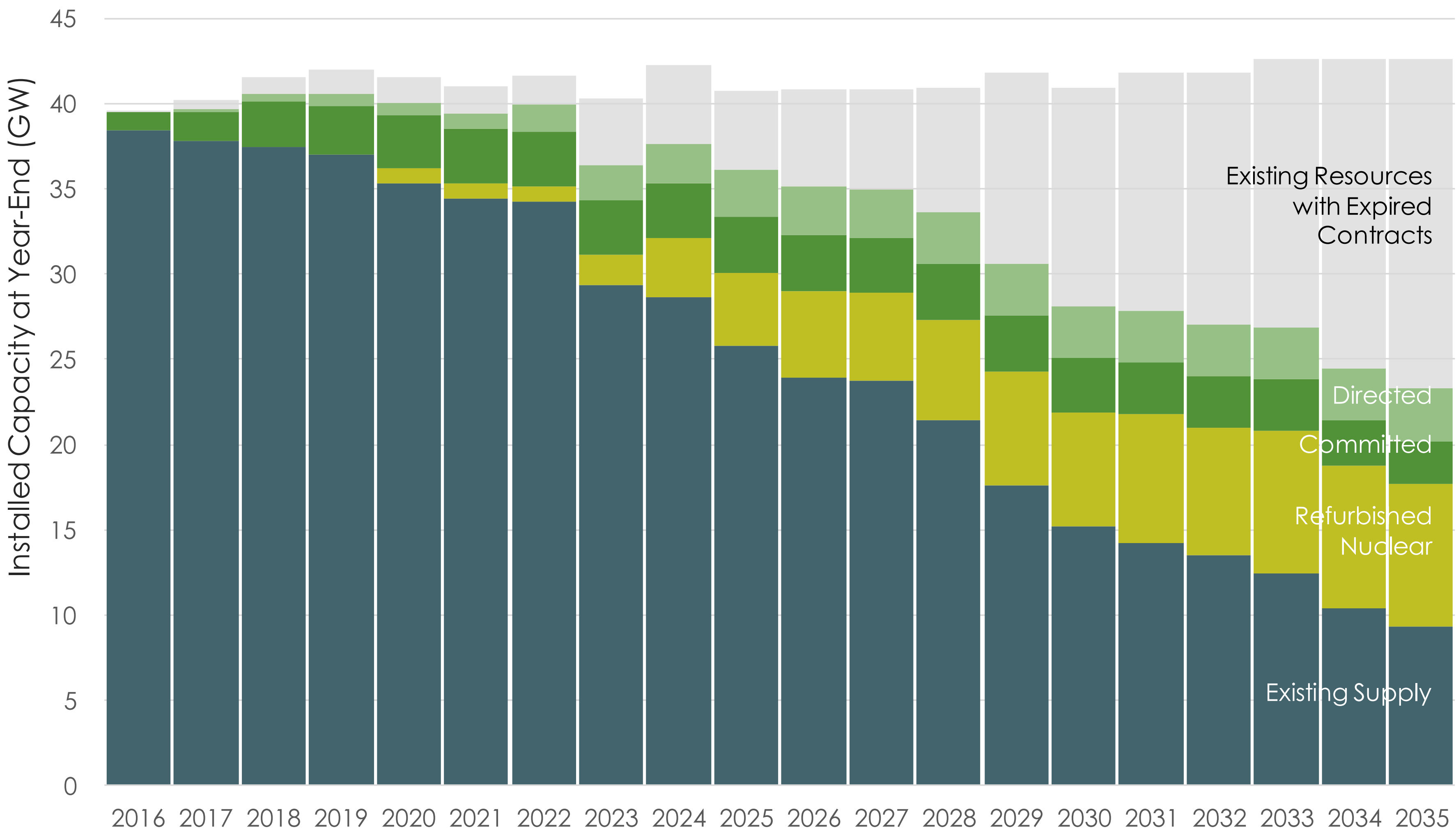
Data for Figure 11: Conservation Achievement and Outlook to Meet the 2013 LTEP Target

Savings (TWh)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Codes and Standards (Implemented by 2015)	-	0.1	0.2	0.3	0.5	1.0	1.6	1.8	3.1	4.2
Codes and Standards (Implemented 2016 and beyond)	-	-	-	-	-	-	-	-	-	-
Historical program persistence (2006-2015)	1.6	3.4	3.9	4.6	5.0	5.7	6.3	7.1	8.1	8.6
Forecast savings from planned programs (2016-2020)	-	-	-	-	-	-	-	-	-	-
Planned savings from future programs & Codes and Standards	-	-	-	-	-	-	-	-	-	-

Savings (TWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Codes and Standards (Implemented by 2015)	5.2	6.3	6.9	7.3	7.4	7.4	7.4	7.5	7.5	7.5
Codes and Standards (Implemented 2016 and beyond)	0.0	0.0	0.2	0.3	0.4	0.6	0.9	1.4	1.8	2.2
Historical program persistence (2006-2015)	7.5	6.4	5.7	5.5	4.9	4.4	3.6	3.1	2.1	1.9
Forecast savings from planned programs (2016-2020)	1.6	3.3	5.0	6.4	7.9	8.0	7.8	7.7	7.3	6.8
Planned savings from future programs & Codes and Standards	-	-	-	-	-	0.6	1.3	1.8	3.0	3.9

Savings (TWh)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Codes and Standards (Implemented by 2015)	7.5	7.6	7.6	7.7	7.8	7.8	7.8	7.8	7.9	7.9
Codes and Standards (Implemented 2016 and beyond)	2.6	3.0	3.4	4.1	4.8	5.4	6.0	6.4	6.7	7.0
Historical program persistence (2006-2015)	1.4	0.9	0.4	0.3	0.1	0.1	0.1	0.0	0.0	0.0
Forecast savings from planned programs (2016-2020)	6.6	6.4	6.2	5.7	4.8	4.3	4.0	3.7	3.4	3.0
Planned savings from future programs & Codes and Standards	5.5	6.7	8.1	9.1	10.5	11.5	12.4	12.4	12.6	12.8

Figure 12: Outlook for Installed Capacity to 2035

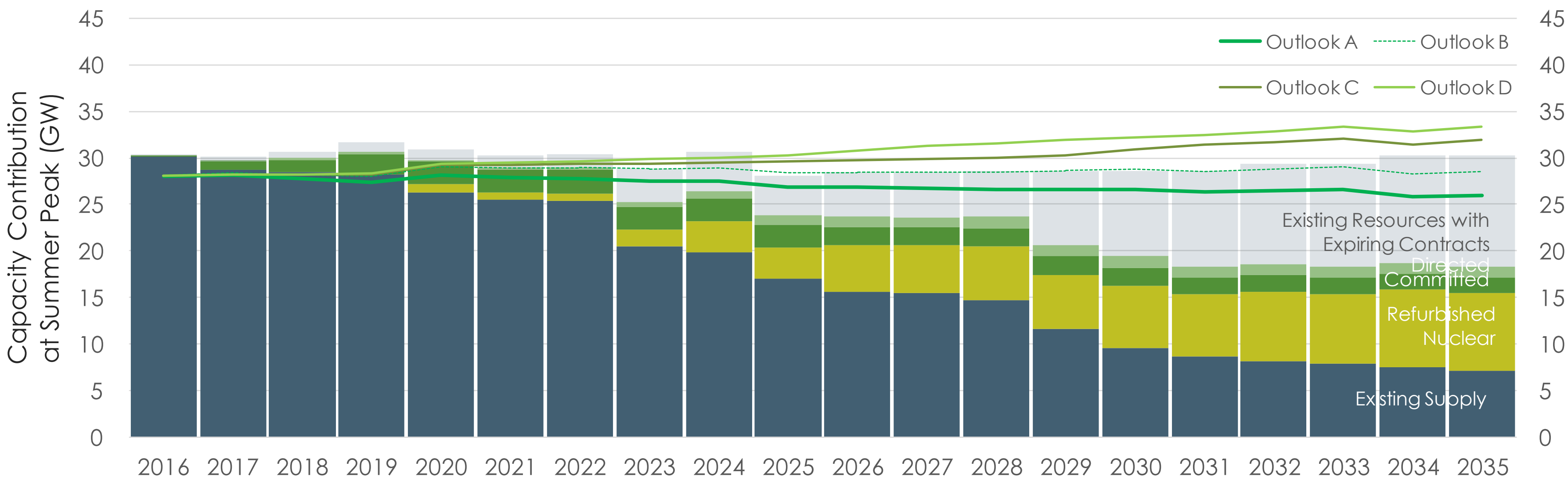


Data for Figure 12: Outlook for Installed Capacity to 2035

Installed Capacity (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Existing Supply	38,417	37,868	37,510	37,056	35,307	34,425	34,288	29,405	28,620	25,756
Committed, Not Yet Online	1,078	1,678	2,655	2,811	3,194	3,194	3,230	3,229	3,244	3,244
Directed Procurements	0	125	433	683	683	963	1,563	2,047	2,287	2,767
Expired Contracts	32	581	939	1,492	1,548	1,548	1,684	3,875	4,661	4,689
Refurbished Nuclear	0	0	0	0	881	881	881	1,762	3,465	4,346

Installed Capacity (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Existing Supply	23,903	23,789	21,440	17,599	15,155	14,254	13,471	12,443	10,401	9,345
Committed, Not Yet Online	3,244	3,244	3,244	3,239	3,238	3,021	3,021	2,991	2,696	2,517
Directed Procurements	2,855	2,855	3,033	3,033	3,033	3,033	3,033	3,033	3,033	3,033
Expired Contracts	5,719	5,832	7,376	11,221	12,843	13,961	14,744	15,803	18,140	19,375
Refurbished Nuclear	5,127	5,127	5,900	6,722	6,722	7,544	7,544	8,366	8,366	8,366

Figure 13a: Available Supply at the Time of Peak Demand Relative to Total Resource Requirements (Summer)



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Data for Figure 13a: Available Supply at the Time of Peak Demand Relative to Total Resource Requirements (Summer)

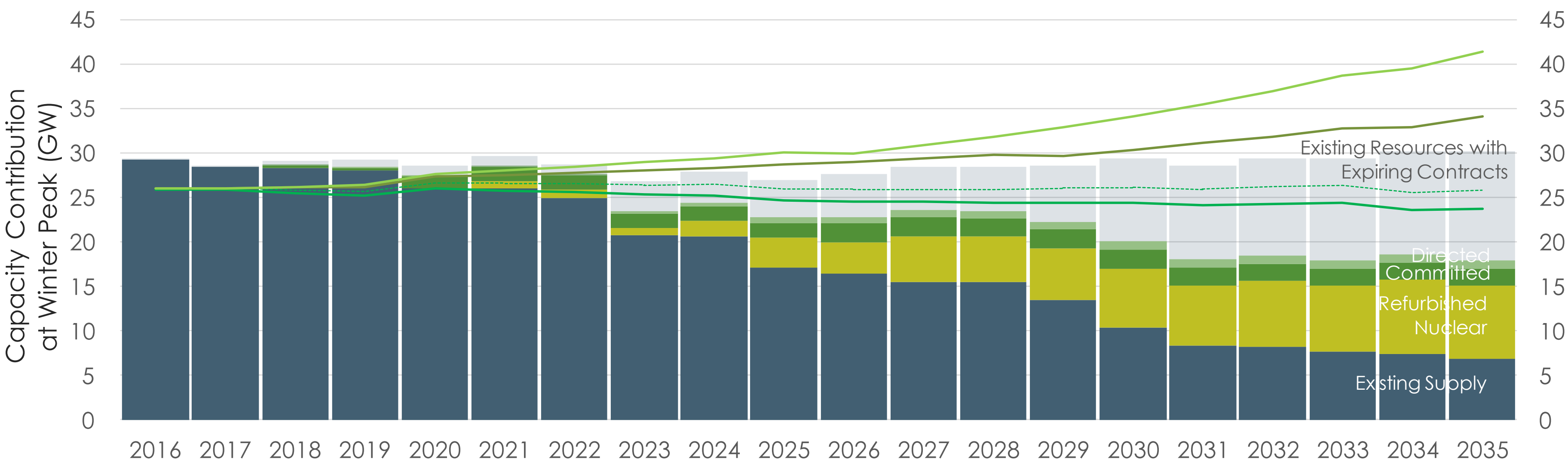
Capacity Contribution at Summer Peak (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Existing Supply	30,122	28,724	28,477	28,198	26,336	25,456	25,337	20,497	19,793	16,951
Refurbished Nuclear	0	0	0	0	878	878	878	1,756	3,453	3,453
Committed, Not Yet Online	183	899	1,305	2,147	2,360	2,427	2,451	2,451	2,452	2,452
Directed Procurements	0	17	199	318	136	255	315	559	752	993
Expired Contracts	31	477	725	1,087	1,252	1,263	1,381	3,560	4,265	4,276

Capacity Contribution at Summer Peak (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Existing Supply	15,558	15,510	14,666	11,601	9,596	8,682	8,128	7,904	7,503	7,145
Refurbished Nuclear	5,084	5,084	5,851	5,851	6,670	6,670	7,488	7,488	8,307	8,307
Committed, Not Yet Online	1,952	1,952	1,952	1,950	1,949	1,823	1,752	1,746	1,726	1,701
Directed Procurements	1,056	1,056	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176
Expired Contracts	4,850	4,898	4,940	8,009	9,195	10,235	10,861	11,091	11,511	11,894

Resource Requirement at Summer Peak (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Outlook A	28,070	28,130	27,711	27,383	28,186	27,944	27,769	27,649	27,475	26,953
Outlook B	28,157	28,345	28,104	28,000	29,006	28,950	28,941	28,951	28,925	28,505
Outlook C	28,137	28,183	28,207	28,225	29,212	29,258	29,332	29,429	29,493	29,648
Outlook D	28,137	28,183	28,275	28,363	29,421	29,540	29,689	29,861	30,002	30,235

Resource Requirement at Summer Peak (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Outlook A	26,821	26,728	26,639	26,636	26,597	26,565	26,527	26,664	25,802	25,973
Outlook B	28,465	28,505	28,531	28,635	28,694	28,753	28,796	29,024	28,253	28,510
Outlook C	29,723	29,876	30,021	30,307	30,894	31,445	31,653	32,065	31,476	31,912
Outlook D	30,772	31,327	31,566	31,900	32,200	32,517	32,821	33,331	32,843	33,383

Figure 13b: Available Supply at the Time of Peak Demand Relative to Total Resource Requirements (Winter)



Data for Figure 13b: Available Supply at the Time of Peak Demand Relative to Total Resource Requirements (Winter)

