Policies to Incent Load Growth to Reduce Electricity Costs for Existing Ontario Customers

Prepared for:

Ontario Energy Association

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Submitted by:

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EXECUTIVE SUMMARY

Given the structure of Ontario's electricity system, reductions in electricity load lead to rate increases for electricity ratepayers, as system fixed costs are spread over fewer kilowatt hours. Between 2005 and 2009, Ontario saw a significant reduction in load as a result of a decline in Ontario's manufacturing base. This reduction in load resulted in rate increases for remaining ratepayers, particularly given system capacity was increasing at the same time.

As a result of COVID-19 pandemic, Ontario is once again facing a situation where load has declined significantly, and as a result electricity rates will have to increase (as will costs for taxpayers who subsidize above-inflation rate increases for residents and small businesses). It is clear that all existing ratepayers have an economic interest in policies that promote load growth to either help reduce rates or offset pressure for rate increases. This is an opportune time for Ontario to examine its electricity policies related to load growth to determine whether Ontario has the tools it needs to optimize load growth for the benefit of existing ratepayers.

To help alleviate cost pressures facing Ontario's electricity customers, the province should consider programs or policies that increase demand. In doing so, the per unit cost of each unit of electricity for all customers can be reduced and the need for taxpayer-backed subsidies can be lessened. Our analysis shows that a 5 TWh increase in overall demand could have reduced the per unit cost for all customers by 3% in 2019. Similar per unit reductions would occur in future years until large generation capacity retirements begin to take place in the mid- to late-2020s.

This study found that all of Ontario's neighbouring jurisdictions have programs in place to incent load growth. They do this by providing low cost electricity to new or existing customers for economic development or they provide rate relief for customers that add demand to the power system. Ontario does not have a comparable competitive offering at this time, putting us at a disadvantage in trying to grow Ontario's economy and electricity load to reduce rates for existing customers.

Based on the foregoing, this paper recommends that Ontario introduce a program that provides a duration-limited (e.g. 1-3 years) rate incentive for customers that create either new demand through investments in new facilities in Ontario or increase current levels of electricity consumption through investments in existing facilities.

These recommendations would make Ontario more attractive in the locational decision-making process when making capital investments.

Recommendations:

1. **A reduced demand charge for customers that provides either new demand in Ontario or increase current levels of electricity consumption;**
2. **Low-cost allocations of energy that better utilize the province's surplus generation.**

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1. INTRODUCTION

Power Advisory LLC (Power Advisory) was retained by the Ontario Energy Association (OEA) to study the impact of load (i.e., electricity demand) growth on commercial and industrial electricity rates in Ontario. We were asked to, specifically:

1. Analyze the impact of demand on commercial and industrial electricity rates;
2. Undertake a jurisdictional survey to identify programs in these other jurisdictions that provide incentives to grow commercial and industrial demand;
3. Determine if there are programs that Ontario could modify or adopt in order to increase demand and reduce industrial and commercial rates.

1.1 Overview of this Report

This report is organized into four chapters, starting with this introduction. The second chapter provides a breakdown of costs charged to electricity customers, a review of electricity price increases over the past decade, and an overview of the underlying drivers for this price increase. Notably, this chapter includes an analysis on the impact that falling demand over the past decade had on electricity prices. The third chapter provides a jurisdictional review of programs in neighbouring jurisdictions that promote demand growth. The final chapter provides a number of recommendations that could be implemented in Ontario that would promote demand growth and lower electricity bills for all customers.

2. ELECTRICITY PRICE INCREASES AND DEMAND REDUCTION IN ONTARIO

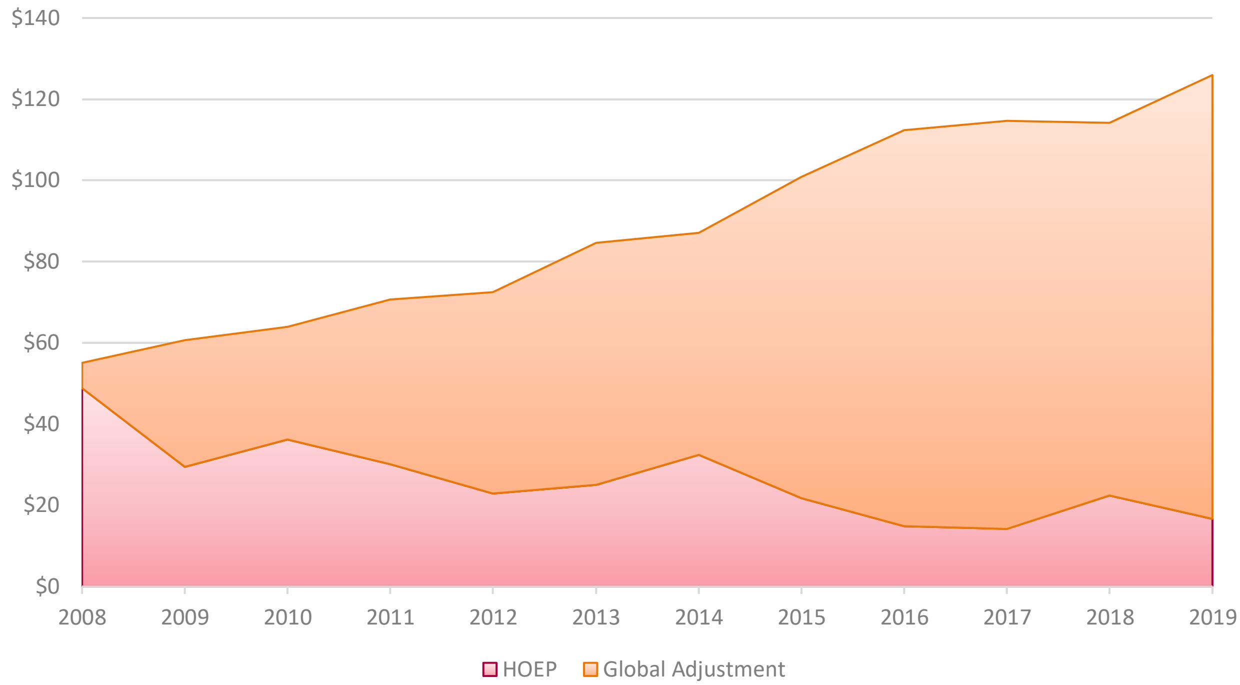
2.1 A Decade of Electricity Price Increases in Ontario

The combination of falling demand in Ontario and an increase in long-term fixed costs has resulted in a double-digit increase in electricity prices over the last decade (described in more detail in Appendix B). The provincial government has introduced a number of policies over that time in an attempt to mitigate the economic impact of price increases (discussed below).

The increase in electricity prices for small volume customers – small businesses and households – can be seen most clearly in the rates set every six months by the Ontario Energy Board (OEB) through its Regulated Price Plan (RPP). The RPP sets default supply rates for the following year based on a forecasted cost of energy, both in the province's wholesale energy market and its contracted procurement and conservation programs along with Ontario Power Generation's (OPG's) regulated revenues. The price charged to customers is then set for off-peak, mid-peak, and on-peak hours. Over the last decade, the regulated rate set by the OEB has increased (in nominal dollars) 130%, 80%, and 124% for off-peak, mid-peak and peak rates, respectively, between 2009 and 2019. Inflation over that time period in Ontario was slightly more than 20%. The province has introduced a number of policies to mitigate the impact of that price increase, including the Fair Hydro Plan in 2017 and, more recently, the suspension of Time-of-Use (TOU) rates during the COVID-19 pandemic, among other policies. The current Ontario Electricity Rebate program reduces bills for small-volume customers by as much as 31.8%.

Large industrial and commercial customers typically pay the prevailing wholesale price of energy combined with a Global Adjustment (GA) charge applied at the end of the month (the GA charge covers the fixed costs of installing and maintaining generation capacity and is explained in more detail in the following section). The combined per unit cost for large customers has increased from $55/MWh in 2009 to $126/MWh in 2019 – amounting to a more than 100% increase. In 2011 the province introduced the Industrial Conservation Initiative (ICI program to reduce, or eliminate altogether, the GA charges for large customers. Over time, the number of customers that qualify to participate in the ICI program has grown. This analysis does not include cost reductions as part of the ICI program, although we recognize that cost reduction can be significant for large loads. Those costs are not eliminated from the system in the short-term, but rather shifted to small volume customers.

Figure 1 - Total Commodity Cost ($/MWh)



In response to higher electricity prices, the province has introduced a number of programs over the last decade in an attempt to mitigate their impact on customers and the overall economy.

- **Clean Energy Benefit**: The province introduced the Clean Energy Benefit in 2011, providing small volume customers – including households, businesses and farms – a 10% rebate on their electricity bills. The rebate was explicitly intended to help customers "manage rising costs, especially for electricity". The rebate expired in 2015.

- **ICI Program**: In 2011, the province introduced the ICI program, splitting Ontario customers into two classes for the collection of GA costs: Class A (large volume, predominantly industrial customers); and, Class B (small volume customers). Class A customers pay GA costs for the following year based on their share of demand during the five peak hours. Any percentage of GA costs avoided by Class A customers are shifted to Class B customers. By 2017, nearly $5 billion in costs were shifted from Class A to Class B customers as a result of the ICI program, according to OEB's Market Surveillance Panel (MSP).[1] The potential cost savings to customers who qualify for the ICI program can be significant – as much as $520,000 in GA charges for every MW in peak reduction.

- **Fair Hydro Plan**: The Fair Hydro Plan was introduced in 2017 and reduced electricity bills by 25% for small customers by using tax revenue to provide rate relief. While the Fair Hydro Plan reduced costs in the short-term, the government financed that reduction through long-term borrowing – meaning future customers were going to pay more in order to lower rates today. The Fair Hydro Plan also removed the harmonized sales tax (HST) from electricity bills and shifted the cost of a

[1] See the MSP's ICI report: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

number of social programs, such as the Ontario Electricity Support Program and the Rural or Remote Rate Electricity Rate Protection plan (RRRP) to taxpayers. In 2019, the current government replaced the Fair Hydro Plan with a new subsidy and bill presentment structure, but maintained ongoing subsidies for Regulated Price Plan (RPP) customers.

- **Off-Peak TOU Rates**: In response to the COVID-19 pandemic, the province invoked the *Emergency Management and Civil Protection Act*, which mandated that customers pay the off-peak rate of 10.1 ¢/kWh for all hours of consumption, beginning on March 24, 2019 and to remain in place for 45 days. As of June 1, Ontario moved to a fixed rate of 12.8 ¢/kWh which will be maintained until October 31, at which point customers will be able to choose between a flat or tiered rate.

