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DRAFT

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The Economic Cost of Electricity Generation in Ontario

INTRODUCTION

This report brings an economic perspective to the analysis of electricity generation costs and prices in Ontario. Generation accounts for approximately two-thirds of Ontario's total electricity system costs, making consumers' electricity bills particularly sensitive to changes in generation policies and the cost of ensuring that sufficient generation capacity is available to meet demand. In Ontario, the wholesale price of electricity generation has declined since 2006, yet regulated rates for household consumers have almost doubled, creating some confusion over the reasons why bills have increased. While a comprehensive analysis of electricity system costs and consumer bills is outside the scope here, this report provides an economic cost analysis of the generation component of electricity bills, which can reconcile these seemingly contradictory trends. An important insight, which comes from the experiences of jurisdictions that have deregulated their power generation sectors, is that wholesale generation markets are often distorted by the effects of administrative restrictions on market operations and by parallel long-term contracting policies, undermining the signals that market prices would otherwise provide for efficient generation production, investment, and consumption decisions. In such markets, wholesale market prices are shaped in part by strategic bidding behaviour of generators, and need not accurately reflect underlying average or marginal costs of generation. Consequently, a complete account of the cost of generation, and its pricing, requires a broad analysis that incorporates a range of generation sector policies.

WHOLESALE ELECTRICITY MARKETS AND INVESTMENT IN GENERATION CAPACITY

In competitive markets with many buyers and sellers, homogenous products and firms, and unrestricted exit and entry, market prices send crucial signals to firms and consumers, and help balance demand with supply. Importantly, these conditions create a close relationship between prices and costs since competitive pressures push prices to the marginal cost of production. External shocks to demand or supply that shift prices will cause firms to enter or exit the market, moving prices to long-run average cost levels over time. For example, an increase in demand that increases prices will encourage new firms to enter the market, subsequently exerting downward pressure on prices. In the long-run, market prices enable firms to recover both fixed and variable costs, and to earn a normal rate of return on capital invested. Hence, in competitive markets, prices are an indicator of the long-run cost of producing goods and services.

Wholesale electricity generation markets, however, generally do not conform to the ideal of an unfettered competitive market (Borenstein, 2016). The distinctive characteristics of electricity markets are many and well-known. Electricity is not storable in large quantities so production must match extant demand. Renewable power sources are intermittent, necessitating complementary investment in dispatchable generation capacity that may have low utilization rates. Transmission and distribution are subject to congestion, creating conditions for oligopoly or even monopoly pricing. Demand is highly price-inelastic in the short-term for many consumers, implying consumers are willing to pay very high prices for electricity. Variable costs of production are small relative to high fixed costs, especially for renewable power sources, meaning variable costs can be significantly lower than average costs. Renewable power, which governments have encouraged for environmental reasons, often has higher average unit costs than fossil fuels, requiring additional policy instruments to support private investment. Entry by new generators is highly regulated, and it can take many years for permitting and construction to be completed, leading to extended periods of under- or over-supply of capacity. Under such conditions, wholesale generation market prices can easily diverge from average costs for long durations, creating an uncertain investment environment for generators. Two risks are particularly germane:

First, small shocks to demand or supply can lead to rapid escalation in wholesale market prices given short-run price-inelasticity of demand and also of supply. For instance, in Ontario during September 2002, even though the average price over the month was $83/MWh, it peaked at $1028/MWh, more than twelve times the average. Price spikes reflect scarcity and are a feature, not a flaw, of a well-functioning market. However, dramatic price spikes often create consumer pressure on governments to intervene and to reduce volatility by implementing caps. In Alberta, the government capped wholesale market prices at $1000/MWh (Brown and Olmstead, forthcoming). Ontario's maximum wholesale market price is set at $2000/MWh.

One consequence of such intervention is that it can create a "missing money problem" for generators. As one electricity market expert noted, "The missing money problem arises when occasional market price increases are limited by administrative actions such as price caps. By preventing prices from reaching high levels during times of relative scarcity, these administrative actions reduce the payments that could be applied towards the fixed operating costs of existing generation plants and the investment costs of new plants" (Hogan, 2005, pg.1). By limiting the opportunities for generators to recover fixed costs, price caps can act as a disincentive for generators to invest in new capacity.