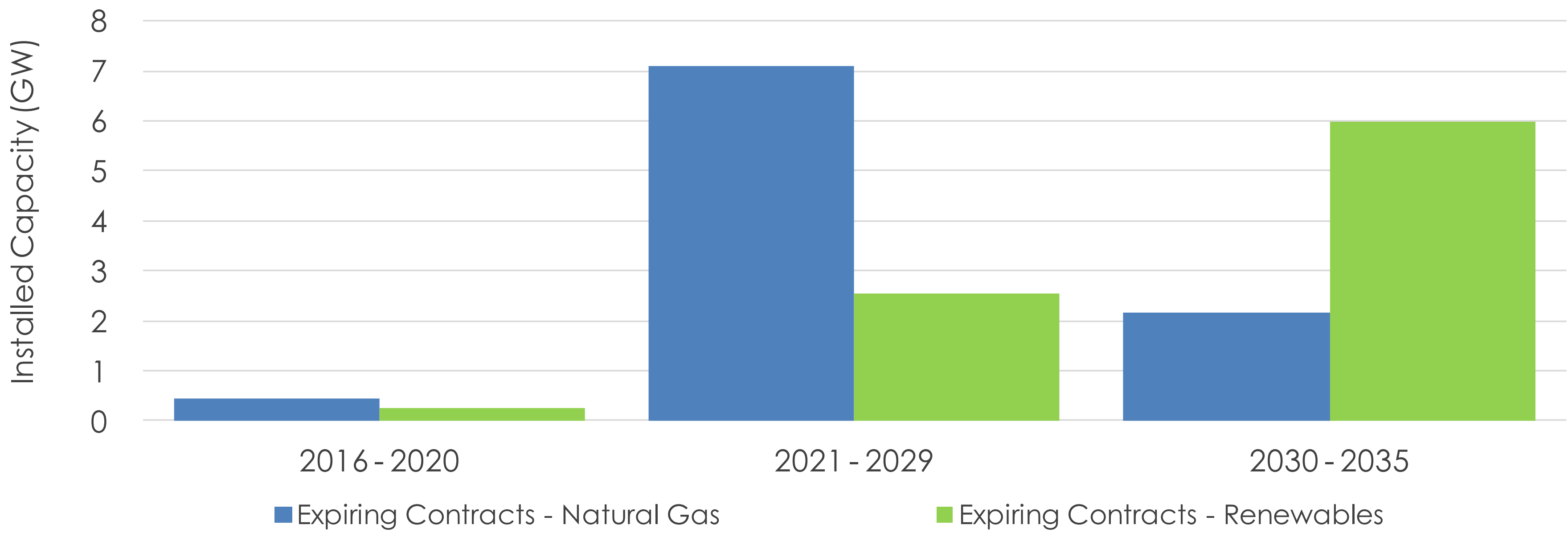
Capacity Contribution at Winter Peak (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Existing Supply	29,268	28,448	28,239	27,981	26,020	25,980	24,983	20,696	20,649	17,057
Refurbished Nuclear	0	0	0	0	0	878	878	878	1,756	3,453
Committed, Not Yet Online	0	0	314	349	1,279	1,587	1,587	1,614	1,613	1,617
Directed Procurements	0	0	2	99	157	8	49	200	367	573
Expired Contracts	31	151	512	769	1,100	1,149	1,267	3,408	3,456	4,216

Capacity Contribution at Winter Peak (MW)	2,026	2,027	2,028	2,029	2,030	2,031	2,032	2,033	2,034	2,035
Existing Supply	16,459	15,525	15,471	13,385	10,337	8,366	8,128	7,633	7,384	6,814
Refurbished Nuclear	3,453	5,084	5,084	5,851	6,670	6,670	7,488	7,488	8,307	8,307
Committed, Not Yet Online	2,117	2,117	2,117	2,114	2,113	2,113	1,906	1,902	1,895	1,790
Directed Procurements	741	807	791	936	936	936	936	936	936	936
Expired Contracts	4,815	4,929	5,000	6,271	9,320	10,472	10,917	11,416	11,672	12,347

Resource Requirement at Winter Peak (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Outlook A	25,870	25,917	25,514	25,176	25,987	25,737	25,542	25,411	25,212	24,693
Outlook B	25,926	26,063	25,802	25,657	26,643	26,554	26,505	26,480	26,411	25,975
Outlook C	25,962	26,033	26,108	26,202	27,326	27,514	27,749	28,033	28,292	28,643
Outlook D	25,962	26,033	26,191	26,395	27,656	28,007	28,428	28,918	29,399	29,992

Resource Requirement at Winter Peak (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Outlook A	24,555	24,453	24,363	24,364	24,339	24,325	24,299	24,431	23,561	23,715
Outlook B	25,908	25,919	25,922	26,008	26,063	26,120	26,156	26,359	25,563	25,785
Outlook C	28,976	29,390	29,820	29,680	30,349	31,063	31,806	32,806	32,928	34,125
Outlook D	29,948	30,826	31,745	32,854	34,106	35,457	36,899	38,625	39,448	41,393

Figure 14: Installed Capacity of Future Contract Expirations



Data for Figure 14: Installed Capacity of Future Contract Expirations

(MW)	2016 - 2020	2021 - 2029	2030 - 2035
Expiring Contracts - Natural Gas	449	7,106	2,161
Expiring Contracts - Renewables	238	2,550	5,993
TOTAL	*687*	*9,656*	*8,154*

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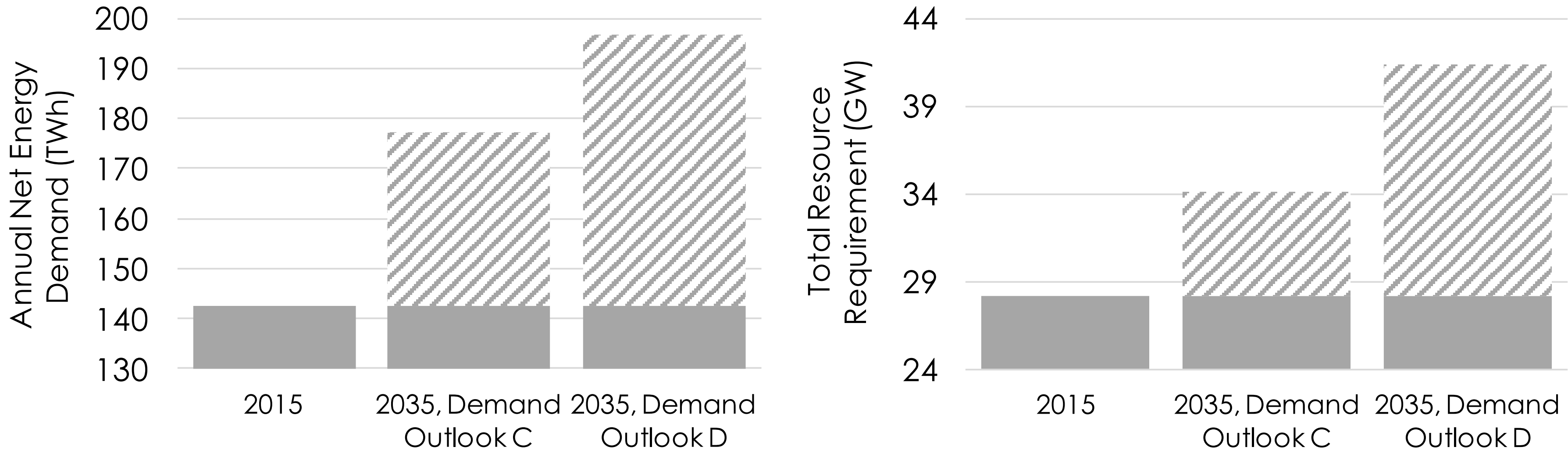
Figure 15: Electricity Supply Requirements in Outlooks C and D



Data for Figure 15: Electricity Supply Requirements in Outlooks C and D

	2015	2035, Outlook C	2035, Outlook D
Annual Energy (TWh)	142.5	177.1	196.7
Total Resource Requirement (MW)	28,157	34,125	41,393

Table 2: Current Technology Characteristics

	Capacity	Energy	Operating Reserve	Load Following	Frequency Regulation	Capacity Factor	Contribution to Winter Peak	Contribution to Summer Peak	LUEC ($/MWh)
Conservation	Yes	Yes	No	No	No	Depends on Measure	Depends on Measure	Depends on Measure	$30-50
Demand Response	Yes	No	Yes	Yes	Limited	N/A	60-70%	80-85%	N/A
Solar PV	Limited	Yes	No	Limited	No	15%	3-5%	20-35%	$140-290
Wind	Limited	Yes	No	Limited	No	30-40%	20-30%	11%	$65-210
Bioenergy	Yes	Yes	Yes	Limited	No	40-80%	85-90%	85-90%	$160-260
Storage	Yes	No	Yes	Yes	Yes	Depends on technology/ application	Depends on technology/ application	Depends on technology/ application	Depends on technology/ application
Waterpower	Yes	Yes	Yes	Yes	Yes	30-70%	67-75%	63-71%	$120-240
Nuclear	Yes	Yes	No	Limited	No	70-95%	90-95%	95-99%	$120-290
Natural Gas	Yes	Yes	Yes	Yes	Yes	up to 65%	95%	89%	$80-310

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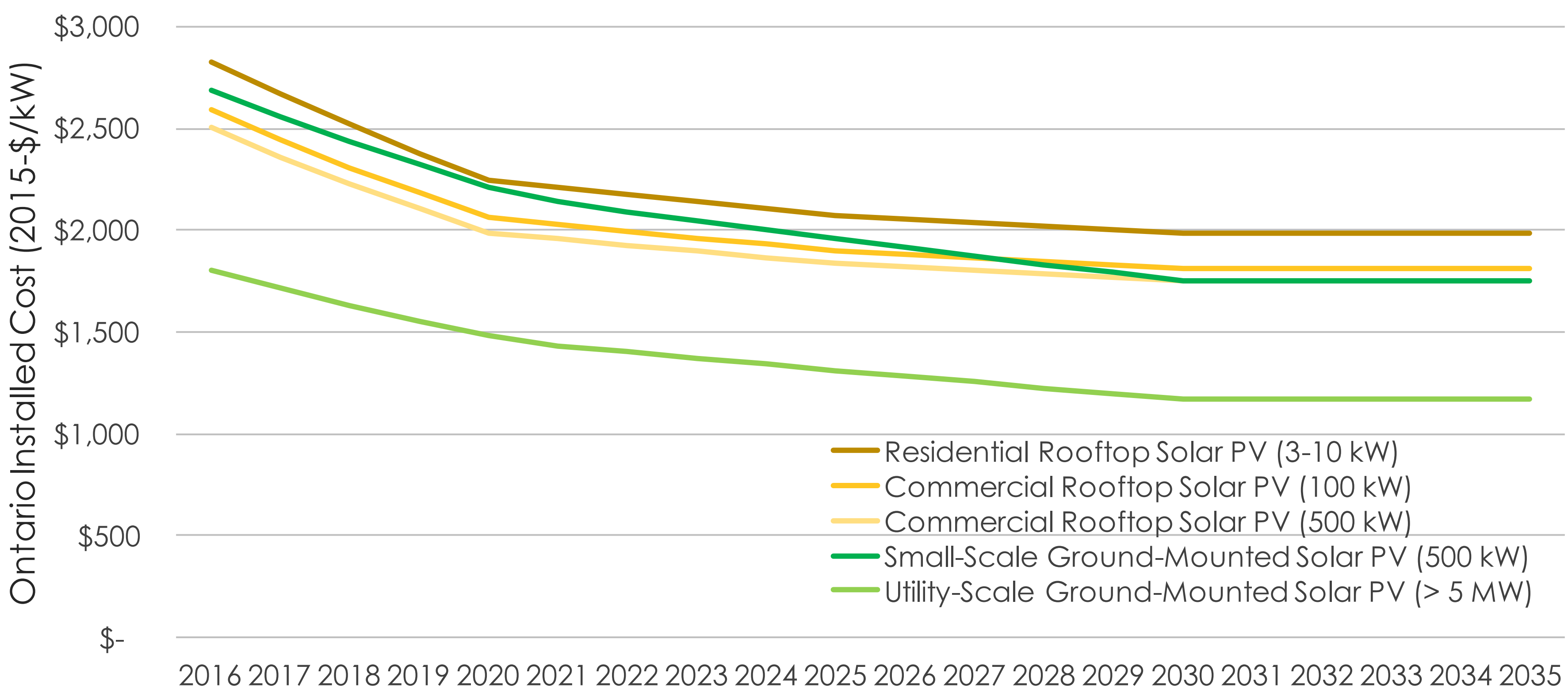
Figure 16: Installed Solar PV Cost Projections in Ontario



Data for Figure 16: Installed Solar PV Cost Projections in Ontario

Installed Cost ($/kW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential Rooftop Solar PV (3-10 kW)	2,828	2,670	2,521	2,380	2,246	2,211	2,176	2,142	2,109	2,075
Commercial Rooftop Solar PV (100 kW)	2,592	2,447	2,310	2,181	2,059	2,026	1,995	1,963	1,932	1,902
Commercial Rooftop Solar PV (500 kW)	2,502	2,362	2,230	2,105	1,987	1,956	1,926	1,895	1,866	1,836
Small-Scale Ground-Mounted Solar PV (500 kW)	2,689	2,560	2,437	2,320	2,209	2,140	2,092	2,046	2,000	1,956
Utility-Scale Ground-Mounted Solar PV (> 5 MW)	1,800	1,714	1,631	1,553	1,478	1,432	1,400	1,369	1,339	1,309

Installed Cost ($/kW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential Rooftop Solar PV (3-10 kW)	2,056	2,037	2,018	1,999	1,981	1,981	1,981	1,981	1,981	1,981
Commercial Rooftop Solar PV (100 kW)	1,884	1,867	1,850	1,832	1,815	1,815	1,815	1,815	1,815	1,815
Commercial Rooftop Solar PV (500 kW)	1,819	1,802	1,785	1,769	1,752	1,752	1,752	1,752	1,752	1,752
Small-Scale Ground-Mounted Solar PV (500 kW)	1,914	1,872	1,832	1,792	1,753	1,753	1,753	1,753	1,753	1,753
Utility-Scale Ground-Mounted Solar PV (> 5 MW)	1,281	1,253	1,226	1,199	1,173	1,173	1,173	1,173	1,173	1,173