2.2 How Falling Demand Increases Electricity Rates

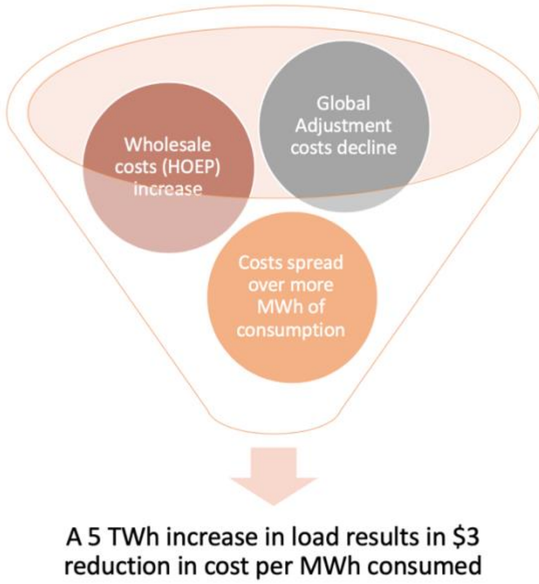
Given the increase in fixed costs (described in more detail in Appendix B), the impact of falling demand on electricity bills in Ontario has been significant. To quantify this impact, Power Advisory estimated what wholesale electricity costs – Hourly Ontario Energy Price (HOEP) plus GA and Capacity Based Recovery charges – would be, or would have been, if Ontario demand had been 5 TWh higher.

Several scenarios were run with different assumptions regarding the type of electricity demand being added: industrial/mining (with very similar demand in all hours of the year); electric vehicle (EV) charging (with some variation depending on time of day and day of the week); using electricity for heat pumps (varying with temperature); etc. As discussed below, demand type had fairly little impact on system-wide costs, but a moderate impact on how changes affected Class A versus Class B customers.

Overall, a 5-TWh increase in Ontario's electricity demand in 2019 would have reduced system-wide costs per MWh consumed by approximately $3/MWh, or 3%. The increase would have the following impacts:

- Average annual HOEP would increase by approximately $2/MWh (10%);
- GA and Capacity Based Recovery costs would fall (by approximately 3%), because generators would receive more wholesale market revenues, but less contract revenues;
- Combining the impact of higher HOEP and lower GA and Capacity Based Recovery costs, total system costs would increase, but only slightly (0.4%); and,
- This increase in costs would be spread over more loads (approximately 3.5% higher), so the cost per MWh would fall by approximately 3%.

Figure 2 Impact on Electricity Prices Due to Increased Demand



Both Class A and Class B customers would benefit from an increase in demand, but how the benefit was split would depend on the type of load. For example, if the demand increase was due to increases in Class A baseload demand (e.g., approximately 570 MW of around-the-clock mining or large industrial load), and if these Class A customers were able to limit their demand during top 5 peak hours to half of their average demand (through conservation and demand management (CDM), energy storage, on-site generation, etc.) then most of the benefit would accrue to this new load. Nonetheless, Class B customers would see their wholesale costs fall by approximately $2/MWh (1.3%). On the other hand, if the new demand were due to increased demand by Class B customers, then Class B customers (both existing and new load) would see a $5/MWh (4%) reduction in their wholesale electricity costs, while Class A customers would see a $1/MWh (2%) reduction in theirs. Larger demand increases would have correspondingly greater impacts on reducing per-MWh costs of both Class A and Class B customers.

Similar analyses were done on future costs, using 2022 and 2026 as test years. The impact of demand increases in 2022 were similar to the impacts in 2019. In 2026, the impacts were still significant (approximately $2/MWh, or 2%). However, the retirement of the Pickering nuclear generation station will leave the province with less surplus generation, so the incremental system-wide cost of serving the additional demand would be small but not negligible (as it would be in 2019 and 2021).

In all of the test years (2019, 2022 and 2026), increasing demand of any type was found to reduce per-MWh wholesale charges for both Class A and Class B customers.

3. POLICIES IN NEIGHBOURING JURISDICTIONS ENCOURAGING INCREASED ELECTRICITY CONSUMPTION

Load growth programs are common across North America. More specifically, a number of neighbouring jurisdictions with large industrial or manufacturing sectors have implemented a variety of programs to both increase electricity demand and spur economic development

3.1 Positive Feedback Loop from Load Growth Incentives

Contrary to policies that shift costs from one rate class to another or require taxpayer funding, load growth programs can create a positive feedback loop that benefits all customers. First, they increase the overall demand on the system, which can help reduce the cost of each unit for all customers – both small and large. Second, they support short-to-medium term economic development that can create or sustain jobs and support the overall economy – and subsequently incent further load growth and lower per unit costs for all customers. In Ontario, given the province typically has surplus generation in many hours and months throughout the year, an increase in demand can also improve the overall efficiency of the grid by utilizing energy that is often curtailed or exported below its long-term cost.

Price Elasticity in the Electricity Sector

Electricity consumption is responsive to changes in price, particularly over the long-run (i.e. one-year or more). As such, an increase in overall load in Ontario – and a subsequent reduction in the per unit price paid by customers, as detailed in the previous section – will result in even greater consumption. This creates a positive feedback loop.

Price elasticity in the electricity sector has been extensively studied in economic literature around the world utilizing data from a variety of market and geographical settings. Most studies show that consumers adjust consumption in response to changes in price. A recent study based on data from Illinois found a one-year price elasticity of -0.14 and a three-year price elasticity of -0.29. These figures suggest that a 10% decline in price produces a 1.4% and 2.9% increase in demand over a one and three-year period, respectively.[2] Interestingly, the study found that consumers responded to *anticipated* price changes. Given the similarities in market and geographic structure between Illinois and Ontario – both regions are part of a wholesale market and experience similar weather patterns – these estimates are likely indicative of what would occur in Ontario.

Combining these figures with estimates from Section 2.2, if load growth programs were able to increase overall demand in Ontario by 5 TWh, producing a 3% reduction in price for all customers, the subsequent increase in demand as a result of price elasticities would be more than 1 TWh by the third year. Given that

[2] The Long-Run Elasticity of Electricity Demand: Evidence from Municipal Electric Aggregation, Tatyana Deryugina, Alexander MacKay and Julian Reif, May 2, 2017, https://www.econ.pitt.edu/sites/default/files/Deryugina.Electricity%20Aggregation.pdf

most costs in Ontario's electricity sector are fixed, any increase in overall demand (and lower price per unit) as a result of load growth programs creates further price reductions for consumers.

3.2 Survey of Neighbouring Jurisdictions

Power Advisory undertook a survey of Canadian provinces and select U.S. states to review available programs that either directly or indirectly promote economic development through incentives that increase electricity demand. Power Advisory also sent out a questionnaire and conducted interviews with a number of program administrators to gather further details. The following jurisdictions were surveyed (see Appendix A for a detailed description of the programs reviewed).

Table 1 Jurisdictions Surveyed

USA	CANADA
New York	Ontario
Michigan	Alberta
Ohio	Quebec
Pennsylvania	Nova Scotia
Minnesota	New Brunswick
Wisconsin	Newfoundland & Labrador
Indiana	British Columbia
Illinois	Manitoba
	Prince Edward Island
	Nunavut
	Saskatchewan
	Yukon

The survey focused on available programs that were administered by utilities, overseen by provincial/state regulatory agencies, and provided incentives for economic development. In discussions with program administrators, it was noted that a number of demand incentives were introduced by utilities as a means to generate additional revenue, with the regulatory body overseeing these utilities ultimately approving the programs and limiting cross-subsidization between customer classes. The survey found that most incentives were provided through loans for economic development, low-cost electricity as an incentive to undertake capital investments, and job creation or electric rate riders that reduce demand charges when demand increases to pre-determined thresholds. Some provinces/states provide some combination of all three. Our analysis and recommendations excluded the option of providing loans for economic development. In general, U.S. states have more programs that fit the above criteria than Canadian provinces.

Many U.S. jurisdictions in the survey have introduced utility-supported economic development incentive riders for eligible customers in their service territories. Utility development incentive riders are typically provided as billing credits per KW or as direct rate reductions. For example, under this program, a utility offers a large customer a reduction in their per KW or MW demand charge if they either add new load to the system (i.e. build a new facility) or increase load at a current facility. In many cases, the reduction in demand charges is tied to employment or investment thresholds – the new jobs must be maintained for one or more years, for example, or the investment must be greater than $1 million.

New York in particular has the highest number of programs that promote economic development through increased load. These programs are largely administered by the state-owned New York Power Authority (NYPA) and, in some cases, regional development agencies.

As discussed in the following section, given the similarities between the New York and Ontario electricity markets, as well as the similar ownership structure, the highlighted NYPA program may be particularly well-suited in Ontario. This NYPA program, allocates as much as 695 MW of low-cost hydroelectric energy from the Niagara Project Power in Lewiston (across the river from the OPG owned Sir Adam Beck hydroelectric generation station on the Niagara River) to either new businesses in the region or existing businesses considering an expansion of their facilities. The businesses must meet certain thresholds to qualify for this program – including new jobs or capital investments. Additionally, NYPA allocates as much as 490 MW of low-cost energy from its hydroelectric generation facilities on the St. Lawrence to businesses in the region. Similar to the allocation from Niagara Project Power, qualifying businesses must meet certain thresholds of job creation or new capital investment.[3]

In total, there are 13 load incentives in New York alone.

The Canadian provinces that have some direct or indirect development incentives are Ontario, Manitoba, British Columbia, and Quebec. Quebec provides government assistance to eligible projects through reduced electricity costs and Hydro-Quebec provides special development rates to its customers who can bring on an incremental electricity demand. Incentives in Manitoba and British Columbia are administered by the province of Manitoba and BC Hydro, respectively. The BC Hydro incentive is geared to large electricity customers and the Manitoba incentive is geared toward attracting capital investment to the province. BC Hydro also provides a market-based rate during months of surplus capacity.

3.3 Making Ontario More Competitive

All of Ontario's neighbouring jurisdictions have introduced some form of a load growth program. While the program structures may vary between jurisdictions, many of them are similar in form and implementation – largely offering reduced demand charges or allocations of low-cost power.