A second risk for generators is that if markets develop excess generation capacity, wholesale prices will be pushed down towards variable costs, preventing generators from recovering fixed investment costs, which can be large given the capital-intensive nature of electricity production (Borenstein, 2002). Anticipating that future market conditions could change, generators may be unwilling to invest in new capacity—even if current levels are not fully sufficient to meet demand—when costs can only be recouped through wholesale market revenues. Such risks are magnified in institutional environments where government entities can rapidly implement sweeping regulation or policy changes, as in parliamentary systems with majority party control.

For these and other reasons, wholesale electricity market prices often do not send accurate signals to producers or consumers regarding efficient production and consumption behaviour, nor need they create the competitive incentives for generators to make sufficient long term investments in capacity for reliable supply within a jurisdiction, especially in generation technologies that have high average costs relative to variable costs (e.g. renewable fuels) or that have very long payback periods (e.g. nuclear power). This means that governments, even in deregulated markets, must rely on complimentary policy mechanisms to enable generators to recover their fixed costs of electricity generation and to remain in the market. Long-run power purchase contracting, which effectively mimics average cost pricing, has been a common approach in many jurisdictions, as have been separate capacity markets (Biggar and Hesamzadeh, 2014). Invariably, however, additional policy instruments do not operate independently but have spillover effects, introducing further complexities and distortions into the operation of wholesale markets.

ONTARIO'S GENERATION SECTOR AND WHOLESALE MARKET

Background

Over the last half century, several structural shifts have fundamentally changed the nature and cost profile of Ontario's electricity generation sector. Major nuclear generating capacity was brought online during the 1960s to 1980s, transforming baseload generation in the province. Construction costs proved to be significantly greater than expected, however, leading to rate increases of more than 30% in the early 1990s, shortly followed by a rate-freeze imposed by a new (NDP) government in 1993 (Trebilcock and Hrab, 2005).[1]

The second structural change occurred in the late 1990s and early 2000s when the province, in concert with many other jurisdictions that were seeking greater electricity sector efficiencies, experimented with market deregulation and restructuring. In May 2002, the Conservative government launched a competitive wholesale electricity market and a short-lived competitive retail market. Hot summer temperatures combined with a shortage of generation capacity triggered wholesale price spikes and rapid increases in consumer bills (Trebilcock and Hrab, 2005, pg. 126).[2] Yielding to public pressure to reduce 'rate shock', the government quickly reversed course, closing the retail market in November 2002, implementing a rate freeze, and shelving plans for privatization and restructuring of generation assets. The government retained the wholesale market with the expectation that it would encourage private investment in new generation capacity.

The third structural shift began in the mid-2000s under a newly-elected Liberal government that initiated a significant rebalancing of the supply mix, notably reducing the share of coal generation while phasing in renewable sources such as wind and solar. To achieve this, the government created the Ontario Power Authority (OPA) to enter into long-term power purchase contracts with generators, operating under the direction of the Minister of Energy. To expedite the government's policies and to avoid repeating the 2002 summer-time supply shortages, the government implemented a series of long-term contracting programs for specific types of generation technologies, including through competitive procurements, standard offer or feed-in tariff programs, and bilateral negotiations with private generators. Under each of these mechanisms the government guaranteed to buy power at a fixed unit rate over specified time period, commonly 20 years (though in some cases, for instance natural gas generation, contracts provided fixed monthly payments for capacity). Long-term contracts reduce the uncertainty and risk associated with providing a reliable supply of electricity, but they shift risks from firms to ratepayers.