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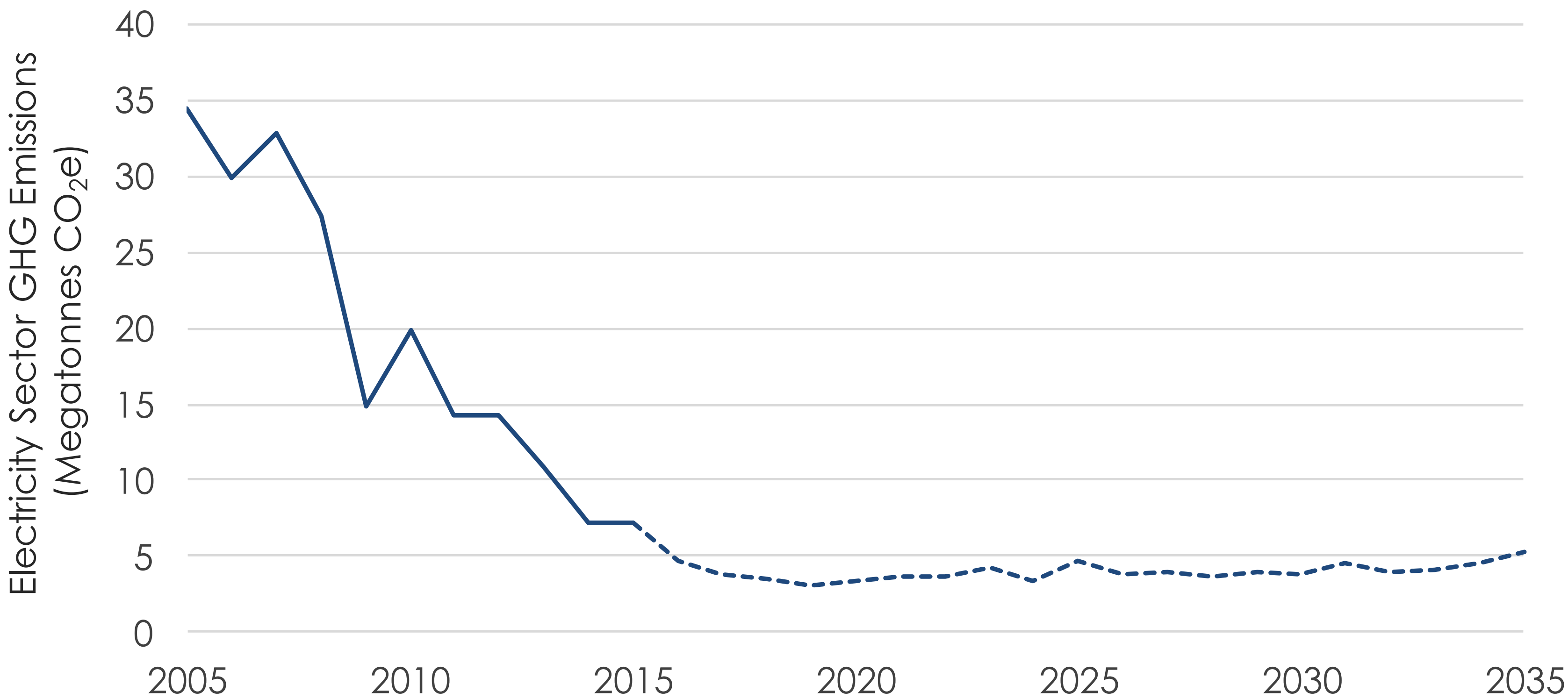
Figure 17: Existing Interconnections

Table 3: Status and Drivers of Transmission Projects in Outlook B

Projects	Status	Drivers			
		Maintaining Bulk System Reliability	Addressing Regional Reliability and Adequacy Needs	Achieving 2013 Long-Term Energy Plan (LTEP) Policy Objectives	Facilitating Interconnections with Neighbouring Jurisdictions
East-West Tie Expansion	Expected to be in service in 2020	X		X	
Line to Pickle Lake	Plan is complete; Expected to be in service in early 2020.		X	X	
Remote Community Connection Plan	Draft technical report released; development work underway for connection of 16 communities; engagement with communities is ongoing.		X	X	
Northwest Bulk Transmission Line	Hydro One is carrying out early development work to maintain the viability of the option.	X		X	
Supply to Essex County Transmission Reinforcement	Expected In-service date of 2018		X		
West GTA Bulk reinforcement	Plan is being finalized.	X			
Guelph Area Transmission Refurbishment	Expected to be in service in 2016		X		
Remedial Action Scheme (RAS) in Bruce and Northwest	Under development. Northwest RAS targeted for late 2016 in-service; Bruce RAS early 2017	X			
Clarington 500/230kV transformers	Expected to be in service in 2018	X			
Ottawa Area Transmission Reinforcement	Project has been initiated; expected to be in service 2020.		X		X
Richview to Manby Transmission Reinforcement	Expected to be in service in 2020		X		

Figure 18: Electricity Sector GHG Emissions in Outlook B



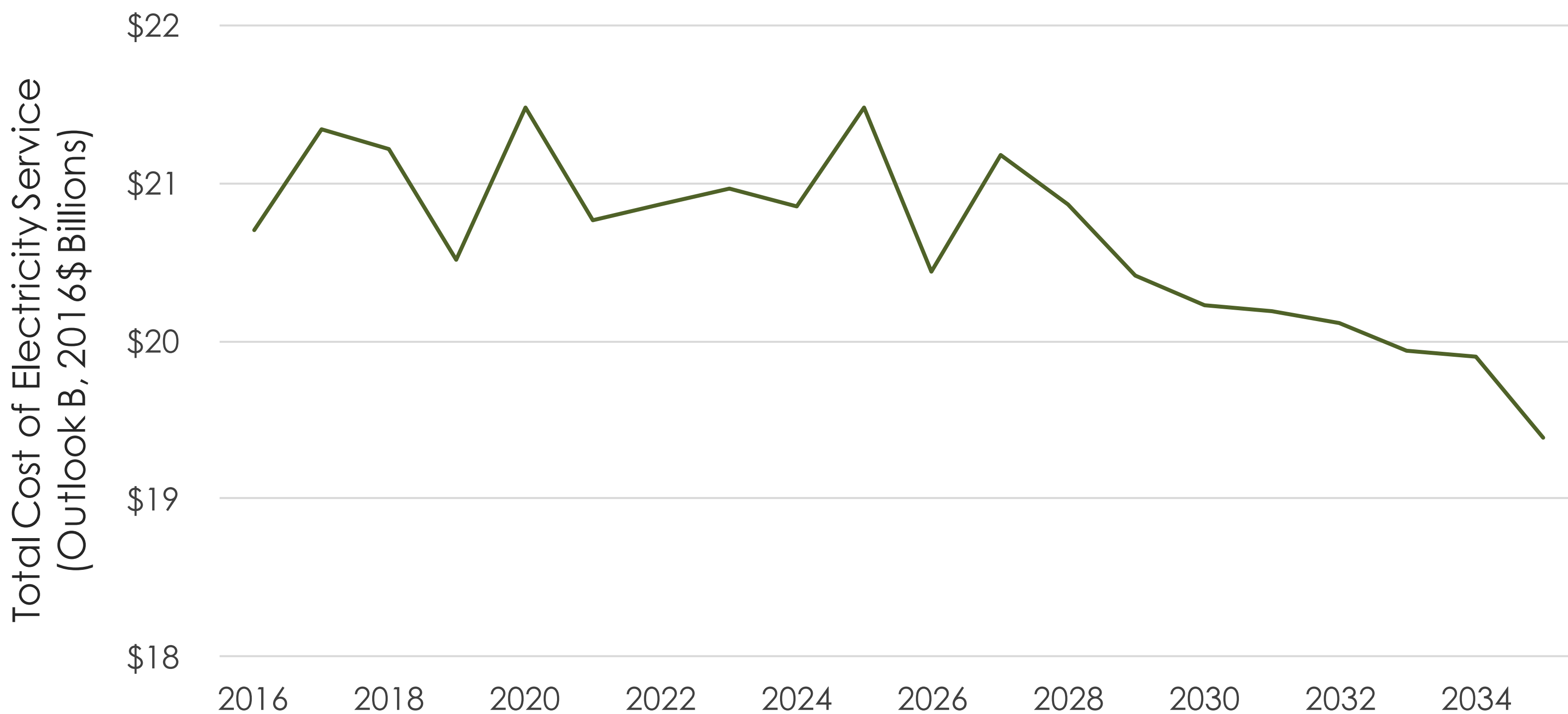
Data for Figure 18: Electricity Sector GHG Emissions in Outlook B

MT CO2e	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Electricity Sector GHG Emissions	34.5	29.9	32.9	27.4	14.9	19.8	14.2	14.2	10.9	7.1	7.1

MT CO2e	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast GHG Emissions (Outlook B)	4.6	3.8	3.5	3.1	3.4	3.6	3.7	4.2	3.4	4.7

MT CO2e	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Forecast GHG Emissions (Outlook B)	3.8	3.9	3.7	3.9	3.8	4.5	4.0	4.2	4.6	5.3

Figure 19: Total Cost of Electricity Service in Outlook B



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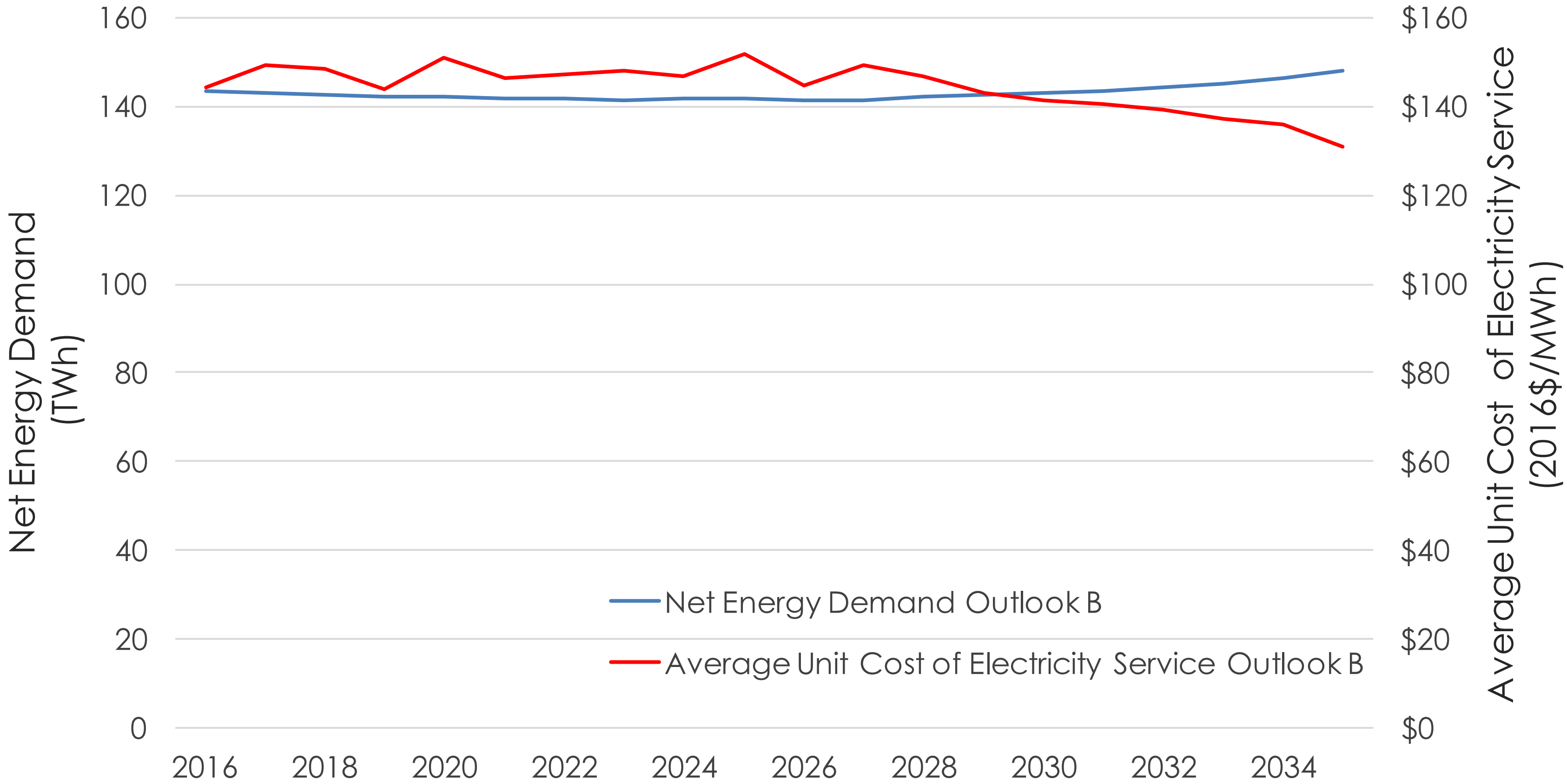
Data for Figure 19: Total Cost of Electricity Service in Outlook B

Total Cost of Electricity Service (2016$ Billions)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Outlook B	20.7	21.3	21.2	20.5	21.5	20.8	20.9	21.0	20.9	21.5

Total Cost of Electricity Service (2016$ Billions)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Outlook B	20.4	21.2	20.9	20.4	20.2	20.2	20.1	19.9	19.9	19.4

Figure 20: Average Unit Cost of Electricity Service in Outlook B



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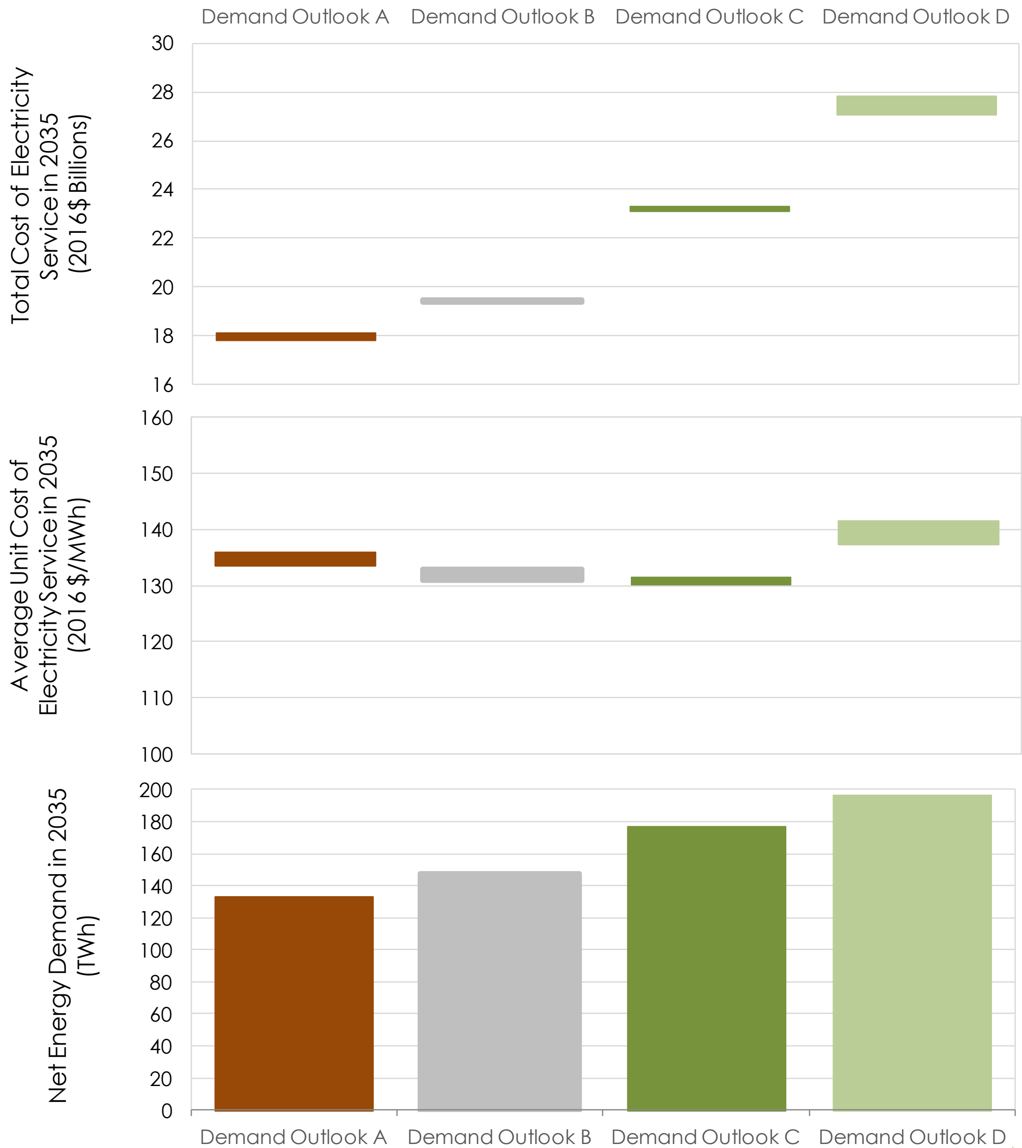
Data for Figure 20: Average Unit Cost of Electricity Service in Outlook B