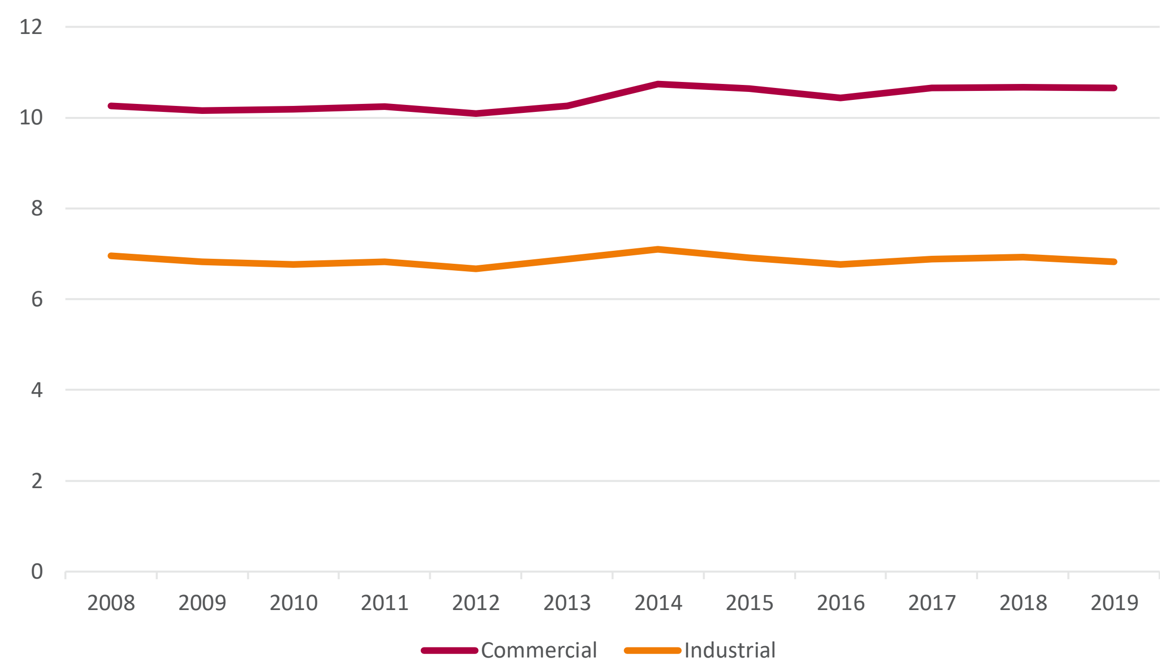
[3] See the "2019 Report to the Governor and Legislative Leaders on Power Programs for Economic Development" for more details: https://www.nypa.gov/-/media/nypa/documents/document-library/governance/2019ecodevgov.pdf

Affordable and competitive electricity rates are a key ingredient to the success of both the province's business community and overall economy. The importance of affordable electricity is even more important given the challenges facing businesses in the wake of the COVID-19 pandemic.

Business leaders in Ontario have repeatedly highlighted the impact that faster-than-inflation rate increases are having on operations and investment. Ontario's Chamber of Commerce, for example, reported that more than 60% of its members cited electricity costs as critical to their competitiveness.[4] This industry group previously estimated that one in 20 businesses and industries in the province are expecting to shut down or reduce operations due to electricity prices.[5] Other energy-intensive businesses have either expanded operations elsewhere or reconsidered investments in Ontario due to electricity prices.[6]

In contrast, commercial and industrial electricity prices in the U.S. – home to numerous jurisdictions that directly compete for investment with Ontario – have either declined or remained at the same level during the 2008-2019 period.

Figure 3 – U.S. Commercial and Industrial Electricity Prices (cents/kWh)[7]



4 https://occ.ca/wp-content/uploads/Industrial-Electricity-Rates.pdf

5 https://www.theglobeandmail.com/news/national/skyrocketing-electricity-rates-wreaking-havoc-with-ontario-businesses/article25348882/

6 https://www.thestar.com/business/2016/12/20/toronto-company-opening-us-plant-because-of-rising-ontario-electricity-rates.html

7 Source: EIA annual average electricity retail price:

3.4 Equity Between Customers and Free Ridership Concerns

Well-structured load growth incentives provide benefits to all customers (as discussed previously) and should not result in significant cross subsidization between customers or high levels of free-ridership. In discussion with administrators of similar programs in other jurisdictions, they highlighted that the programs provided additional revenues that previously were not available to the utility – helping to reduce costs for all customers. Many of the programs are also reviewed and approved by regulators to ensure economic viability and fairness.

Free-ridership related to load growth incentives – defined as a situation where customers that were already going to make an investment take advantage new and existing incentives – has long been a focus of regulators. To counteract concerns about free-ridership, a number of load growth programs surveyed in other jurisdictions require a threshold for new investment or employment levels over a pre-determined time frame in order to qualify for the programs. Such threshold requirements can help prevent smaller investments that would have occurred without the incentive from qualifying, ensuring a sustainable, long-term increase in local employment and investment, while providing the greatest benefit to existing customers through a noticeable increase in incremental load (and subsequent lower per unit costs for all customers).

4. RECOMMENDATIONS

Given that load growth programs are common in all neighbouring jurisdictions, Power Advisory screened the programs reviewed as part of the jurisdictional survey. As part of the screen, the incentives were narrowed based on a set of criteria:

- Do the programs specifically target large increases in demand to ensure maximum impact on the province's electricity sector?
- Can the programs be implemented by Local Distribution Companies (LDCs), or wholesale Market Participants?
- Do the programs have a proven track record of success?
- Do the programs provide direct incentives to participating customers?
- Can the programs be scaled quickly and easily based on their effectiveness? Can they be implemented quickly and set for short and long time periods?

As a result of this screening process, Power Advisory recommends two programs be considered for Ontario. These programs are all found in neighbouring jurisdictions and, in most cases, have been in place for decades. As such, they are not "made-in-Ontario" policies, but rather common utility programs that can help lower costs and improve Ontario's economic competitiveness.

Greater detail on these programs and how they might be introduced in Ontario are provided below.

1. **A reduced demand charge for customers that provide either new demand in Ontario or increase current levels of consumption**

   Ontario may consider allowing LDCs to offer demand charge reductions to new or existing businesses that provide incremental demand to the system, based on defined set of criteria – either in the form of new jobs in the province or capital investment. The demand charge reductions should be reviewed by the OEB to ensure they do not require cross subsidies – or capital costs for new or expanded facilities – from existing customers. Based on surveys with program administers of similar programs in the U.S., the new demand provides additional revenue to applicable utilities, while also increasing the number of units sold – thereby providing lower costs to all customers. The programs should, at the outset, focus on large facilities with a demand threshold of 1 MW or higher for at least one year, but possibly for longer durations given that price elasticities are higher over longer periods. If the program is successful in attracting applicants and providing measurable rate reductions, the threshold can be lowered going forward.

2. **Low-cost allocations of energy**

   The low-cost allocation of surplus energy offered by NYPA to local businesses could be the basis for a similar program in Ontario. Ontario has numerous generation facilities across the province, notably large-scale baseload facilities in the Niagara and St. Lawrence regions directly adjacent to NYPA's facilities that currently provide low-cost allocations to businesses in nearby municipalities. Ontario continues to have an ongoing prevalence of surplus generation supply, which provides excess energy output compared to demand in Ontario. In many hours that energy output is sold below cost to neighbouring jurisdictions – often at $0/MWh – or generators are paid to curtail operations, either by spilling water or being dispatched down by the Independent Electricity System Operator (IESO). Instead, a portion of that energy output could be allocated to large customers creating additional demand (LDCs can also be considered) at a pre-determined rate. As such, that additional revenue – compared to either selling it well-below cost over the interties or simply spilling water – may help reduce overall system costs for all customers. Given the geographic range of low marginal cost generators (among others), the program could be implemented in various regions across Ontario.

5. APPENDIX A

Below is a detailed description of the programs reviewed as part of our jurisdictional survey.

Table 2 Highlights of the Jurisdictional Survey

Jurisdiction	Description
New York	New York offers a number of direct and indirect subsidies to large customers. • The Industrial Economic Development Program, Preservation Power, ReCharge NY, St. Lawrence County Economic Development Power (SLCEDP) and the Expansion Power (EP) and Replacement Power (RP) all allocate blocks of energy to regional and statewide businesses for economic development purposes. The allocations are overseen by the NYPA and, in some cases, regional development agencies. Collectively, these programs provide over 1,000 MW of cheap energy to businesses and other electricity customers. • The Niagara Economic Development Fund provides direct loans for the expansion or maintenance of plants or facilities if the project will increase load and the low-cost energy results in an economic benefit to the region. • The Electric Capital Investment Incentive Program provides funds for facilities to expand or launch a new project. • The Three-Phase Power Incentive Program provides funds to expand three-phase service to predominantly rural customers. • The North Country Economic Development Fund is jointly overseen by the NYPA and a regional development agency and provides loans and funds to businesses expanding operations or creating new jobs. • The Northern New York Power Proceeds Allocation Board in conjunction with a development agency provides funds for capital investment projects in northern regions of the state. • St. Lawrence River Valley Redevelopment Agency (RVRDA) oversees funds from the NYPA to support economic development projects. • The Western New York Power Proceeds Allocation Board (WNYPPAB) also oversees funds from the NYPA to support economic development projects in western regions of the state.
Michigan	• 'The Economic Development Rider 2019 offers a bill reduction of up to $11 per kilowatt to new and expanding businesses. The customer must have a billing demand of 500 kw/kVA or, if they are an existing customer, increase their billing demand by that amount. The investment must add ten or more full-time employees or $1 million capital improvements. The project must also be competitive – meaning it could have been made in other jurisdictions – and supported by local, state or other development agencies.