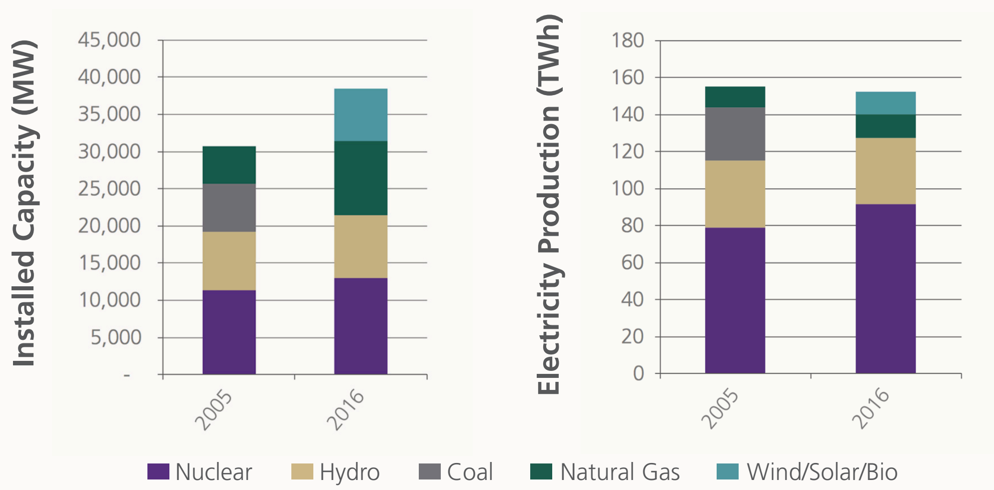
Since 2005, the OPA (now the IESO) has contracted for approximately 6,000MW of wind capacity and more than 2,600MW of solar capacity (IESO, 2016a). The province officially eliminated coal from its generation mix in April 2014. In total, the IESO has contracted for more than 27,000MW of energy. This matches the province's highest ever peak demand, which occurred in August 2006, and is in excess of peak demand over the past five years (IESO, 2017a). Ontario Power Generation (OPG) controls additional significant nuclear and hydroelectric capacity.

[1] The rate freeze remained in place until the Government launched the competitive retail market in 2002.

[2] Hourly electricity prices spiked to $1.03/kWh during hour 14 on September 3, 2002 (Trebilcock and Hrab, 2005).

Figure 1 presents the share of generating capacity, output and OPA-contracted capacity by fuel type in 2016. Nuclear comprises slightly more than one-third of capacity, but produced nearly two-thirds of Ontario's electricity in 2016. Natural gas generators have the second most capacity but produced roughly the same output as wind and less than hydroelectric generators. The largest share of contracted generation is natural gas, but this excludes assets owned by OPG. Non-hydro renewables accounted for a relatively small share of Ontario's capacity (18%) and output (8%) in 2016.

Figure 1: Installed Capacity and Electricity Production by Fuel Type, 2005 and 2016



Source: IESO Supply Mix data and Ontario Power Authority 2005 Supply Mix Advice.

Investment in new generation capacity since 2005 has been supported mainly by long-term contracts with private generators that specify a fixed purchase price for energy produced (e.g. $135/MWh for wind power under the FIT program), though they are structured as 'contracts for differences', which provide two related components of revenue for the generators. The first component consists of the prevailing wholesale market price for power, referred to as the 'Hourly Ontario Energy Price' (HOEP). Since wholesale prices may be less than the contracted rate, the second component is the difference between the agreed contract rate and the wholesale price, referred to as the 'Global Adjustment'. In total, the Global Adjustment and Hourly Ontario Energy Price sum to the compensation needed to cover the contracted fixed rates paid to generators. The Global Adjustment exists because, in general, market-based revenues are insufficient to cover both variable and fixed costs of generating electricity. The combination of the Global Adjustment and the Hourly Ontario Energy Price effectively represent average cost pricing, enabling generators to recover their total costs.

Wholesale Electricity Market

Ontario's wholesale electricity market operates primarily as a mechanism for dispatching generation units in order to ensure a reliable and continuous supply of electricity. The hourly market price is determined by bids submitted in advance by generators that specify the amount of power they are willing to provide and the offer price. The IESO sets the HOEP based on the bid of the marginal generating unit and purchases power from all generators at this price. Generators that submit bids greater than the HOEP are not dispatched and do not receive wholesale market revenues. While in theory this approach can yield low cost, efficient power generation, in practice generator bids often do not reflect true costs of production.