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Demand Outlook - B (TWh)	143.5	143.0	142.8	142.4	142.4	141.9	141.7	141.6	141.9	141.7
Average Unit Cost - B (2016$/MWh)	144.3	149.2	148.6	144.1	150.9	146.4	147.2	148.0	147.0	151.7

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Outlook - B (TWh)	141.4	141.6	142.2	142.5	143.0	143.4	144.2	145.1	146.5	148.0
Average Unit Cost - B (2016$/MWh)	144.6	149.5	146.8	143.3	141.4	140.8	139.5	137.4	135.9	131.0

Figure 21: Cost of Electricity Service across Demand Outlooks



Data for Figure 21: Cost of Electricity Service across Demand Outlooks

	Outlook A	Outlook B	Outlook C	Outlook D
Minimum System Cost (2016$ Billions)	17.8	19.4	23.1	27.1
Maximum System Cost (2016$ Billions)	18.2	19.4	23.3	27.9
Minimum Unit Cost (2016$/MWh)	134	131	130	137
Maximum Unit Cost (2016$/MWh)	136	131	132	142
Energy Demand in 2035 (TWh)	133	148	177	197

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LTEP: Comparison of 2014 Forecast vs. 2014 Actual Results

December 2015

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Purpose

- The Ministry of Energy released Ontario’s updated Long-Term Energy Plan (2013 LTEP) in December 2013
- The former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), developed a series of technical modules (available here) that describe the methodologies and assumptions used in the development of the 2013 LTEP
- The 2013 LTEP committed to annual reporting to update the public on changing supply and demand conditions and to track the progress to date on the 2013 LTEP forecasts
- The purpose of this module is to provide a comparison of the 2013 LTEP forecast to actual 2014 results

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Outline

- This module compares the 2013 LTEP forecasts to 2014 actual results in the following order:
  - Demand (net of conservation)
    - Energy demand
    - Peak demand
  - Conservation
    - Energy demand savings
    - Demand response
  - Generation supply
    - Installed capacity
    - Energy production
  - Cost of electricity service
    - Total cost of electricity service
    - Unit cost of electricity service
  - Emissions
    - Greenhouse gas emissions (CO_2)
    - Air contaminants: nitrogen oxides (NO_x), sulphur oxides (SO_x) and particulate matter ($PM_{2.5}$) emissions

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Summary of Results: 2014 Actual vs. 2014 Forecast in 2013 LTEP

- **Demand (net of conservation)**
  - 2014 weather-corrected energy demand is 3.7 TWh (2.6%) higher than forecast
  - 2014 weather-corrected peak demand (winter) is 773 MW (-3.3%) lower than forecast (summer)
  - The 2014 actual peak occurred on January 7. The peak was forecasted for a summer workday afternoon.

- **Conservation**
  - Total energy savings between 2006 and 2014 are 9.9 TWh, about 200 GWh (-2%) lower than forecast
  - Demand response resources totaled 1,589 MW in 2014, about 200 MW higher than forecast; this is largely driven by higher peak reduction savings from the Industrial Conservation Initiative (ICI)

- **Generation supply**
  - 2014 actual installed capacity is below the forecast by about 0.4 GW (-1%)
  - 2014 actual energy production is higher than forecast by 9 TWh (5.8%) because of higher market demand

- **Cost of electricity service**
  - The 2014 total cost for electricity service is lower by $0.4 billion (-2%) than forecast, due to lower conservation, distribution and generation costs. These are partially offset by higher transmission, wholesale market charges and the Debt Retirement Charge.
  - 2014 actual unit cost of electricity service is lower than forecast by 5% due to higher actual demand than forecast

- **Emissions**
  - 2014 preliminary actual CO_2 emissions are approximately 1.4 MT greater than forecast. This difference is attributable to higher demand and greater coal and gas production
  - 2014 actual NOx and SOx are higher than forecast; actual $PM_{2.5}$ is lower than forecast

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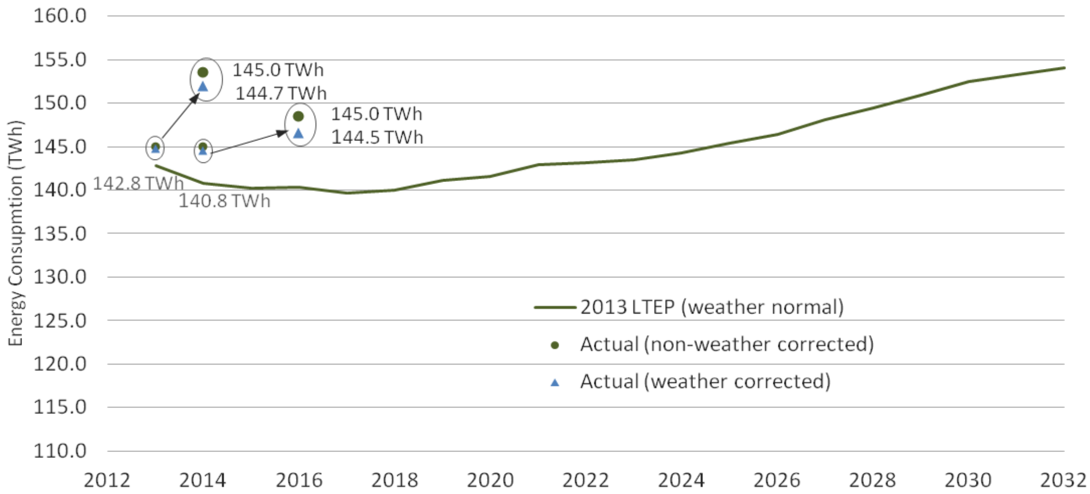
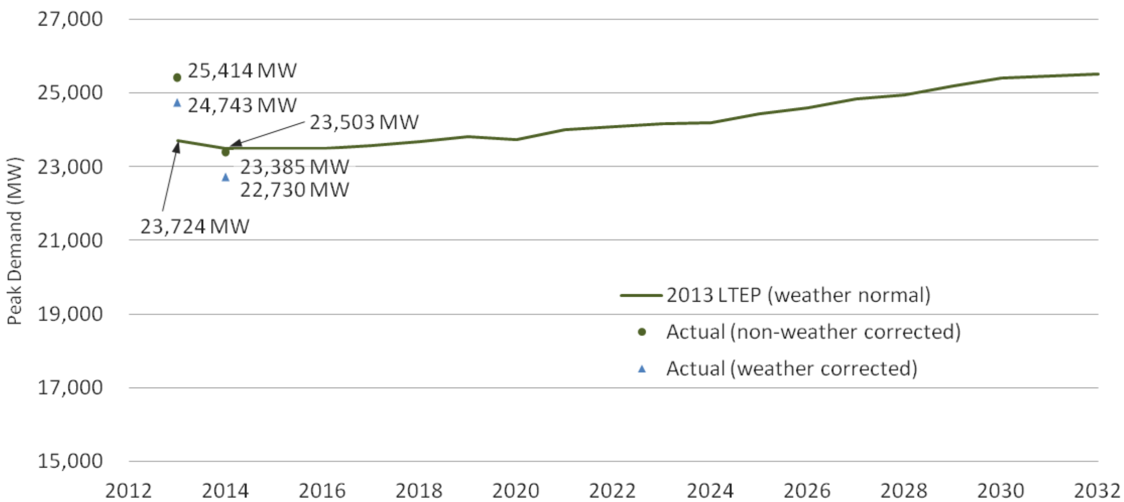
Results:
2014 Actual compared to 2014 Forecast in 2013 LTEP

Energy and peak demand





Notes:

- 2013 LTEP energy demand and peak demand are weather normal and net of conservation and peak demand savings.
- The actual and forecasted energy demand and peak demand include impacts of distributed generation.

Results:

- 2014 actual energy demand (weather corrected) was 3.7 TWh (2.6%) higher than projected in the 2013 LTEP (weather normal)
- 2014 actual peak demand (weather corrected) was 773 MW (-3.3%) lower than projected in the 2013 LTEP (weather normal)
- In the 2013 LTEP it was assumed peak would occur in the summer; however, the actual peak in 2014 occurred on January 7, 2014
- Non weather-corrected energy and peak demand actuals in 2014 were higher than weather-corrected data by 0.5 TWh (0.3%) and 661 MW (3%), respectively

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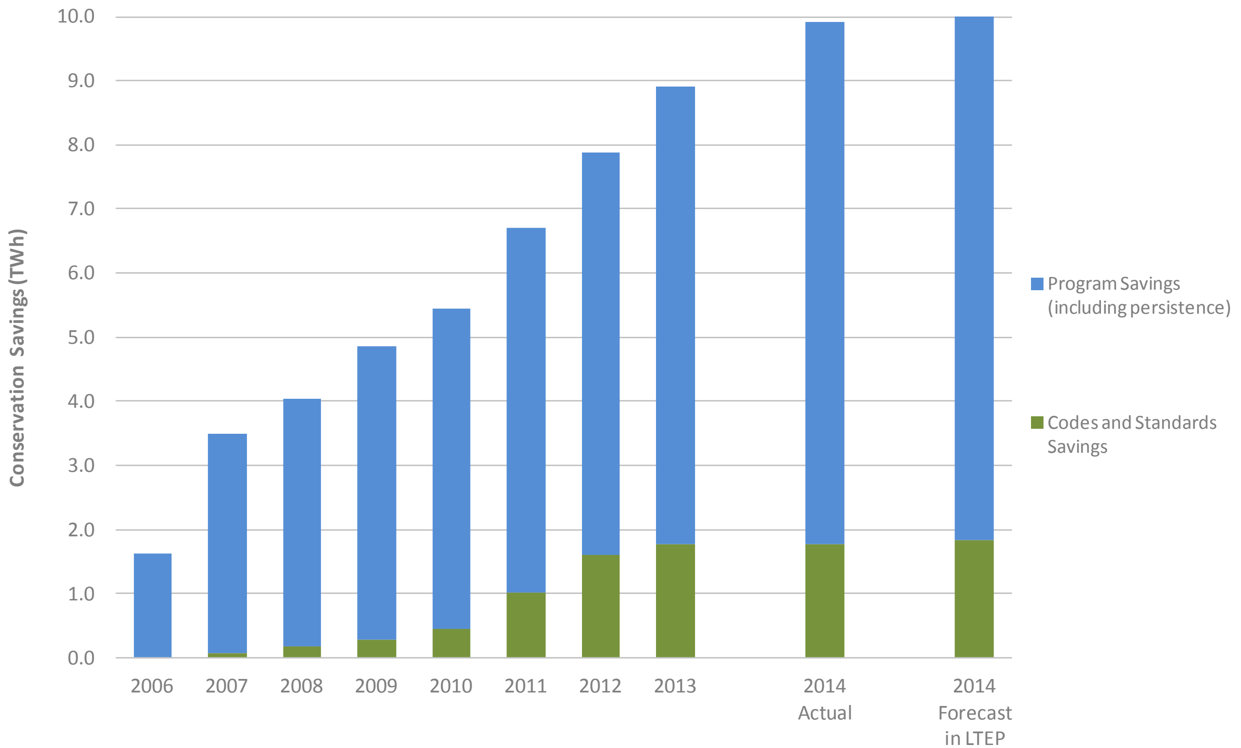
Conservation energy savings



Results:

- Total energy savings between 2006 and 2014 are 9.9 TWh, which is about 200 GWh (-2%) lower than the 2013 LTEP forecast

Notes:

- Savings are at the generator level, and include transmission and distribution losses
- Savings from conservation programs are between 2006 and 2014 including persistence. Savings from codes and standards are between 2006 and 2013 and assume the same as forecast in LTEP. Forecast new 2014 savings from codes and standards are not included. Evaluation of savings from codes and standards is under way.