Jurisdiction	Description
Ohio	• Ohio provides the Development Incentive Rider, which consists of three separate programs to encouragement new and existing developments: the Economic Development Program, the Urban Redevelopment Program and the Brownfield Incentive Program. The programs provide up to a 50% reduction on monthly distribution charges. • For new or expanding businesses, the Economic Development Program must produce an additional 25 full-time employees and the increase in load must result in at least $1 million in capital investment at one of the company's facilities. The new employee requirement is waived if the company invests $10 million. Existing customers must agree to maintain employment levels for at least one year. • The Urban Redevelopment Program is targeted for facilities or investments that produce an additional 500 kW of new load. • The Brownfield Development Program is applicable to developments in recognized "brownfield" areas.
Illinois	• Illinois has introduced dozens of programs that provide price reductions for facilities or customers that increase load. The credits range from lower monthly demand charges to lower block rates for energy. The reductions are available to both new and existing customers.
Pennsylvania	• The PECO Development Rider provides a rate rider to loads of at least 350 kw to support businesses and "encourage environmentally sustainable growth." The credit can reduce monthly variable demand charges by up to 15%. • The PECO Economic Development Rider-Competitive Alternative provides a rate rider to both manufacturing and non-manufacturing businesses that can demonstrate a viable alternative to service from PECO, demonstrate an increase in load of at least 1 MW and increased in employment of at least 10 jobs per MW of load.
Minnesota	• The Xcel Energy Business Incentive and Sustainability Rider reduces the monthly demand charge by up to 40% for new or existing customers with an increase in load of 350 kW or greater.
Indiana	• The Economic Development Rider provides a bill reduction of up to $12 per kW for new or existing customers that increase load by 300 kW. Eligible participants must have received assistance from a public agency and show that the investment would not have occurred without the rate rider.

Jurisdiction	Description
Quebec	• The Electricity Discount Program allows customers on the industrial rate to recover up to 50% of an investment through lower electricity rates. The maximum annual reduction in electricity rates is capped at 20%. Investments eligible for the discount include new facilities, increased output, a conversion in production processes or energy efficiency and modernization upgrades.
Manitoba	• The Manitoba government created a $30 million fund to provide "flexible" loans to businesses that expand to establish new operations in the province. The program is not a load growth incentive to help manage the province's ongoing capacity surplus.
British Columbia	• In 2016 BC Hydro introduced a Freshet Energy Rate, which provided an incentive to large industrial users to increase consumption during peak supply months. As part of the new rate, large consumers pay a market-based rate for incremental energy during freshet months when energy prices are typically depressed. The rate is explicitly intended to absorb the province's surplus energy, while providing a financial benefit to participating and non-participating customers. The rate includes a price floor and an adder of $3 per MWh to ensure that customers contribute to BC Hydro's fixed costs even when prices are low or negative. The British Columbia Utilities Commission determined that the rate provided a net benefit to all ratepayers.

6. APPENDIX B

Below is a detailed history of changes in Ontario's electricity sector that have resulted in the price increases described in this report.

Breakdown of Electricity Bills in Ontario

Electricity bills in Ontario are made up of a variety of components, including the commodity cost of generating electricity, the cost of delivering energy over short and long-distance wires (i.e., distribution and transmission), and various regulatory charges. The percentage of the total electricity bill and the final cost of each of these components varies between rate classes of customers (small versus large) and consumption patterns (off-peak versus on-peak).

A number of these charges are also impacted by provincial policies that may shift costs from one rate class to another, as is the case with ICI and the RRRP plan. The province also directly subsidizes electricity bills for small-volume customers through funds appropriated from the legislature (i.e., tax revenues).[8] Table 1 provides an overview of the components of costs that makeup a standard electricity bill in Ontario.

Table 3 Breakdown of Ontario Electricity Bills

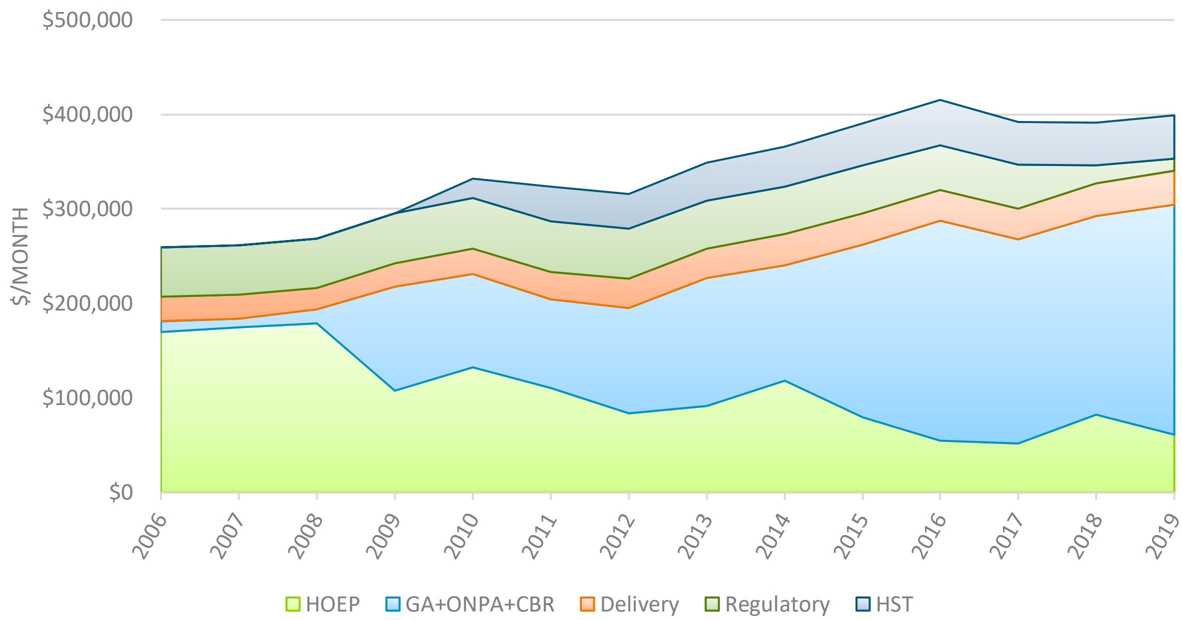
Wholesale Market Costs: *The wholesale cost of electricity to Ontario customers is the sum of the HOEP and the GA.*	**Hourly Ontario Energy Price (HOEP)**	The commodity electricity price for Ontario set in the province's wholesale electricity market.
	Global Adjustment (GA)	The cost of regulated and contracted generators, along with CDM programs. The GA charge is inversely related to HOEP.
Delivery Charges: *The cost of delivering electricity from generating stations to customers via long-distance transmission and local distribution lines.*	**Customer Service Charge**	Fixed charge for costs relating to meter reading, billing, customer service and account maintenance, and general utility operations.
	Distribution Charge	A fixed charge covering the cost of building and maintaining local distribution systems, including overhead and underground power lines, poles, and transformer stations. Some distribution utilities may still use a variable delivery charge.
	Transmission Charge	Variable charge covering the costs of transmitters to operate and maintain long-distance high-voltage transmission lines.

8 This includes the Ontario Electricity Rebate, Distribution Rate Protection, First Nations Delivery Credit and the Ontario Electricity Support Program

Regulatory Charges: *The regulatory charge comprises two components which are approved by the Ontario Energy Board (OEB).*	**Wholesale Market Service Charge**	Charge predominantly for the services provided by the IESO to operate the wholesale electricity market and maintain the reliability of the high voltage power grid.
	Standard Supply Service Charge	Charge covers part of a utility's administrative costs to provide electricity to customers that are not served by a retailer.

The two largest components of electricity bills – both for small volume customers, including residential and small businesses, and large industrial customers – are wholesale market and delivery charges. For large volume customers, wholesale and delivery charges account for the majority of costs in a typical monthly bill. The commodity cost of electricity accounts for around 75% of the total bill, while delivery charges account for around 10%.

Figure 4 – Electricity Bill Breakdown for Large Industrial Customers



Drivers for Electricity Price Increase

Two of the main drivers for the increase in electricity prices over the past decade relate to the fall in overall grid-connected demand for electricity and the overhaul of the Ontario's generation fleet, which included the closing all of the province's coal-fired generators in tandem with the refurbishment of nuclear generating units combined with large-scale procurement of gas-fired and renewable generation. Current forecasts suggest that demand has declined significantly as a result of the recent downturn in the economy in response to the COVID-19 pandemic. This downturn may result in a 'new normal' of lower demand going forward.

The Current Landscape of Ontario's Electricity Market

The largest bucket of costs for all customers relates to the province's electricity market. Ontario's electricity system, particularly its competitive wholesale market, has undergone a series of significant changes since it was launched in May 2002. The makeup of the generation fleet has evolved and incorporated the large-scale integration of gas-fired and renewable generation that are compensated through long-term contracts, and demand has decreased over the last decade. Grid-connected demand now sits at a level last seen in the 1990s.

The impact on customer bills as a result of these changes – particularly the combination of falling demand and an increase in long-term fixed costs through generation contracts – has been significant.

The "Hybrid" Market and Rise of Fixed Costs in Ontario's Electricity Sector

Most energy in Ontario flows through the province's wholesale market. This market is often referred to as a "hybrid" market, due to the combination of generators under rate regulation or contracts that provide guaranteed 'out-of-market' payments to cover fixed costs of building capacity in tandem with the operation of a spot market for energy. Regulated rates are set by the OEB for OPG's baseload nuclear and hydroelectric generators (including the Beck pumped generation storage) and vast majority of contract payments are administered by the IESO as the province's main contract counterparty with generators.

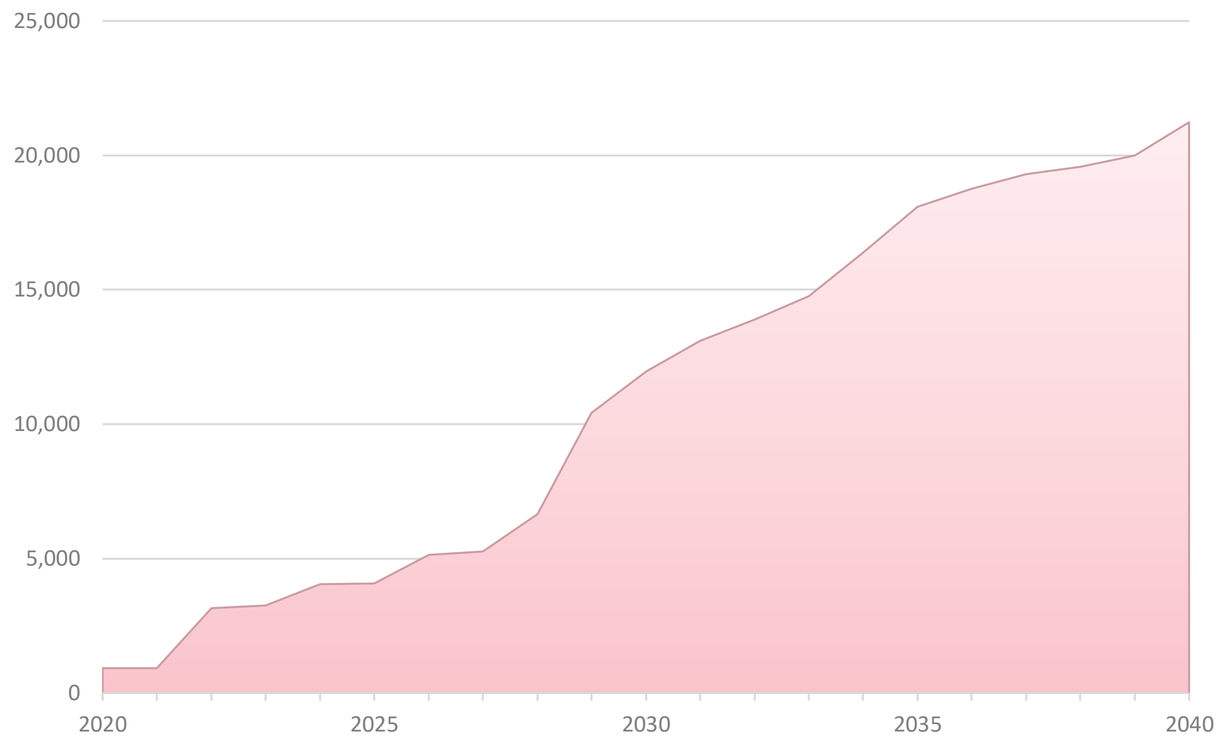
In conjunction with out-of-market payments are revenues earned by generators from selling energy in the province's wholesale market – the "spot" market. Wholesale market revenues typically recover the short-term operating costs of producing each unit of energy. Wholesale market revenues and out-of-market payments are inversely related – higher wholesale energy prices (and revenues) reduce the amount of out-of-market payments made to generators.