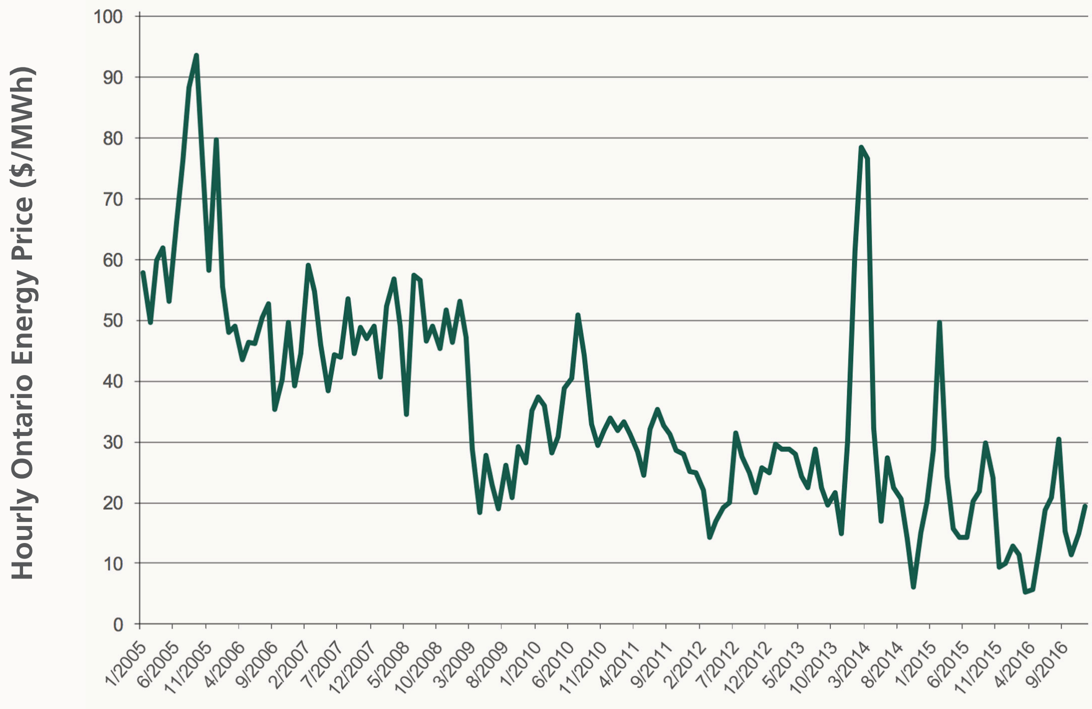
A simple example illustrates this point. Renewable generators such as wind and solar have marginal costs equal to zero. When the wind blows, a wind turbine generates power at essentially no additional cost. In September 2013, however, the IESO implemented new rules regarding the dispatch of renewable resources. The IESO established floor prices for transmission-connected wind and solar generation offers at -$10 per MWh for the first 90% of capacity (subsequently increased to -$3 per MWh) and -$15/MWh for the remaining 10% (Navigant, 2014b). This price floor was enacted because wind and solar generators were bidding into the energy market at prices equal to -$2000 per MWh. Notionally, a bid of -$2000 per MWh suggests that wind generators are willing to pay the operator $2000 per MWh dispatched, an unlikely proposition. In reality, wind generators know that they are guaranteed to receive their contracted, fixed rate per MW and want to ensure their power is dispatched. Similarly, nuclear generators have an offer floor of -$5 per MWh to limit strategic bidding behaviour. Between 2009 and 2014, the HOEP was negative for almost 2000 hours (equivalent to 83 days).[4] These examples illustrate that generators are not necessarily bidding their true production cost, but instead are adjusting their bids in accordance with the terms of their fixed price contracts.[5] In this sense, the impact of long-term purchase contracts is to distort the wholesale market price, separating it from economic cost fundamentals.

Since 2005 there has been a declining trend in the hourly energy price on the wholesale market, as illustrated by Figure 2. Contributing factors include falling natural gas prices, lower demand within the economy for electricity, and expansion of generation capacity with low to zero marginal costs such as wind and hydro. In the eight year period 2009 to 2016, the hourly energy price has averaged $28/MWh, significantly below the average total cost of virtually any type of generation technology.

[4] Annual Report of the Office of the Auditor General of Ontario, 2015, page 216

[5] Harvey (2013, pages1-2) states that the hourly Ontario energy price "does not reflect the actual cost of meeting load … and therefore does not send an accurate signal for longer term decisions, such as the entry or exit of generation or of particular types of generation, for increases or decreases in power consumption, or for generators and dispatchable loads." Moreover, no entity in the province purchases electricity via the wholesale market (Alpin, 2017).

Figure 2: Hourly Ontario Energy Price



THE COST OF GENERATION IN ONTARIO

The cost of contracted generation, which accounts for the majority of capacity in the province, is approximated by the sum of the wholesale market hourly spot price and the Global Adjustment amount, which acts as a full cost recovery mechanism (MacDougall, 2012).[6 7] The combination of the two components is equivalent to average cost pricing as it enables contracted generators to recover both fixed and variable costs over the duration of the contracts.