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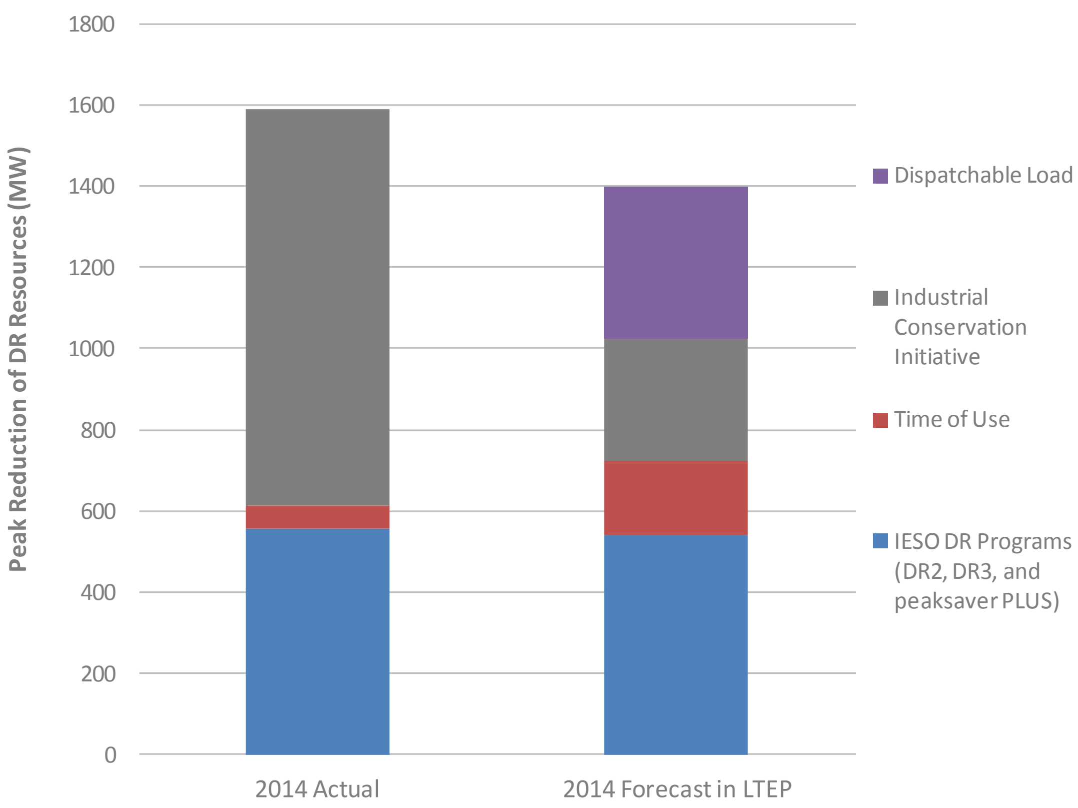
Demand management



Results:

- Demand management resources totaled 1,589 MW in 2014, about 200 MW (14%) higher than forecast
- This is largely driven by higher peak reduction savings from the Industrial Conservation Initiative (ICI)

Notes:

- The IESO DR programs (DR2, DR3 and *peaksaver*PLUS) reported a total demand saving of 555 MW, which is ex ante load impact.
- Time-of-use peak reduction is from the IESO's evaluation.
- ICI impact is the IESO's estimate on peak days of 2014.

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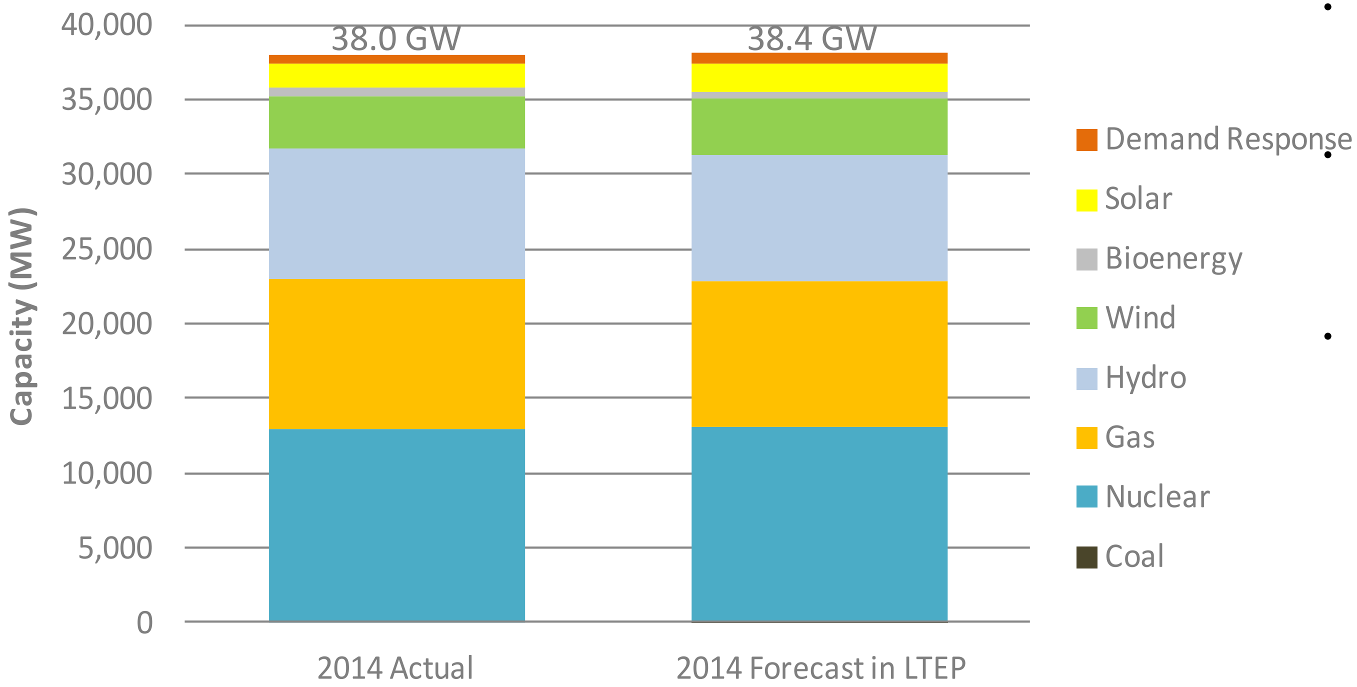
Installed capacity



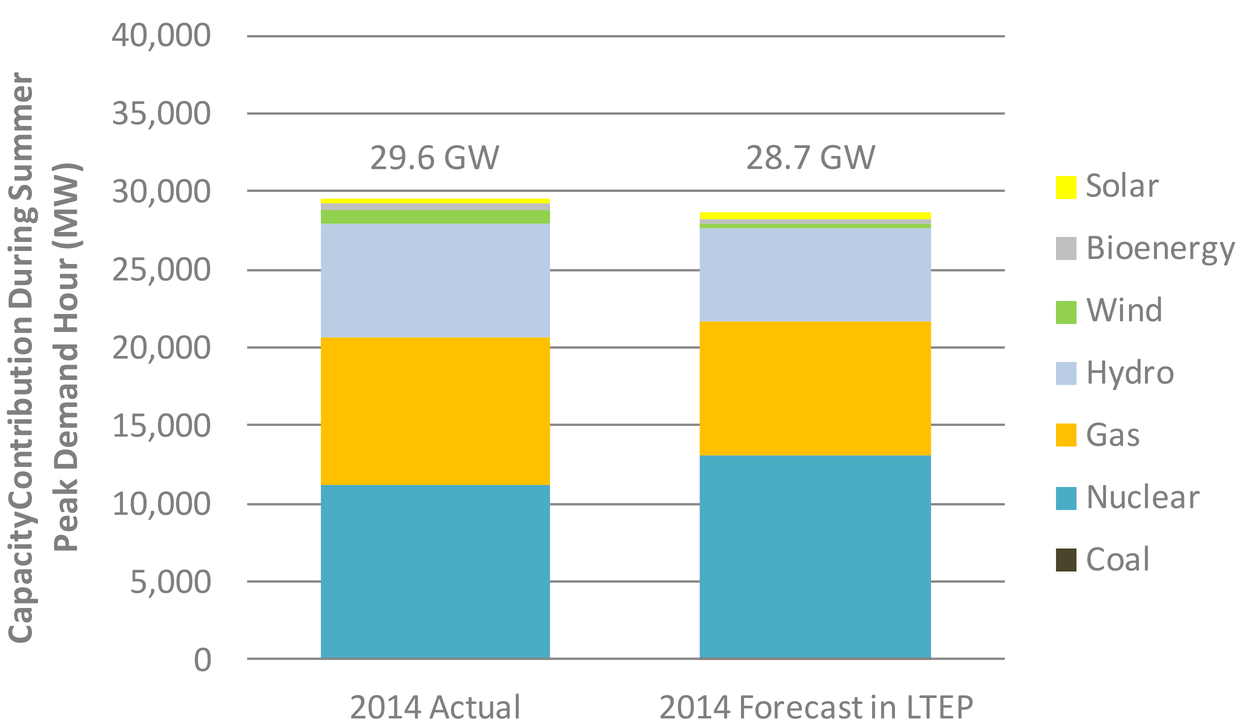
Results:

- 2014 actual installed capacity is lower than forecast by about 0.4 GW (-1%)
- Ontario's 2014 installed capacity consisted of about 34% nuclear, 26% natural gas and 38% renewable resources
- Deviations between actual and forecasted values is primarily due to construction delays with non-hydro renewables

Notes:

- Installed capacity consists of grid and distribution-connected generation.
- The 2014 forecast is based on data from Figure 16 in the 2013 LTEP.
- The 2014 actual is based on existing grid-connected generation as of February 13, 2015, as per the March 2015 IESO 18-Month Outlook report and existing distribution-connected generation as of December 2014. Coal was removed from the Ontario supply as of April 2014.
- Demand response capacity consists of DR programs and dispatchable customer loads under contract in the market.

Capacity available at summer peak hour



Results:

- Capacity available during peak demand accounts for outages and seasonal variations in output
- Two nuclear units were unavailable during the actual hour of peak demand in 2014, and one was significantly de-rated, as compared to that assumed in the 2013 LTEP
- Hydro and wind availability in the actual hour of peak demand during summer 2014 was higher compared to the 2013 LTEP
- In 2014, the system peak did not occur in the summer

Note:

- The 2014 forecast is based on data from the 2013 LTEP.
- The 2014 actual is based on grid-connected generation that was logged as providing capacity to the IESO-controlled grid during the peak demand hour on August 26, 2014, and distribution-connected generation is based on settlement data from local distribution companies
- Coal removed from the Ontario supply as of April 2014.

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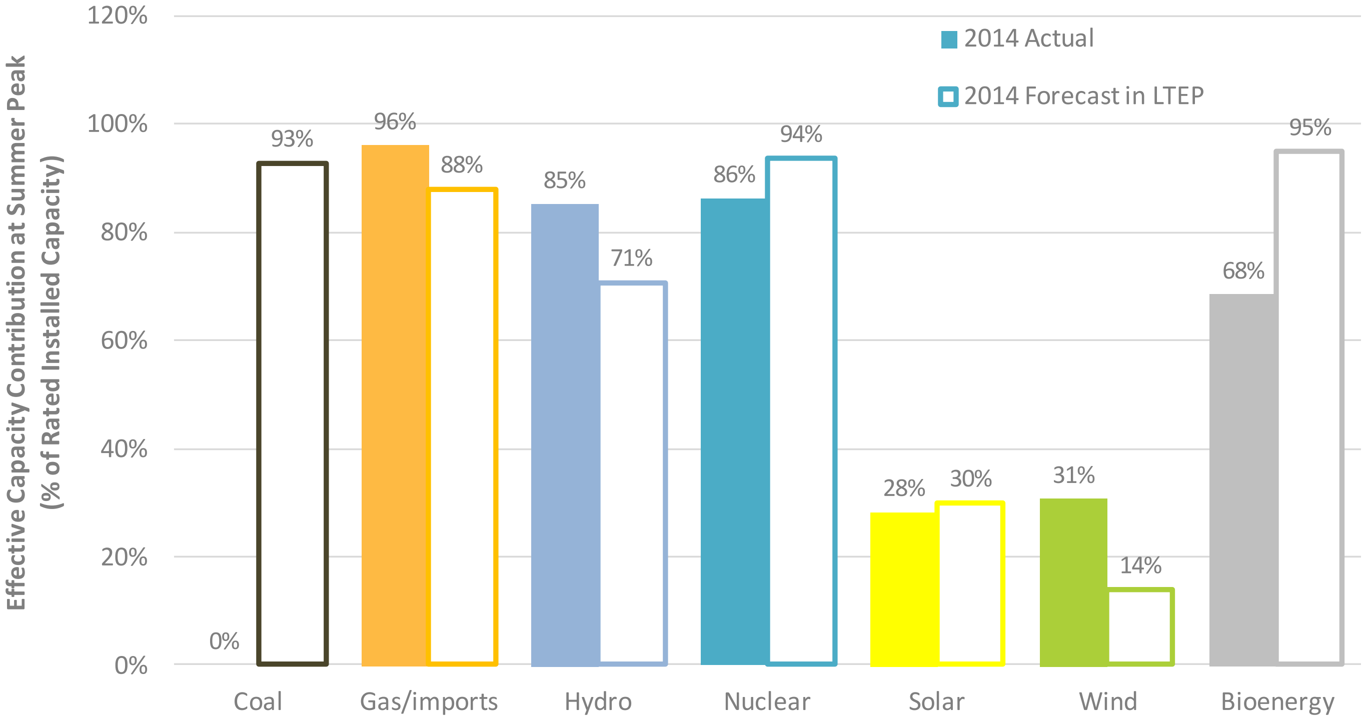
Capacity contribution, as a percentage of installed capacity, at summer peak hour



Results:

- Not all capacity is available equally at peak. A capacity contribution is the measure of how much a resource can be relied upon to deliver relative to its installed capacity
- Actual nuclear availability was lower in 2014 due to unit outages
- Actual bioenergy availability was lower in 2014 during the actual hour of peak summer demand, as some facilities were not operating at that time
- Wind and hydro output during hour of peak summer demand was higher as compared to that assumed in the 2013 LTEP

Note:

- The 2014 forecast is based on data from the 2013 LTEP.
- The 2014 actual is based on grid-connected generation that was logged as providing capacity to the IESO-controlled grid during the peak demand hour on August 26 2014, and distribution-connected generation is based on settlement data from local distribution companies
- Coal removed from the Ontario supply as of April 2014.