When Ontario's wholesale electricity market opened in May 2002, it was expected that wholesale market revenues would be the primary source of revenue for generators. These revenues were intended to cover both short-term and long-term costs of building and maintaining capacity in Ontario – a framework commonly referred to as an "energy-only" market. In this system, wholesale prices would provide a transparent signal to investors and system planners when deciding whether to build or maintain generating capacity. The need to add or retire capacity under this model would be a dynamic process determined by prices in the wholesale market. Lower demand – and lower prices – would see capacity retire, while an increase in demand (and prices) would incent new capacity to be added to the grid.

But for a variety of reasons – ranging from provincial priorities to broader changes in electricity markets – the role of the wholesale market on investment and the entry and exit of capacity in Ontario has been replaced by out-of-market payments set through rate regulation by the OEB or contracts with the IESO. In many cases, the amount and type of rate-regulated and contracted capacity was directly influenced by provincial directives and the legislature – often for broader environmental or socio-economic purposes.

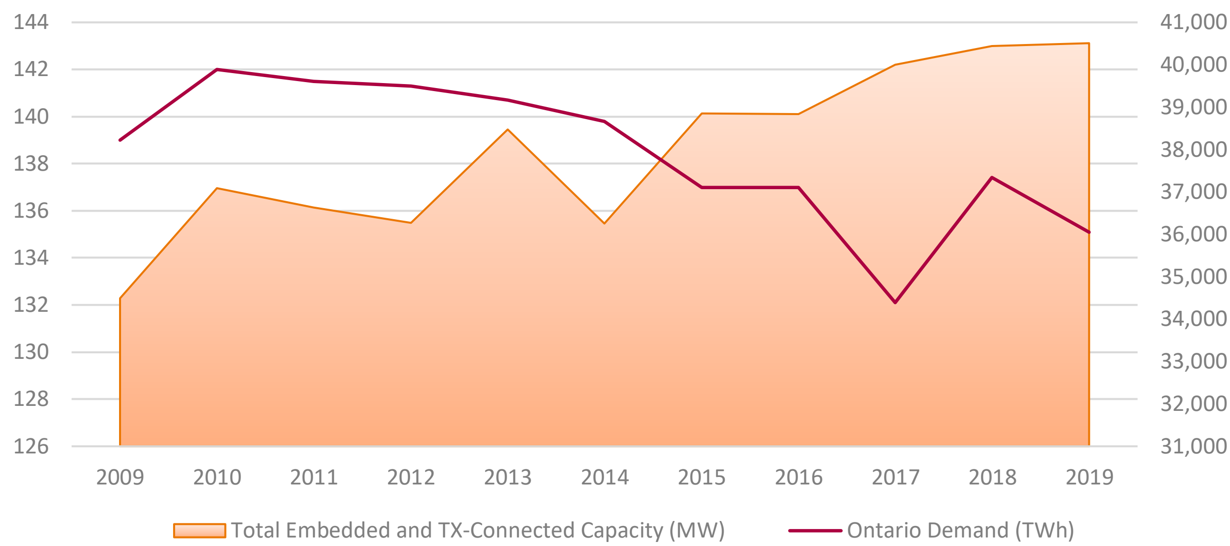
Currently, nearly all of the grid-connected capacity in Ontario is rate-regulated by the OEB or contracted with the IESO. More than 12,100 MW of nuclear and hydroelectric generation owned and operated by OPG, who is provincially-owned, has rates set by the OEB. The majority of the remaining generation capacity – from gas-fired generators, the Bruce nuclear generation facility, and renewable generators – have contracts with set contract prices. In the case of contracted capacity, nearly all contract prices are for terms of 20-years or longer. While the rate-regulated generators are reviewed by the OEB every three to five years, the "need" for that capacity is determined by the Ontario government and is expected to largely remain in operation over the medium- and long-term. The terms of the majority of contracted generators do not begin to expire until the end of this decade – meaning Ontario will continue to have a large percentage of fixed costs for the long-term.

Figure 5 – Cumulative Capacity (MW) with Expired Contracts 2020 – 2040



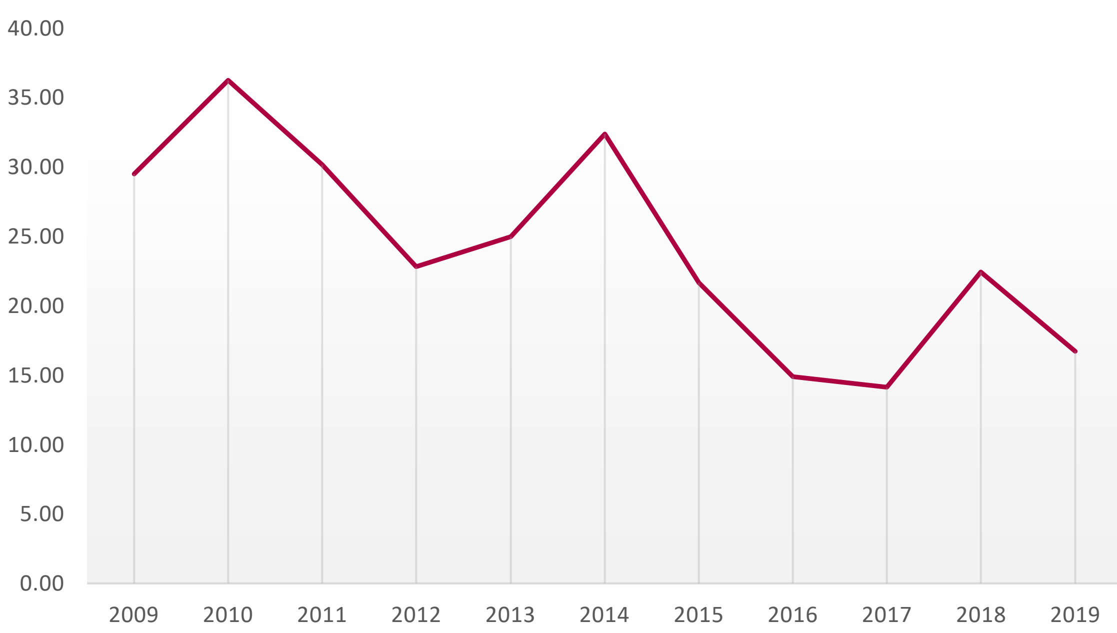
The move from an "energy-only" to a provincially led "hybrid" market ensures that nearly all of the costs related to the generation of energy – i.e., installed capacity – are now fixed for the long-term. While generators would typically retire or mothball their facilities if there was a long-term grid-wide surplus, as has been prevalent in Ontario for the past decade, that has not been the case due to the lack of price responsiveness of the province's hybrid market. Over the last decade, the Ontario electricity market continued to add new capacity to the system while it was facing a capacity surplus.

Figure 6 – Ontario Demand Compared to Installed Capacity



The capacity surplus – combined with the integration of significant amounts of resources with low operating costs (e.g., wind and solar generation) – helped push wholesale prices on the electricity market down. In many hours, the wholesale price has been negative.

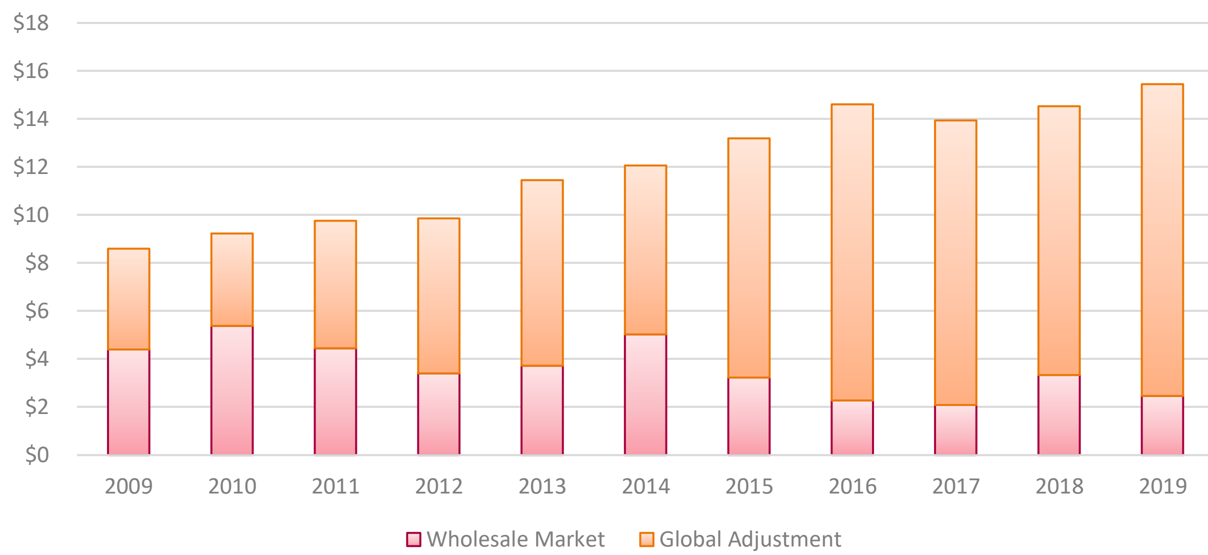
Figure 7 - Average HOEP 2009 – 2019 ($/MWh)



To make up the difference between the cost of building and maintaining installed generation capacity signed to contracts or OPG's generation supported by regulated rates – particularly with the prevalence of low prices in the spot market – Ontario introduced the GA. The GA is a per unit charge paid by customers representing the difference between the fixed costs of capacity and the value of that energy in the wholesale market. It also includes CDM related costs, which account for a small percentage of overall GA costs.