The formal description of the Global Adjustment is outlined in Ontario Regulation 429/04.[8] Officially, it is a payment variance that reconciles the difference between the earned revenues in the wholesale market and the rates established via contract. The relationship between the hourly Ontario energy price and the Global Adjustment may be characterized as a seesaw. When the hourly Ontario energy price goes up, the Global Adjustment goes down; and when the hourly Ontario energy price decreases, the Global Adjustment increases. This relationship is automatic and mechanical. Importantly, this seesaw relationship implies that neither the wholesale price nor

[6] Non-contracted generation includes Ontario Power Generation's nuclear and hydro electricity assets which have rates established through cost-of-service regulation.

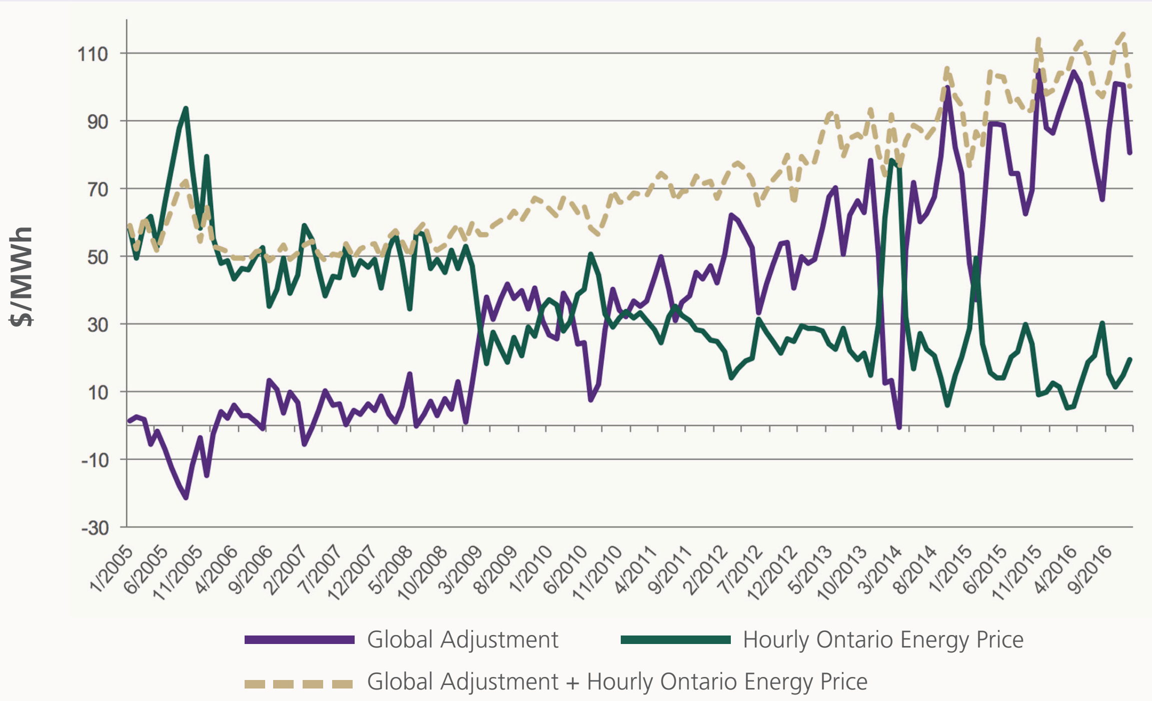
[7] The global adjustment charge also encompasses charges for several other programs such as conservation and demand management though these are relatively small amounts relative to payments for generation.

[8] Section 1(1) of 429/04 precisely presents the calculation of the Global Adjustment.

the Global Adjustment provide an accurate 'market signal' to consumers or generators. Further, it is incorrect to interpret the Global Adjustment as an overpayment or 'above-market' payment for generation, as some commentators have claimed, since the wholesale price is not a true market price as would be observed in normal competitive markets. The appropriate counterfactual for Ontario prices is less obvious than it might seem at first inspection and needs to be formulated as the inclusive price that covers both variable and fixed costs in the absence of policy intervention.