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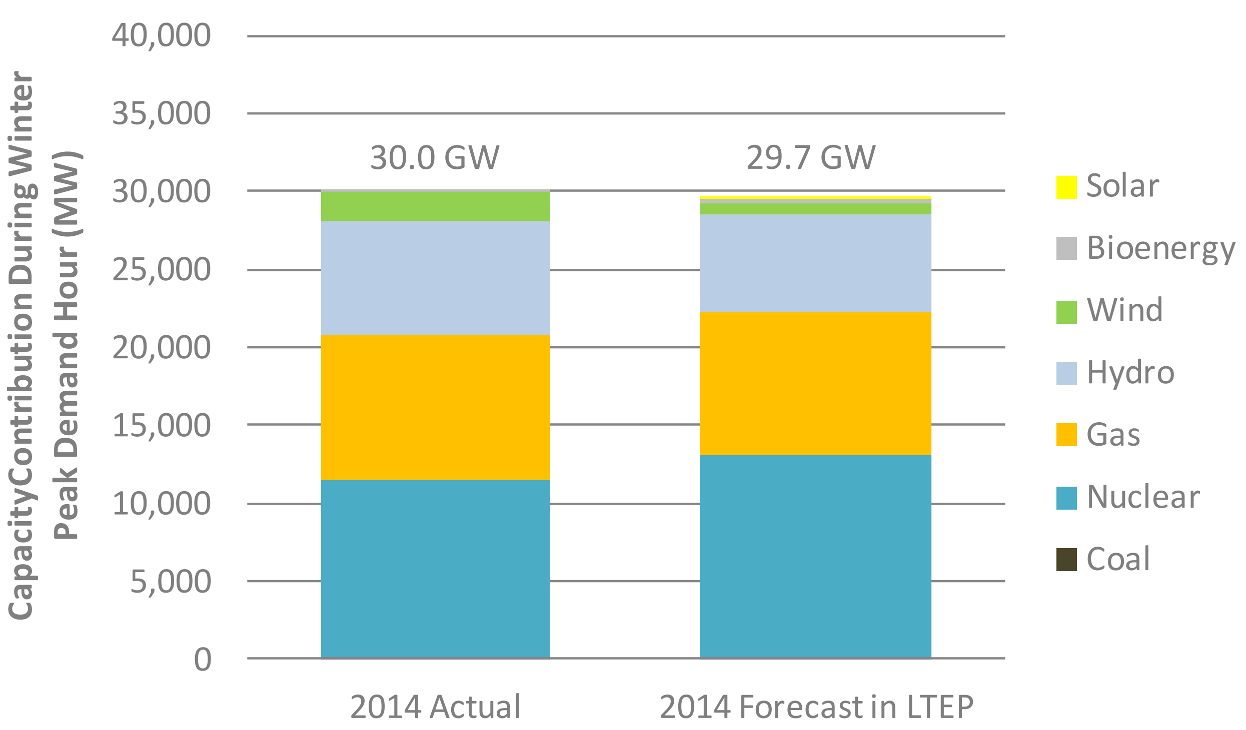
Capacity available at winter peak hour



Results:

- In 2014, the system peak occurred on January 7, 2014
- Capacity available during peak demand accounts for outages and seasonal variations in output
- Two nuclear units were unavailable during the actual hour of winter peak demand during 2014, compared to that assumed in the 2013 LTEP
- Hydro and wind availability in the actual hour of peak demand during winter 2014 was higher compared to that assumed in the 2013 LTEP

Note:

- The 2014 forecast is based on data from the 2013 LTEP.
- The 2014 actual is based on grid-connected generation that was logged as providing capacity to the IESO-controlled grid during the peak demand hour on January 7, 2014. Embedded generation is assumed to be negligible, as the peak demand hour occurred after sunset (thus solar output would be zero), and most wind generators are grid-connected
- Coal removed from the Ontario supply as of April 2014.

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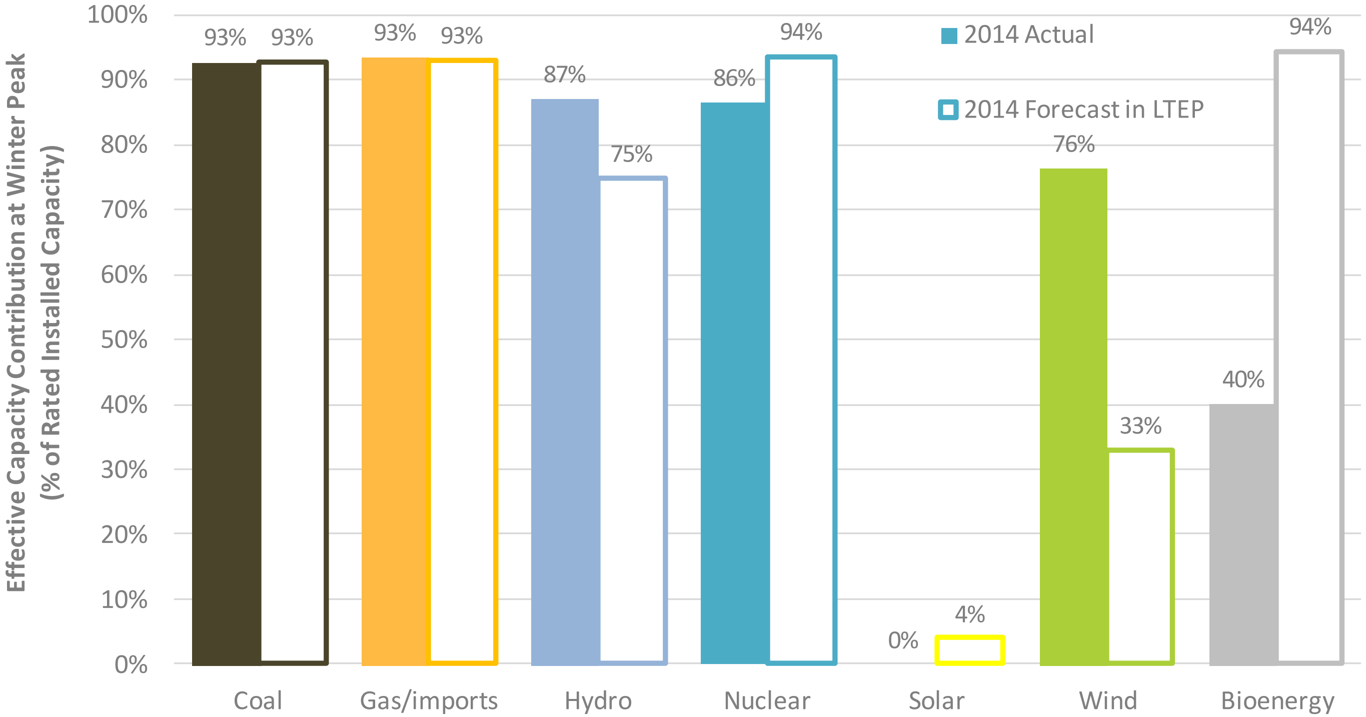
Capacity contribution, as a percentage of installed capacity, at winter peak hour



Results:

- Not all capacity is available equally at peak. A capacity contribution is the measure of how much a resource can be relied upon to deliver relative to its installed capacity.
- Wind and hydro output during hour of actual winter peak demand was higher compared to that assumed in the 2013 LTEP
- Actual bioenergy availability was lower in 2014 during the actual hour of peak winter demand, as some facilities were not operating at that time

Note:

- The 2014 forecast is based on the data from the 2013 LTEP.
- The 2014 actual is based on grid-connected generation that was logged as providing capacity to the IESO-controlled grid during the peak demand hour on January 7 2014. Embedded generation is assumed to be negligible, as peak demand hour occurred after sunset (thus solar output would be zero), and most wind generators are grid-connected
- Coal removed from the Ontario supply as of April 2014.

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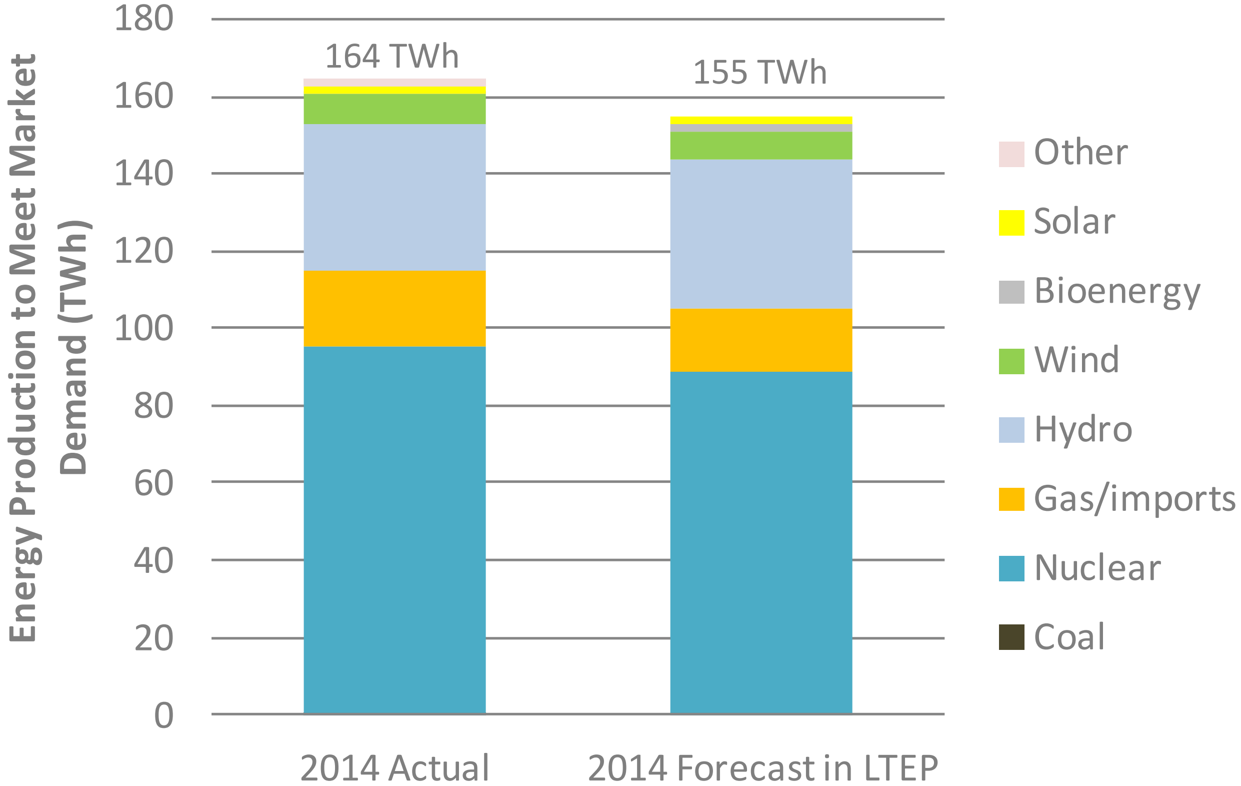
Energy production



Results:

- 2014 actual energy production is higher than forecast because of greater market demand, by 9 TWh (5.8%)
- Ontario's 2014 energy production is largely supplied by nuclear generation, followed by hydroelectric and gas/imports
- Of the 2014 actual energy production, 19 TWh was exported, compared to 13.7 TWh forecasted in the 2013 LTEP for exports.
- The 2013 LTEP projected 3.1 TWh of imports; actual imports in 2014 were 4.9 TWh

Notes:

- Energy production consists of grid- and distribution-connected generation to meet market demand (includes exports).
- The 2014 forecast is based on Figure 15 in LTEP, with the inclusion of imports.
- 2014 actual is based on IESO data, with the inclusion of imports.
- "Other" includes injections from load or other fuels not identified.
- Coal was removed from the Ontario supply as of April 2014.

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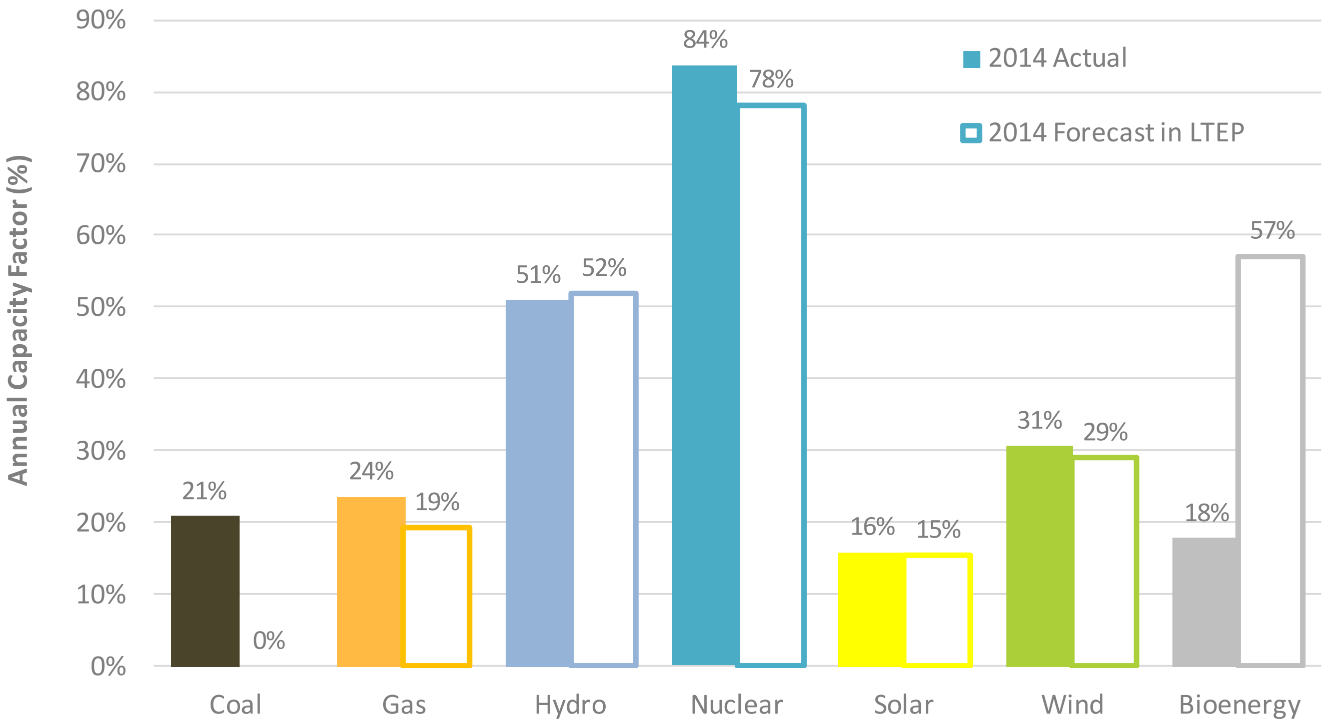
Annual energy capacity factor, by fuel type



Results:

- Actual production from bioenergy resources in 2014 was considerably lower than that predicted in the 2013 LTEP; production from nuclear, solar, wind, and natural gas was higher than forecasted.
- Energy from coal was higher than projected because remaining stockpiles of fuel were used up before shutdown.

Notes:

- Capacity factor is calculated as the total energy production from a given resource in 2014 as a fraction of its installed capacity, assuming it operated for all hours of that it was installed in 2014. As the swing resources, coal and gas capacity factors will reflect when they operate to meet the changing demand and will tend to be lower than their maximum capability, while for all other resources the capacity factor tends to reflect their maximum capability to produce energy in the period.
- Coal was removed from the Ontario supply as of April 2014.