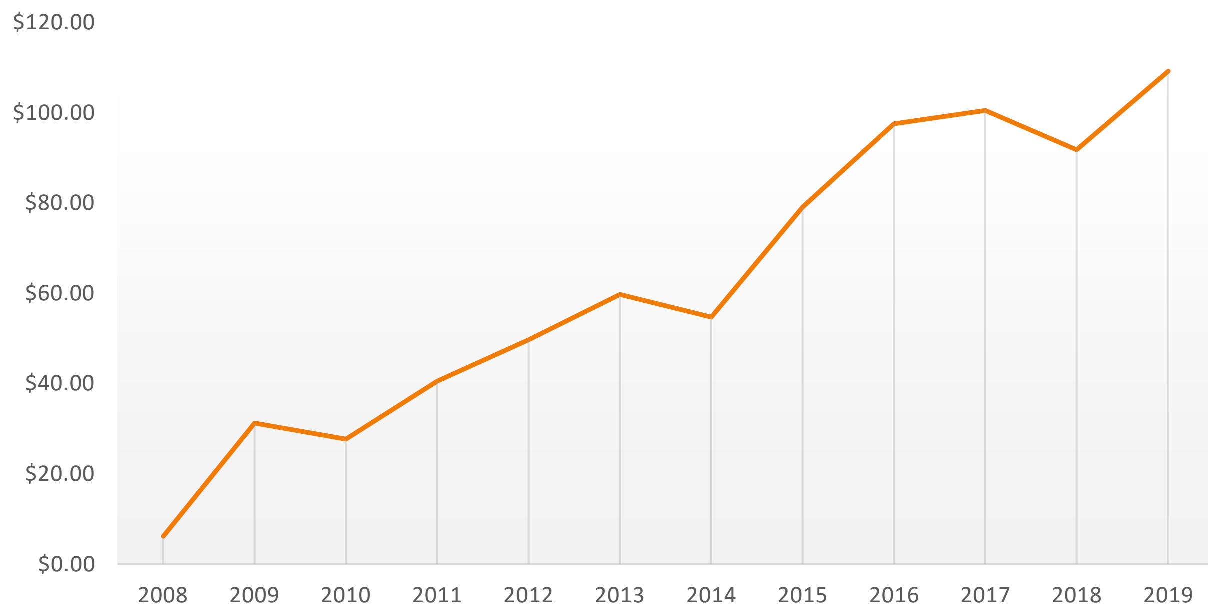
Over the last decade, demand continued to fall while installed generation capacity – and the costs associated with it – continued to grow. As result, the overall costs associated with the province's generation fleet has grown.

Figure 8 – Total System Cost 2008-2019 ($ billions)



As overall system costs continued to increase, so too did the size of the GA charge – growing from $6/MWh in 2008 to more than $109/MWh in 2019, marking a more than 18-fold increase. The GA charge was recently capped by regulation at $115/MWh.

Figure 9 – Global Adjustment Charge 2008 – 2019 ($/MWh)



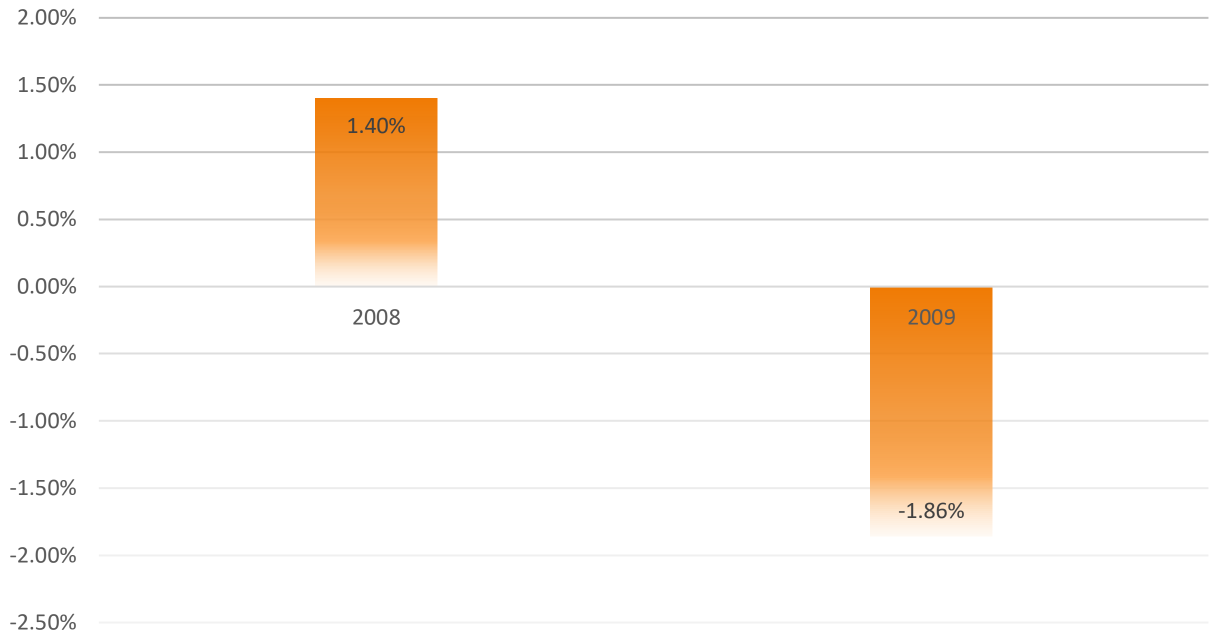
The rise in GA costs – which recovers the guaranteed fixed costs of installing and maintaining generation capacity – combined with falling demand produces higher prices for customers for each unit of energy consumed. As a simplified example, if demand was 100 MWh, while the fixed cost of installed generation capacity was $100/MWh, the price of each unit would be $1/MWh ($100/MWh ÷ 100 MWh). If demand fell to 50 MWh, the price of unit would increase to $2/MWh ($100 MWh ÷ 50 MWh). If fixed system costs, as represented by the GA, grew while demand declined, the price impact would be even more severe for customers ($150 MWh ÷ 50 MWh = $3/MWh). This is explained in more detail in section 2.4.

The last example – falling demand and growing fixed costs – is what occurred in Ontario over the last decade and will continue in the future due to the economic fallout from the pandemic.

Falling Demand

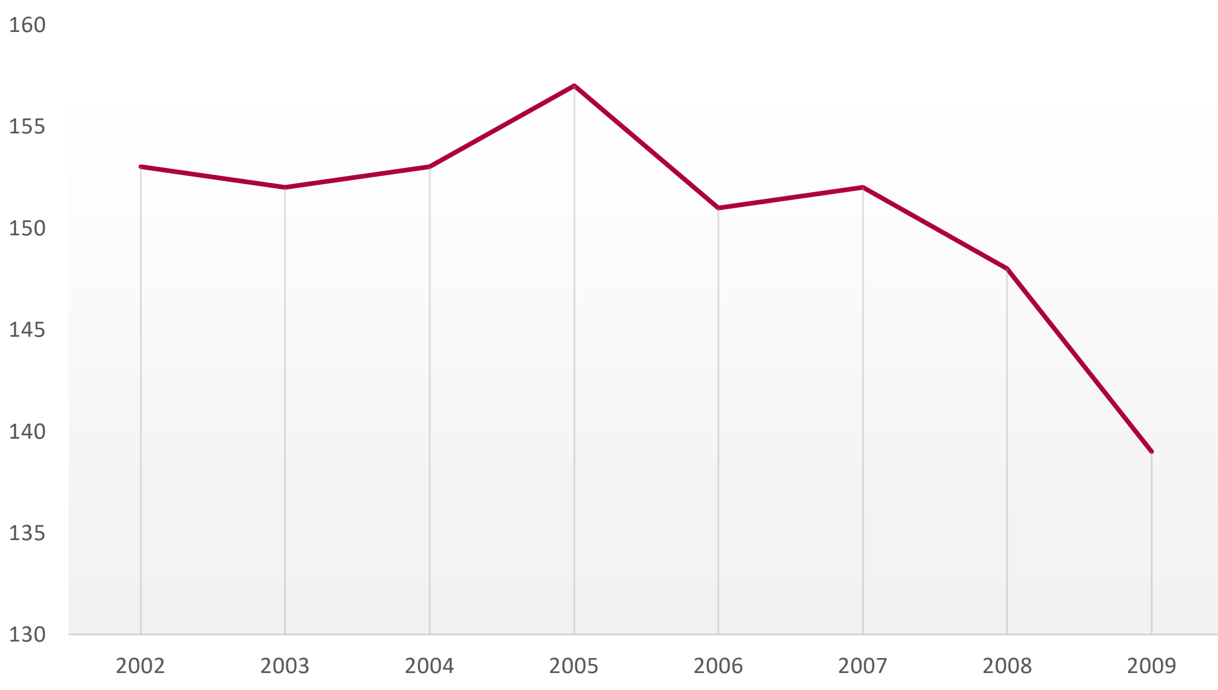
While Ontario was overhauling its generation fleet, electricity demand in the province began a decade-long decline due the fallout from the 2008-09 financial crisis and increased focus – and funding – for electricity CDM programs. The impact on customer bills of falling demand exacerbated the increase in costs associated with overhauling Ontario's generation fleet.