Figure 3 illustrates the hourly Ontario energy price and the unit Global Adjustment amount from 2005 to 2016. The hourly Ontario energy price is calculated as an hourly average of 5-minute dispatch prices, which are determined in the real-time market. The Global Adjustment is calculated monthly, and is based technically on the difference between the hourly Ontario energy price and (i) IESO's contracts with generators, (ii) contracted rates administered by the Ontario Electricity Financial Corporation, and (iii) OPG's regulated nuclear and hydro generation rates (IESO, 2016b). The seesaw or inverse relationship between the Global Adjustment and hourly wholesale energy price is immediately obvious in the figure.[9] While the hourly price has steadily declined since 2005, albeit with natural monthly variation, the Global Adjustment has increased over the same period, mirroring monthly movements in the hourly price.

Figure 3: Hourly Ontario Energy Price and Global Adjustment, 2005–2016

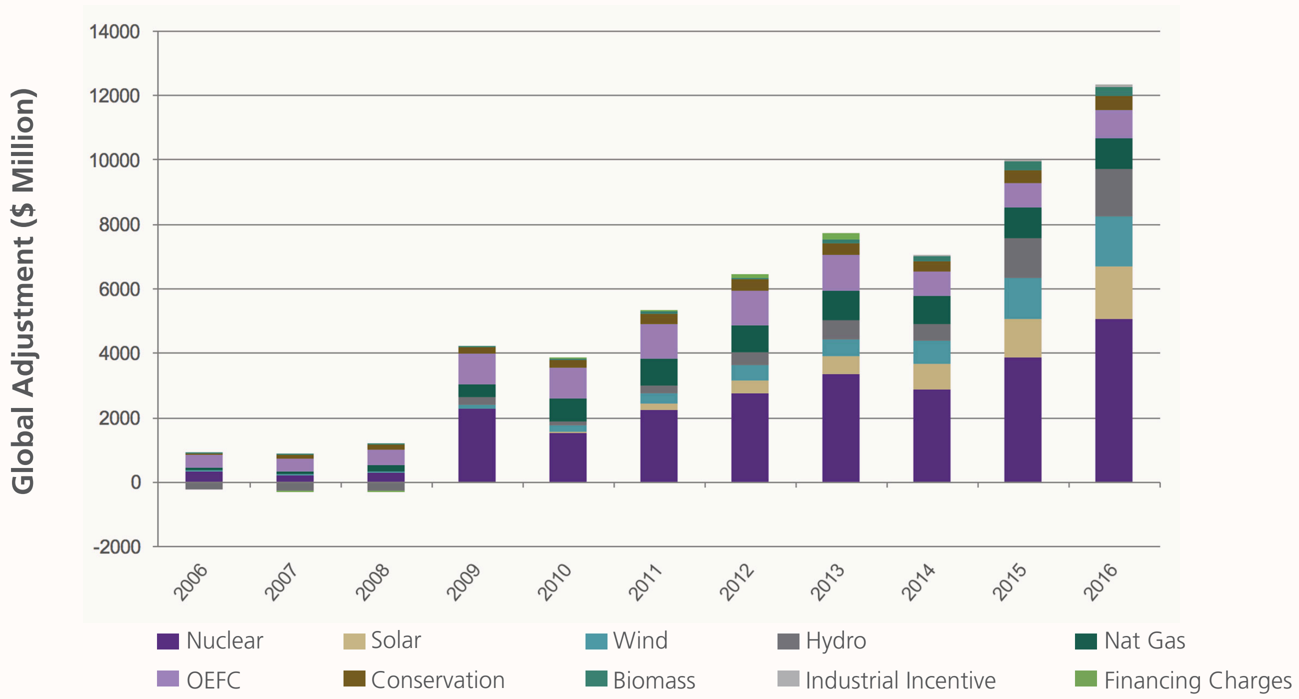


Source: IESO

[9] The relationship is not a perfect one-for-one because the Global Adjustment is a true payment variance and hence includes the costs of conservation programs and financing charges. Also because the Global Adjustment shows up in customers' biannual rate plans, the Global Adjustment in conjunction with the hourly Ontario energy price, induces a small demand response.

Decomposing the Global Adjustment into its components provides some insight into the share of costs attributable to different generation fuels as shown in Figure 4. It does not provide an accurate picture of total generation costs by fuel type since it does not include costs recovered through wholesale market revenues, though these were a minor share in 2016. The overall Global Adjustment amount was $12.3 billion in 2016. Nuclear accounted for the single largest share of Global Adjustment costs at 41%. Solar and wind power each accounted for 13%, hydro electric power 12%, and natural gas 8%. Other components summed to 13%.