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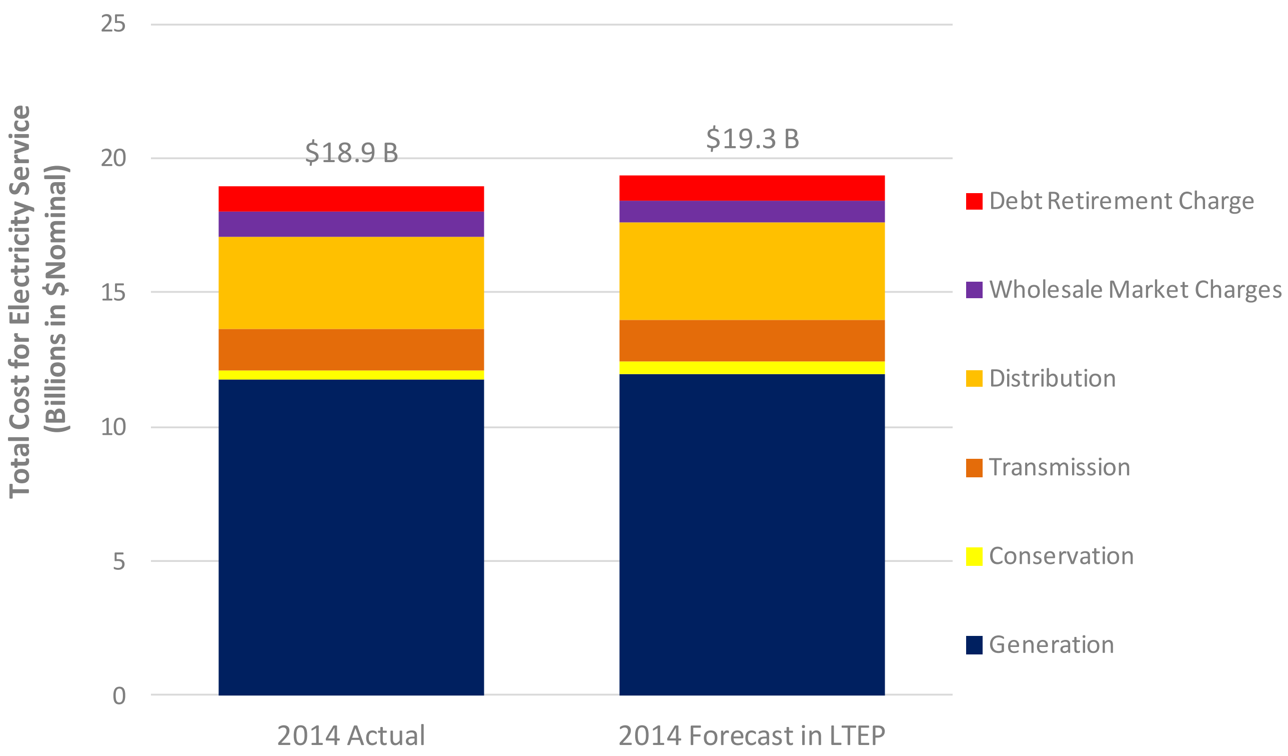
Total cost of electricity service



Results:

- The 2014 total cost of electricity service is lower by $0.4 billion (-2%) than forecast
- Conservation, distribution and generation costs are lower than 2013 LTEP by 27% ($0.13B), 6% ($0.22B), and 2% ($0.2B), respectively.
- These lower costs were slightly offset by higher transmission, wholesale market charges and debt retirement charges

Notes:

- The 2013 LTEP reported the total cost of electricity services in real $2012.
- To convert the 2013 LTEP real $2012 to nominal dollars the actual 2012 Ontario CPI index factor of 1.034 was used.

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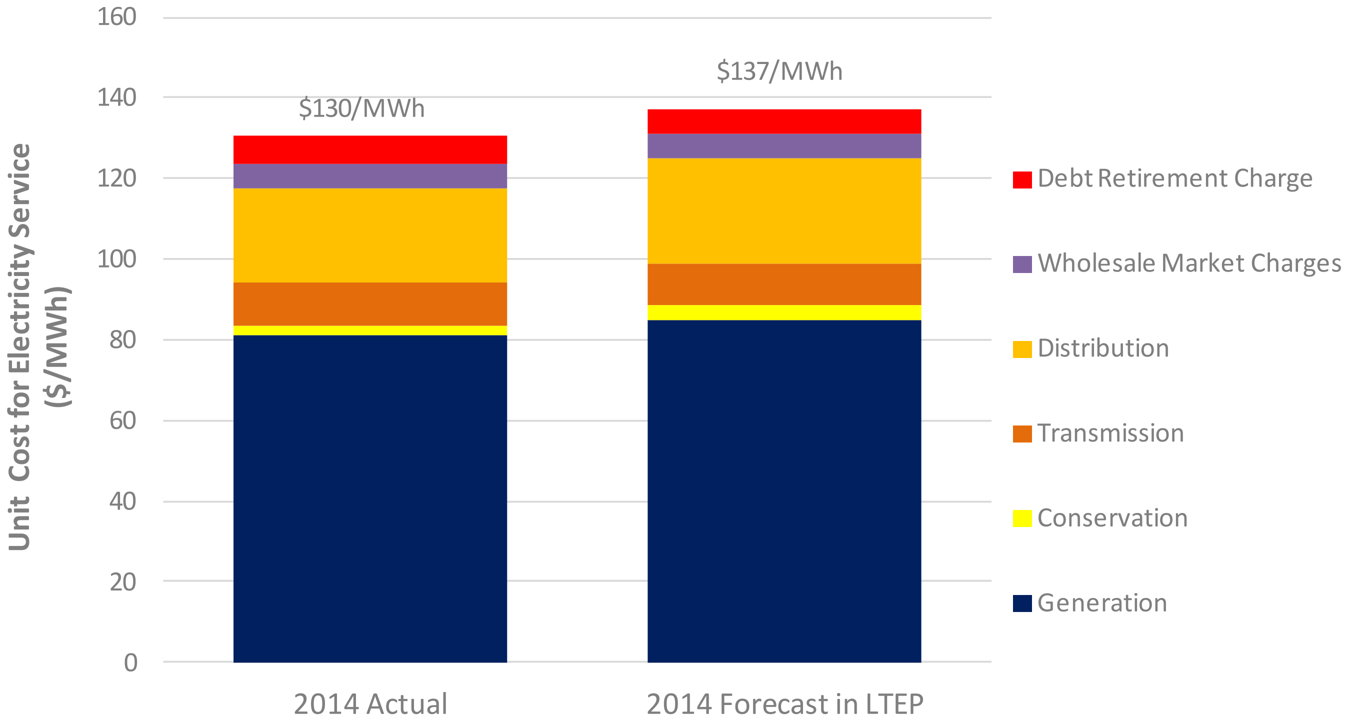
Unit cost of electricity service



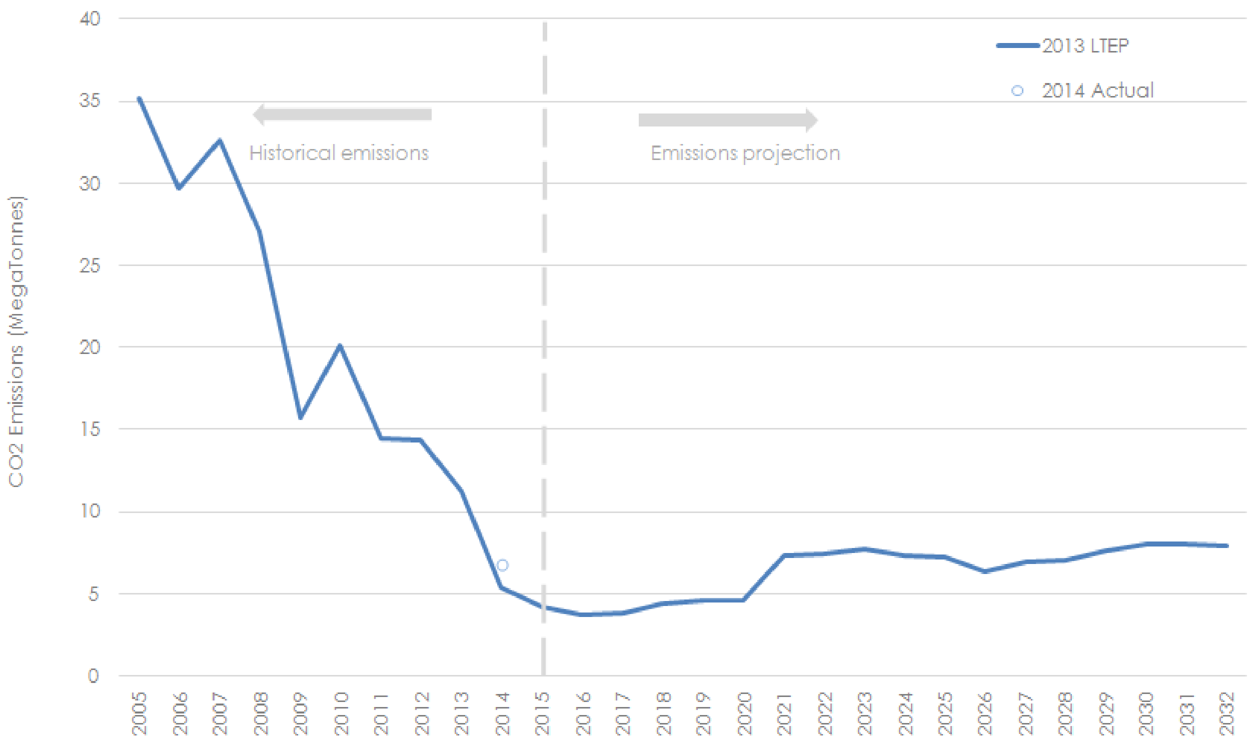
Results:

- The 2014 actual unit cost is lower than the forecast by about 5% (-$7/MWh)
- The higher percentage change for the unit rate comparison versus the percentage change for total cost is attributed to the higher actual demand in 2014 of 145 TWh, which is 4 TWh higher than the LTEP forecast of 141 TWh
- The 2014 actual demand load was higher due to the polar vortex in the winter of 2013/2014.

Notes:

- Unit cost for electricity is the total cost divided by domestic demand.
- 2014 actual unit cost is based on the 2014 actual demand of 145 TWh .
- 2013 LTEP unit cost is based on the 2013 LTEP forecast of 141 TWh.

Greenhouse gas emissions



Results:

- 2014 preliminary actual CO_2 emissions (6.8 MT) are approximately 1.4 MT greater than forecast (5.4 MT)
- This difference is attributable to higher demand and greater coal and gas production:
- 1.4 MT difference attributed to:
    - Coal: 79 GWh → 0.1 MT
    - Gas: 13,885 GWh → 1.3 MT

Notes:

- The 2014 preliminary actual CO_2 emissions value is estimated from actual energy production and facility emission factors using reported data to Environment Canada Greenhouse Gas Reporting Program. Actual 2014 CO_2 emissions for the electricity sector will not be available until April/May 2016.
- The historical CO_2 data (2005-2013) has been updated to reflect the 2015 National Inventory Report, which often recalculates historical emissions.

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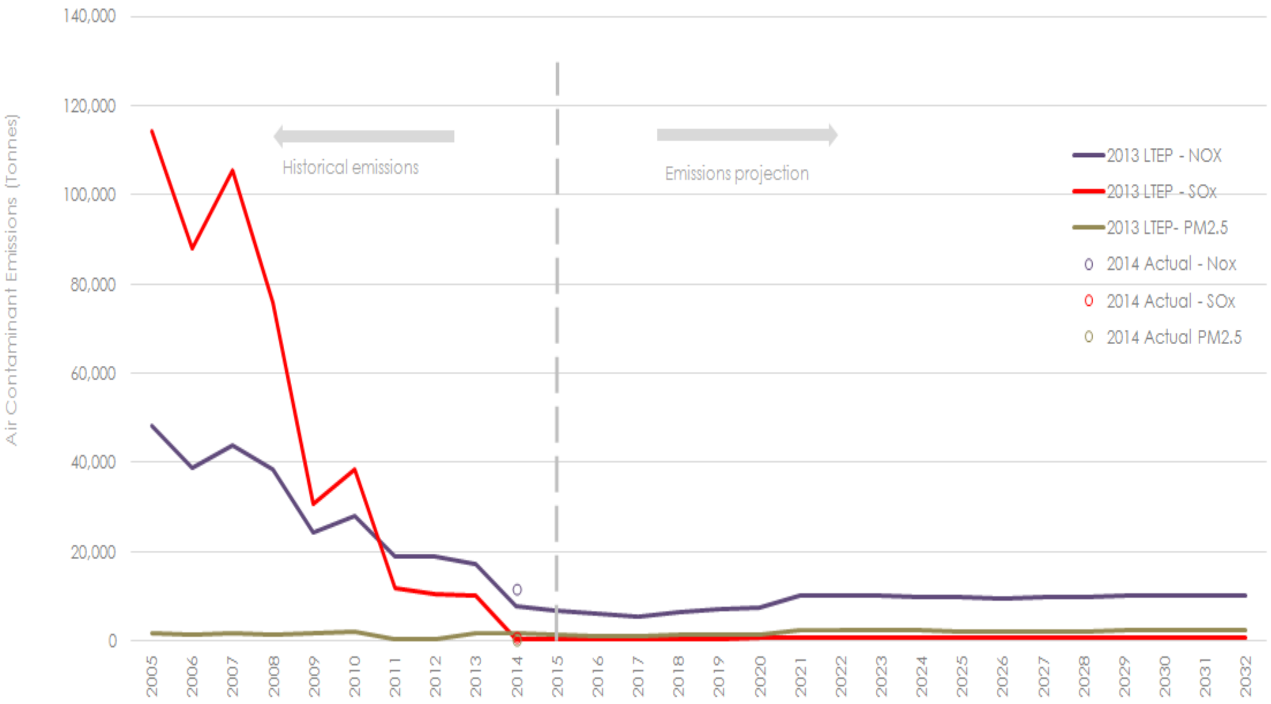
Nitrogen oxides, sulphur oxides and particulate matter emissions



Results:

- 2014 actual NOx and SOx emissions are higher than forecast; $PM_{2.5}$ emissions are lower than forecast (see appendix for additional data)
- The difference in NOx and SOx is attributable to higher demand and greater coal and gas production compared to forecast.
- The large variance between forecast and actual $PM_{2.5}$ emissions is the result of a high average-based emission factor assigned to the gas fleet in the 2013 LTEP. For future forecasts, emission factors will be applied on a facility-by-facility basis using NPRI data, to reflect the wide range of facility-specific operating conditions that influence emissions.

Notes:

- The historical 2005 to 2013 actuals are as reported to the Environment Canada National Pollutant Release Inventory (NPRI).
- 2014 actuals are also taken from the NPRI; however, they are preliminary in that they are in the process of being verified.

Appendices

Appendix: Energy and peak demand

Energy (TWh)	**Actual**		**2013 LTEP**
	Ontario demand (Non weather-corrected + embedded generation)	Ontario demand (Weather-corrected + embedded generation)	Demand net of conservation (Weather normal)
2013	145.0	144.7	142.8
2014	145.0	144.5	140.8

Peak (MW)	**Actual**		**2013 LTEP**
	Ontario demand (Non weather-corrected + embedded generation)	Ontario demand (Weather-corrected + embedded generation)	Demand net of conservation (Weather normal)
2013	25,414	24,743	23,724
2014	23,385	22,730	23,503

Notes:

- The 2013 LTEP energy demand and peak demand are weather normal and net of conservation and peak demand savings.
- The actual and forecasted energy demand and peak demand include impacts of distributed generation.