Figure 10 - Reduction on Ontario GDP 2008 - 2009



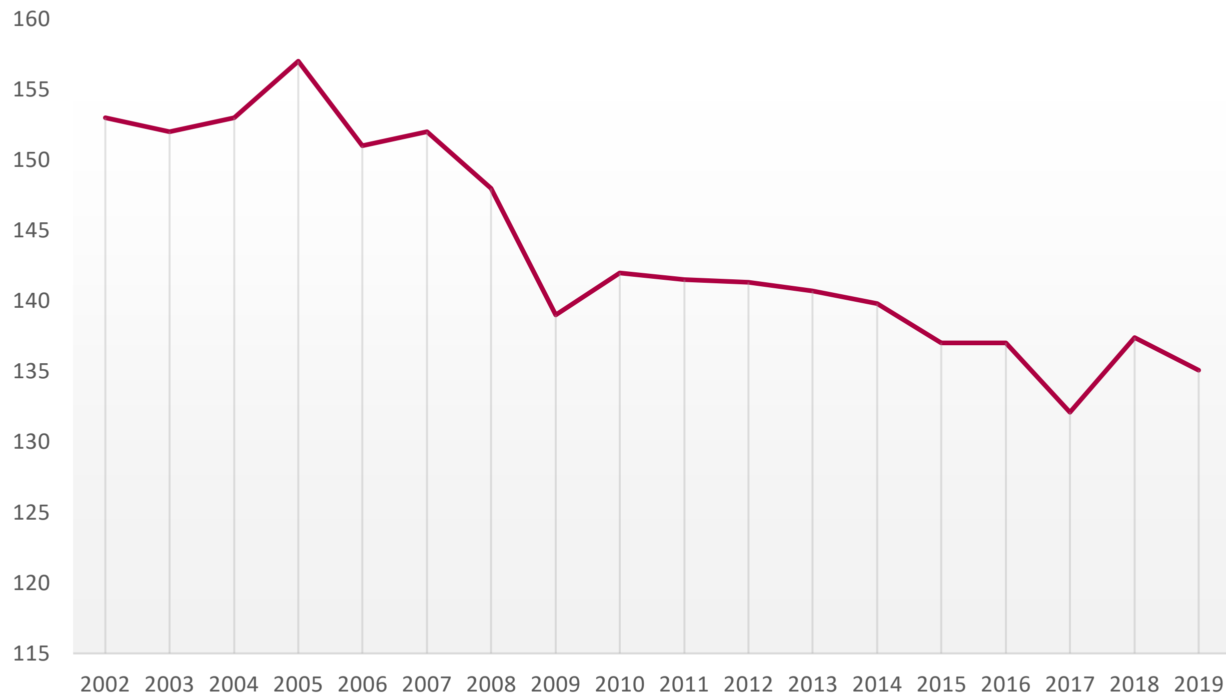
In 2007, the total demand for electricity in Ontario was 152 TWh. Two years later, in the midst of a severe financial crisis and economic downturn, Ontario demand dropped to 139 TWh – a decline of 8.5%.

Figure 11 - Ontario Demand 2002 – 2009 (TWh)



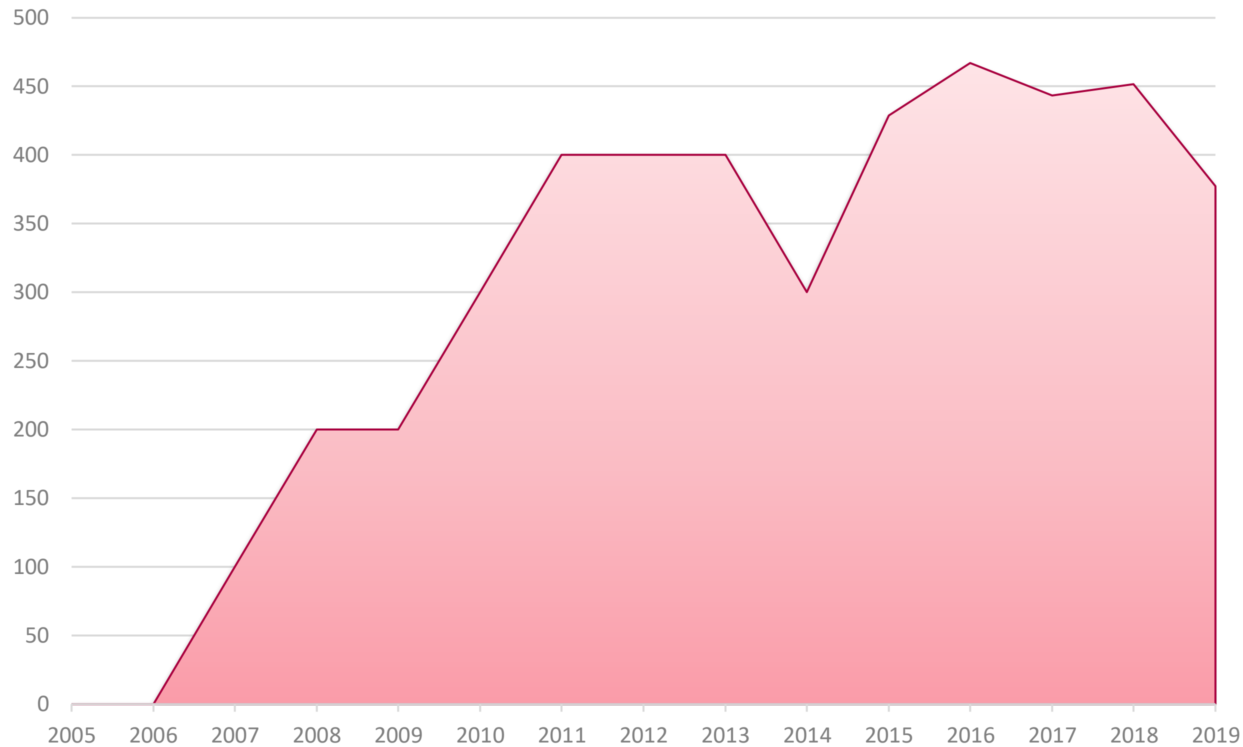
While demand increased slightly in 2010 to 142 TWh, it has largely declined on an annual basis every year since. In 2019, demand was 135.1 TWh. The COVID-19 pandemic is likely to result in a material decrease in demand. Early analysis from the IESO shows overall demand since the pandemic began is down by as much as 18%, while peak demand has declined by as much as 15%.

Figure 12 - Ontario Demand 2002 -2019 (TWh)



Over the past decade the province has placed greater emphasis on CDM programs and funding – while it continued to add more generation capacity to the grid. The cumulative savings from CDM programs have grown more than threefold – from 4.9 TWh in 2009 to 18.1 TWh in 2018. The savings from CDM programs are a direct result of a significant increase in funding over the past decade. In 2009, the annual cost of CDM programs funded from the GA was around $200 million, growing to $377 million in 2019. The most notable conservation program was the Conservation First Framework, which allocated $2.1 billion to CDM programs over the 2015-2020 timeframe.

Figure 13 – Conservation and Demand Management Spending ($ millions)



But CDM programs can have a negative impact on electricity rates if the system is loaded with fixed costs, as is the case in Ontario. This is not a criticism of CDM, which can be economic compared to building new generation capacity or other capital investments. Rather, it is a recognition that the combination of CDM, a reduction in demand due to wider economic factors and an increase in fixed costs (and installed generation capacity) can impact prices paid by customers. In Ontario, the province's CDM programs doubly impact rates, both by increasing the amount of costs that need to be allocated to customers via the GA while simultaneously reducing the number of units that those costs are to be recovered from.

In 2016, the OEB, which sets default supply rates for most small volume customers in Ontario through the RPP, highlighted this phenomenon. When setting rates, the OEB forecasts costs for the next year and then sets rates to recover those costs. If demand drops – or is lower than the OEB forecasts – rates must increase to recover that difference. In its 2016 price-setting report, the OEB noted that "Ontarians consumed less electricity than expected" and this was one of the "main reasons prices are increasing…" In response to questions about how it sets rates, the OEB said "when it comes to [rates] we need to set the costs to recover costs."[9] When demand falls but costs remain the same – or, worse still, increase – the cost per unit naturally rises.

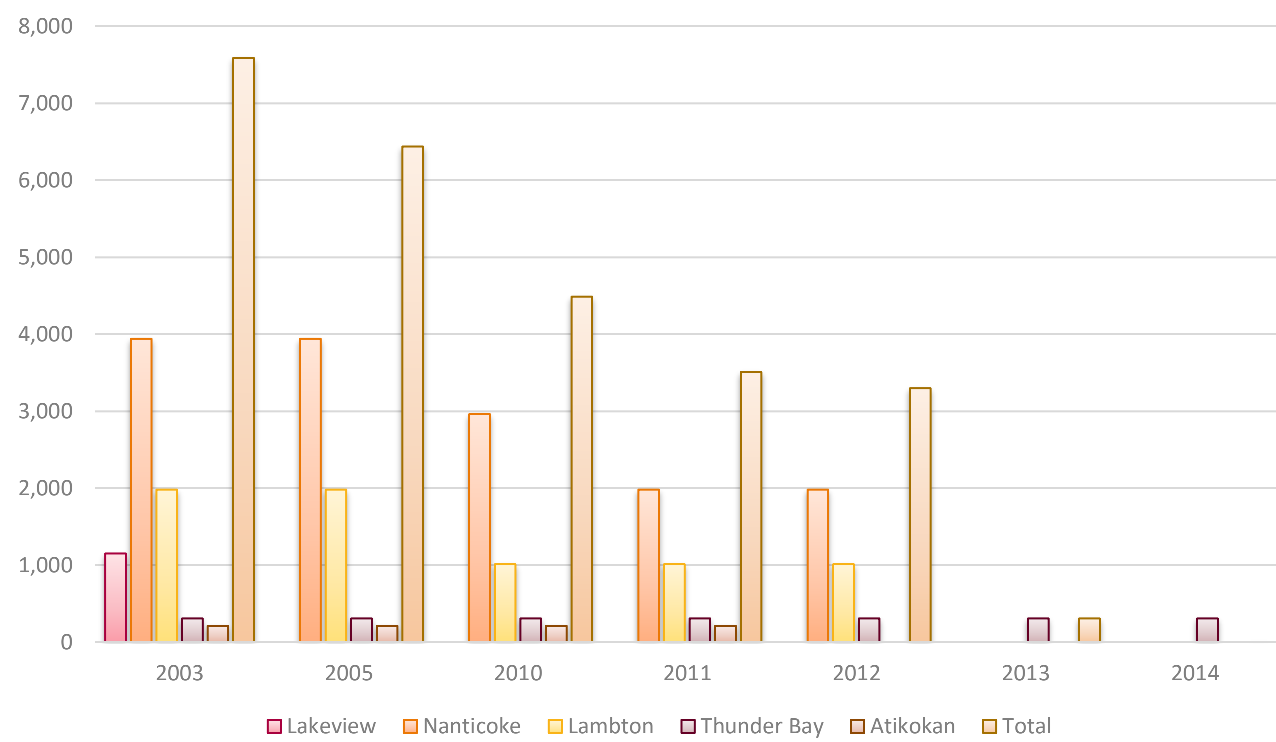
[9] https://www.cbc.ca/news/canada/toronto/electricity-ontario-1.3538157

The Coal-Fired Generation Phaseout and Replacement with Gas-Fired Generation

Ontario didn't just increase the installed generation capacity while demand was declining, it also fundamentally changed the nature of the generating fleet, beginning with the closure of all coal-fired generation.