Appendix: Conservation energy savings

Conservation Savings (TWh)	2006	2007	2008	2009	2010	2011	2012	2013	2014 Actual	2014 Forecast in 2013 LTEP
Program Savings (including persistence)	1.6	3.4	3.9	4.6	5.0	5.7	6.3	7.1	8.1	8.3
Codes and Standards Savings	0.0	0.1	0.2	0.3	0.5	1.0	1.6	1.8	1.8	1.8
Total Energy Savings	**1.6**	**3.5**	**4.0**	**4.9**	**5.4**	**6.7**	**7.9**	**8.9**	**9.9**	**10.1**

Notes:

- Savings are at the generator level, and include transmission and distribution losses
- Savings from conservation programs are between 2006 and 2014 including persistence. Savings from codes and standards are between 2006 and 2013 and assume the same as forecast in LTEP. Forecast new 2014 savings from codes and standards are not included. Evaluation of savings from codes and standards is under way.

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Appendix: Demand management

Peak Reduction of Demand Response Resources (MW)	2014 Actual	2014 Forecast in 2013 LTEP
Dispatchable Load	0	377
Industrial Conservation Initiative (ICI)	975	300
Time-of-Use Rate	59	184
IESO DR Programs (DR2, DR3 and peaksaver PLUS)	555	539
Total	**1,589**	**1,399**

Notes:

- The IESO DR programs (DR2, DR3 and *peaksaver*PLUS) reported a total demand saving of 555 MW, which is ex ante load impact.
- Time-of-use peak reduction is from the IESO's evaluation.
- ICI impact is the IESO's estimate on peak days of 2014.

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Appendix: Installed capacity

	2014 Actual		2014 Forecast in 2013 LTEP	
	Installed Capacity (MW)	**%**	**Installed Capacity (MW)**	**%**
Nuclear	12,947	34%	12,946	34%
Coal	-	0%	153	0%
Gas	10,065	26%	9,786	26%
Hydro	8,712	23%	8,421	22%
Wind	3,498	9%	3,770	10%
Bioenergy	606	2%	532	1%
Solar	1,549	4%	1,887	5%
Demand Response	627	2%	655	2%
Total	**38,005**	**100%**	**38,374**	**100%**

Notes:

- Installed capacity consists of grid- and distribution-connected generation.
- The 2014 forecast is based on data from Figure 16 in the 2013 LTEP.
- The 2014 actual is based on existing grid-connected generation as of February 13, 2015, as per the March 2015 IESO 18-Month Outlook report and existing distribution-connected generation as of December 2014. Coal was removed from the Ontario supply as of April 2014.
- Demand response capacity consists of DR programs and dispatchable customer loads under contract in the market.

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Appendix: Capacity at summer peak hour

	2014 Actual		2014 Forecast in 2013 LTEP	
	Available Capacity (MW)	Capacity Contribution (% of Installed)	Available Capacity (MW)	Capacity Contribution (% of Installed)
Nuclear	11,212	86%	12,894	94%
Coal	-	0%	153	93%
Gas	9,488	96%	8,604	88%
Hydro	7,258	85%	5,948	71%
Wind	942	31%	415	14%
Bioenergy	301	68%	288	95%
Solar	383	28%	380	30%
Total	**29,584**	**-**	**28,682**	**-**

Notes:

- The 2014 forecast is based on data from the 2013 LTEP.
- The 2014 actual is based on grid-connected generation that was logged as providing capacity to the IESO-controlled grid during the peak summer demand hour on August 26 2014, and distribution-connected generation is based on settlement data from local distribution companies
- Coal was removed from the Ontario supply as of April 2014.

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Appendix: Capacity at winter peak hour

	2014 Actual		2014 Forecast in 2013 LTEP	
	Available Capacity (MW)	Capacity Contribution (% of Installed)	Available Capacity (MW)	Capacity Contribution (% of Installed)
Nuclear	11,256	86%	12,894	94%
Coal	153	93%	153	93%
Gas	9,330	93%	9,215	93%
Hydro	7,291	87%	6,275	75%
Wind	1,903	76%	802	33%
Bioenergy	46	40%	287	94%
Solar	-	0%	44	4%
Total	**29,979**	**-**	**29,670**	**-**

Notes:

- The 2014 forecast is based on data from the 2013 LTEP.
- The 2014 actual is based on grid-connected generation that was logged as providing capacity to the IESO-controlled grid during the peak demand hour on January 7, 2014. Embedded generation is assumed to be negligible, as peak demand hour occurred after sunset (thus solar output would be zero), and most wind generators are grid-connected
- Coal removed from the Ontario supply as of April 2014.

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Appendix: Energy production

	2014 Actual		2014 Forecast in 2013 LTEP	
	Energy Production (TWh)	**%**	**Energy Production (TWh)**	**%**
Nuclear	94.9	58%	88.6	57%
Coal	0.1	0%	0.0	0%
Gas/imports	19.9	12%	16.6	11%
Hydro	37.9	23%	38.2	25%
Wind	7.8	5%	7.4	5%
Bioenergy	0.5	0%	2.0	1%
Solar	1.8	1%	1.8	1%
Other	1.6	1%	--	--
Total	**164.3**	**100%**	**154.6**	**100%**

Notes:

- Energy production consists of grid- and distribution-connected generation to meet market demand (includes exports).
- The 2014 forecast is based on Figure 15 in LTEP, with the inclusion of imports.
- 2014 actual is based on IESO data, with the inclusion of imports.
- "Other" includes injections from load or other fuels not identified.
- Coal was removed from the Ontario supply as of April 2014.

Appendix: Annual energy capacity factor

	Annual Energy Capacity Factor	
	2014 Actual	2014 Forecast in 2013 LTEP
Nuclear	84%	78%
Coal	21%	0%
Gas	24%	19%
Hydro	51%	52%
Wind	31%	29%
Bioenergy	18%	57%
Solar	16%	15%

Notes:

- Capacity factor is calculated as the total energy production from a given resource in 2014 as a fraction of its installed capacity, assuming it operated for all hours that it was installed in 2014. As the swing resources, coal and gas capacity factors will reflect when they operate to meet the changing demand and will tend to be lower than their maximum capability, while for all other resources the capacity factor tends to reflect their maximum capability to produce energy in the period.
- Coal was removed from the Ontario supply as of April 2014.

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Appendix: Total cost of electricity service

	Total Cost of Electricity Service for Ontario $Billions (nominal)	
	2014 Actual	**2014 Forecast in 2013 LTEP**
Generation	11.8	12.0
Conservation	0.3	0.5
Transmission	1.6	1.5
Distribution	3.4	3.6
Wholesale	0.9	0.8
Debt Retirement Charge	1.0	0.9
Total Costs	**18.9**	**19.3**

Notes:
- The 2013 LTEP reported the total cost for electricity services in real $2012.
- To convert the 2013 LTEP real $2012 to nominal dollars the actual 2012 Ontario CPI index factor of 1.034 was used.

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Appendix: Average unit cost of electricity service

	Unit Cost of Electricity Service $/MWh (nominal)	
	2014 Actual	**2014 Forecast in 2013 LTEP**
Generation	81	85
Conservation	2	3
Transmission	11	11
Distribution	24	26
Wholesale	6	6
Debt Retirement Charge	7	6
Unit Costs ($/MWh)	**130**	**137**
Domestic Demand (TWh)	**145**	**141**

Notes:

- Unit cost of electricity is the total cost divided by domestic demand.
- 2014 actual unit cost is based on the 2014 actual demand of 145 TWh.
- 2013 LTEP unit cost is based on the 2013 LTEP forecast of 141 TWh.

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Appendix: Greenhouse gas emissions

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
CO2 Emissions (MT) (2013 LTEP)	35.20	29.70	32.60	27.10	15.70	20.10	14.50	14.40	11.20	5.41	4.25	3.72	3.77	4.42
CO2 Emissions (MT) (2014 Preliminary Actual)	-	-	-	-	-	-	-	-	-	6.76	-	-	-	-
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CO2 Emissions (MT) (2013 LTEP)	4.63	4.61	7.32	7.41	7.71	7.36	7.19	6.32	6.94	7.02	7.63	7.98	8.05	7.96
CO2 Emissions (MT) (2014 Preliminary Actual)	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Notes:

- The 2014 preliminary actual CO_2 emissions value is estimated from actual energy production and facility emission factors using reported data to Environment Canada Greenhouse Gas Reporting Program. Actual 2014 CO_2 emissions for the electricity sector will not be available until April/May 2016.
- The historical CO_2 data (2005-2013) has been updated to reflect the 2015 National Inventory Report, which often recalculates historical emissions.

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Appendix: Nitrogen oxides, sulphur oxides and particulate matter emissions

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
NOx Emissions (T) (2013 LTEP)	48,143	38,955	43,846	38,314	24,389	28,130	18,988	19,077	17,183	7,685	6,830	6,146	5,587	6,312
NOx Emissions (T) (2014 Actual)	-	-	-	-	-	-	-	-	-	11,520	-	-	-	-
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
NOx Emissions (T) (2013 LTEP)	7,107	7,532	10,324	10,072	10,118	9,984	9,855	9,505	9,710	9,872	10,019	10,206	10,078	10,028
NOx Emissions (T) (2014 Actual)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
SOx Emissions (T) (2013 LTEP)	114,323	87,932	105,420	76,020	30,768	38,448	11,971	10,342	10,192	439	407	384	403	472
SOx Emissions (T) (201 Actual)	-	-	-	-	-	-	-	-	-	847	-	-	-	-
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
SOx Emissions (T) (2013 LTEP)	532	572	791	795	799	791	785	764	779	784	797	803	794	781
SOx Emissions (T) (2014 Actual)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
PM2.5 Emissions (T) (2013 LTEP)	1,787	1,529	1,876	1,314	1,779	2,120	562	478	439	1,613	1,330	1,193	1,205	1,413
PM2.5 Emissions (T) (2014 Actual)	-	-	-	-	-	-	-	-	-	281	-	-	-	-
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
PM2.5 Emissions (T) (2013 LTEP)	1,508	1,538	2,288	2,285	2,356	2,257	2,220	2,024	2,172	2,183	2,359	2,400	2,422	2,376
PM2.5 Emissions (T) (2014 Actual)	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Notes:
- The historical 2005 to 2013 actuals are as reported to the Environment Canada National Pollutant Release Inventory (NPRI).
- 2014 actuals are also taken from the NPRI; however ,they are preliminary in that they are in the process of being verified.

UNDERTAKING – J12.7

Undertaking

To make best efforts to provide the source for the forecast for the industrial sector.

Response

The industrial price forecast Hydro One used as an input to the information provided in Exhibit E2, Tab 2, Schedule 1 (and referenced on page 27 of Exhibit K12.6) is collected from the National Energy Board energy outlook. The latest version of it is available at the following website:

https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html

The 2015 version of this outlook was used as an input in Hydro One's forecast.

Witness: Bijan Alagheband

UNDERTAKING – J12.8

Undertaking

To provide a description of the derivation of energy prices, including the base and its alteration to calculate the prices.

Response

The derivation of total prices shown on page 9 of Exhibit E2-02-01 ("Total Prices") is described below. For clarity, Total Prices include other charges such as delivery, regulatory, and debt retirement charges.

First, the simple average of regulated two-tiered electricity prices, which are available on the OEB's website, was calculated to arrive at a single measure of electricity commodity price for each year.

Next, for each of the residential, commercial and industrial sectors, the historical relationship between the commodity price noted above and Total Prices prior to 2012 was used to calculate the Total Prices for the years 2012-2015.

Finally, for each of the sectors noted above, the Total Prices were deflated using the consumer price index to express all figures in constant dollars. The growth rate of the Total Prices (now expressed in constant dollars) was applied to the 2011 Total Prices used in the forecast models to calculate the Total Prices for the years 2012-2015.

UNDERTAKING – J12.9 A

Undertaking

Compare the actual electricity prices that you evolved here with the forecast prices in the 2013 long-term energy plan.

Response

The table below provides a comparison of the electricity prices forecast in the LTEP 2013 with the electricity prices used for econometric modelling purposes and implicitly embedded in the tables provided at Exhibit 2, Tab 2, Schedule 1.

Comparison of Actual with LTEP 2013 Forecast Prices
(cents/kWh)

Sector	LTEP 2013	Actual
Residential		
2012	15.0	15.0
2013	16.2	16.2
2014	17.6	18.0
2015	19.0	19.5
Commercial		
2012	12.8	12.8
2013	14.1	14.1
2014	15.4	15.4
2015	15.6	16.4
Industrial		
2012	8.6	7.6
2013	9.7	8.6
2014	11.0	9.5
2015	11.1	10.2

Witness: Bijan Alagheband

UNDERTAKING – J12.9 B

Undertaking

To provide two forecasts showing actual load forecast numbers based on a 20-year trend

Response

A 20-YEAR TREND

Two sets of charge determinants forecasts based on 20-year trend approach are presented below.

Table 1 below shows the charge determinants that correspond to the 20 year tend impacts previously provided in the interrogatory response at Exhibit I, Tab 4, Schedule 42 part b). In this approach, the difference between the normal temperature under 20-year trend and 31-year average is used to calculate the amount by which the forecast would change. The resulting charge determinants presented in Table 1 are marginally higher than the forecast proposed in the current application at page 1 of Exhibit E1, Tab 3, Schedule 1.

Table 1

Forecast Based on 20-Year Trend of Normal Temperature Using Approach 1
(12-Month Average Peak in MW)

Year	Ontario Demand	Network Connection	Line Connection	Transformation Connection
2017	20,379	20,411	19,747	16,877
2018	20,392	20,424	19,760	16,888

Table 2 shows the charge determinants that correspond to a 20-year trend approach where the same models described in Exhibit E1, Tab 3, Schedule 1 are utilized to produce a forecast based on a 20-year trend of normal values (rather than 31-year average values) for temperature variables in the models over the forecast period. The resulting charge determinants presented in Table 2 are marginally lower compared to the forecast proposed in the current application at page 20 of Exhibit E1, Tab 3, Schedule 1.

Table 2

Forecast Based on 20-Year Trend of Normal Temperature Using Approach 2
(12-Month Average Peak in MW)

Year	Ontario Demand	Network Connection	Line Connection	Transformation Connection
2017	20,371	20,403	19,739	16,870
2018	20,375	20,407	19,743	16,873

The first approach discussed above assumes that the models and resulting forecast submitted for the current application do not reflect possible the load impact of climate change. This is not correct given that any material change in load trend (e.g. 20 year) due to possible climate change **does** affect estimated coefficients of the models used in the current application and, thereby, the models' forecast.

It should be noted that, as detailed on pages 10 to 14 in Exhibit E1, Tab 3, Schedule 1, the majority of utilities use 30-year (or longer) average temperature for weather normalization. In addition to Hydro One, this same weather-normalization approach is used by the IESO and weather organizations such as Environment Canada and National Oceanic and Atmospheric Administration in US. Accordingly, Hydro One does not recommend using 20-year trending of normal values for forecasting purposes.