In 2003, the province committed to close its five coal-fired generators, which together accounted for more than 7,500 MW of installed generation capacity and accounted for nearly 25% of its supply mix. The last coal-fired generator officially closed in 2014.

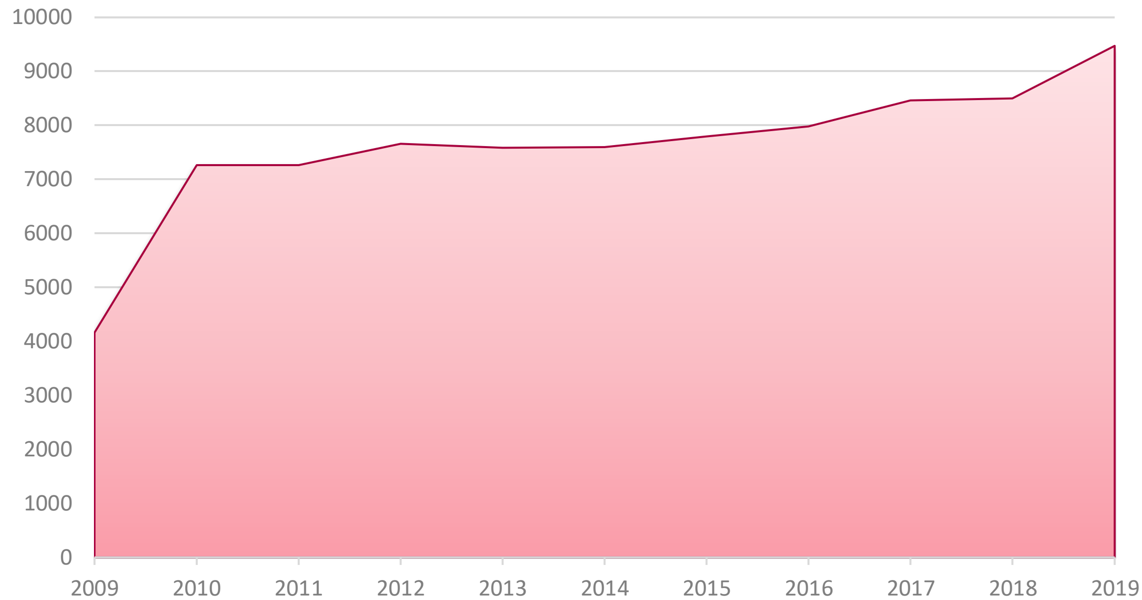
Figure 14 - Installed Ontario Coal-Fired Generation Capacity (MW)



In order to maintain the reliability of the grid and meet forecasted demand growth, the installed coal-fired generation was largely replaced with new gas-fired generation, which have lower carbon emissions yet continue to provide flexibility to the wholesale market by helping to manage short-term fluctuations on the grid. Partly as a result of the coal-fired generation phaseout, Ontario currently has nearly 10,000 MW of gas-fired generation, accounting for more than 25% of grid-connected generation capacity – nearly all of it under contracts with the IESO.

Between 2004 and 2019, nearly 7,100 MW of grid-connected, large-scale gas-fired generation was added to the system – excluding the 2,000 MW Lennox facility owned and operated by OPG. All of this generation capacity is grid-connected and signed to contracts. A number of smaller, combined heat and power (CHP) gas-fired generators were also added to the system. In total, the IESO has contracted nearly 9,500 MW of gas-fired generation. As a result of the province's decade long capacity surplus, the capacity factor – the amount of energy output actually generated compared to its physical capabilities – of these facilities is often very low. Gas-fired generators currently account for more than 25% of installed generation capacity, but only 6% of total energy output.

Figure 15 - Contracted Gas-Fired Generation Capacity (MW)

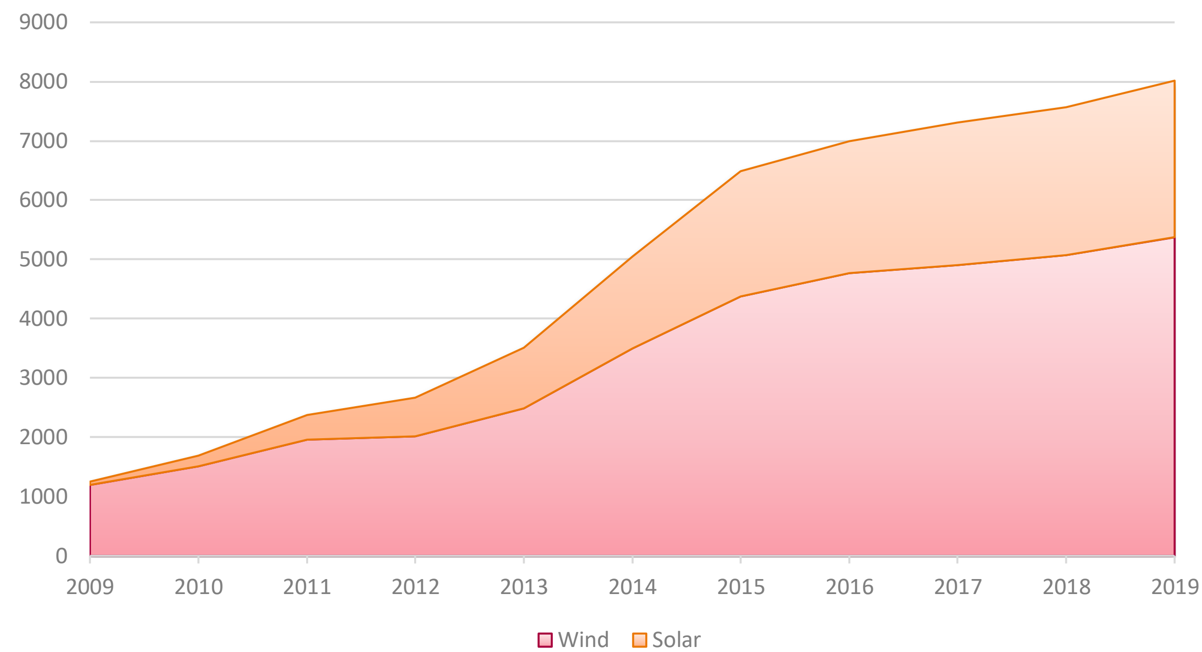


The Integration of the Renewable Generation

At the same time that the province moved ahead with its phaseout of all coal-fired generation, it also began developing and integrating renewable generation into the province's grid – including wind, solar, hydroelectric, and bio-fueled generation.

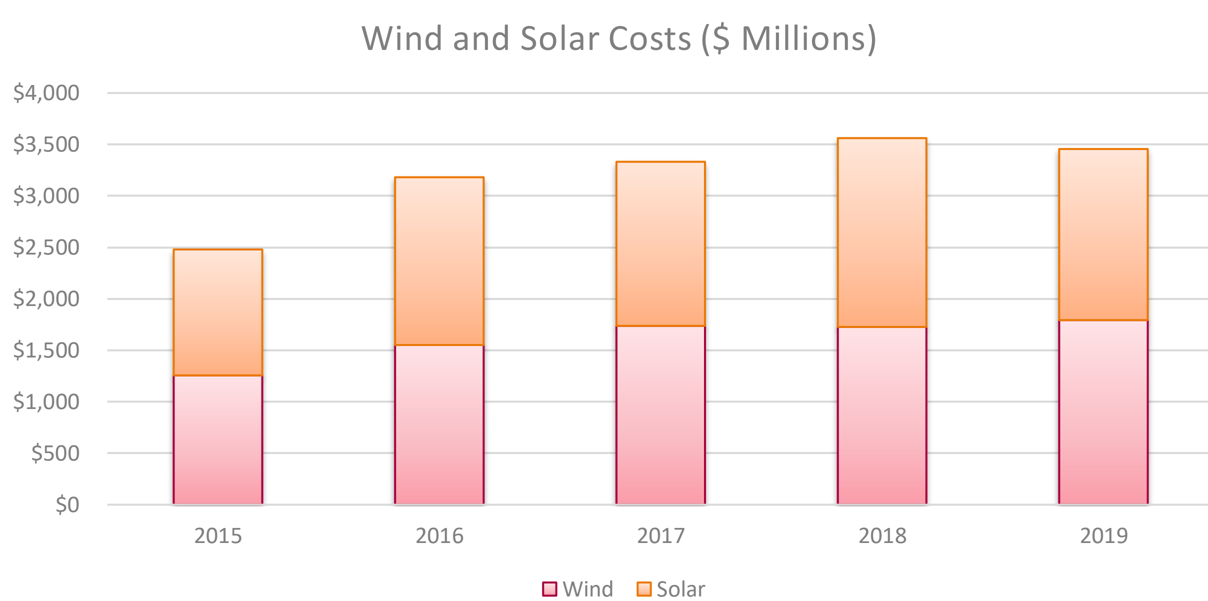
The introduction of renewable generation began in 2004, but increased dramatically with the *Green Energy and Green Economy Act* (2009) that mandated administration of a Feed-in Tariff (FIT) program to contract for renewable generation projects. In Ontario, the initial contract prices under the FIT program were set at or above spot market prices in order to attract investment. The development and integration of wind and solar generators, in particular, has increased significantly over the last decade.

Figure 16- Contracted Wind and Solar Generation Capacity (MW)



The costs associated with renewable generation have grown in tandem with their integration into the supply mix. Currently, the total cost of wind, solar, and bio-fueled generation is $3.5 billion, which is roughly 27% of the GA.

Figure 17 - Wind and Solar Generation Costs ($ millions)



The tandem policy drivers of closing down the province's coal-fired generation and the large-scale development and integration of renewable generation signed to contracts at above market prices resulted in an overall increase in fixed system costs. While the broader social aims of these two policies were perhaps merited, they had an undeniable impact on the overall cost of electricity in Ontario.