Figure 4: Global Adjustment by Component, 2006–2016



Source: IESO

SOURCES OF RATE INCREASES

Rates paid for electricity in Ontario have increased despite a steadily decreasing wholesale market electricity price due to corresponding increases in the Global Adjustment as previously described. While a formal analysis of the sources of these rate increases is beyond the scope of this report, it is valuable to briefly review some of the underlying reasons for these increases. Much of the increase in electricity rates is due to a combination of structural changes to Ontario's electricity system and investments to upgrade and refurbish aging transmission, generation, and distribution assets.

The average unit cost of generation (per MWh) is represented by the dashed line in Figure 3, the sum of the hourly wholesale price and Global Adjustment. From 2006 until 2009, the average cost was relatively stable, remaining between $50 and $60/MWh. Since 2009 there has been a continuous upward trend in the average cost of generation, reaching more than $110/MWh by late 2016. A number of factors have contributed to this trend:

1. *Phase out of coal-fired generation.* Between 2005 and 2014 Ontario gradually phased out all coal-fired plants, which provided 25% of power generation in the province at a relatively low unit cost (approximately $48/MWh). The coal fleet was reaching the end of its productive life, and new capital investment required to replace it would have increased system-wide costs of generation, and hence rates, regardless of the replacement type of generation fuel. For example, the refurbishment of Bruce Power nuclear units, which provide base load power, yields power at a contracted rate of $66/MWh. Offsetting higher costs, however, are health and environmental benefits from switching from coal to less emission-intensive fuel sources.

2. *Increasing share of renewable fuels.* The *Green Energy and Green Economy Act of 2009*, and initiatives such as the Renewable Energy Standard Offer program launched in 2006, have led to the development of a significant amount of wind, solar, and bio-energy capacity, supported by fixed feed-in tariffs guaranteed for 20 years. Between 2005 and 2015, the province added approximately 7 GW of new wind, solar and bio-energy capacity, accounting for 18% of installed capacity in 2015. The rates paid for renewable power are much greater than rates paid for other fuel sources, for instance ranging from $135/MWh for on-shore wind to $802/MWh for small scale rooftop solar PV under the 2010 FIT pricing schedule. Power purchase prices for new solar capacity have since declined as technology costs have fallen steeply, but remain above levelized unit costs for natural gas and nuclear power. In addition to higher direct costs, the expansion of renewable generation capacity has required complementary investment in transmission and distribution sector upgrading, an indirect cost implication for the electricity system.

   The Ontario Energy Board provides annual estimates of average total generation costs by fuel type based on payments to generators and output. The OEB's 2016-17 estimates illustrate the higher average cost of wind, solar and bio-energy relative to nuclear and hydro (see Table 1).

Table 1: Average Costs of Generation per MWh by Fuel Type

Generation Fuel	Average Unit Cost ($/MWh)
Nuclear	6.6
Hydro	5.8
Natural Gas	17.3
Wind	14.0
Solar	48.0
Bio-Energy	13.1

Source: Ontario Energy Board Regulated Price Plan Report, November 2016 to October 2017. Hydro excludes NUGs and OPG non-prescribed generation. Gas includes Lennox, NUGs and OPG bio-energy facilities.

3. *Overall growth in installed generation capacity.* One of the consequences of expanding renewable power generation, which is intermittent, is the need to invest in complementary natural gas or other dispatchable capacity that can operate during periods when renewable power is not available. Ontario added 5 GW of natural gas capacity between 2005 and 2015, much of which provides peak and mid-peak power. The overall amount of installed capacity in the province has increased significantly over the last decade. In 2016, installed capacity was approximately 39 GW—a 25% increase from 31 GW in 2005. While capacity has grown, however, overall annual domestic demand for grid power has declined, due to a combination of pricing effects, weaker economic growth, enhanced conservation efforts, and expansion of distributed energy resources. According to IESO data, grid demand declined by 10% from 2006 to 2015. Annual peak grid demand has also fallen sharply, from an all time high of 27 MW

in August 2006 to 22.5 MW in 2015. While forecasting long-term electricity demand is notoriously difficult, the province has invested in new generation capacity that has proved to be considerably in excess of needs, contributing to higher system-wide costs and consumer bills.

4. *Increasing electricity exports and associated Global Adjustment costs.* Annual electricity exports have more than doubled from 10 TWh in 2005 to approximately 22 TWh in 2015, representing 14% of total generator output of 154 TWh. The Global Adjustment is not levied on electricity exports, and power is sold at the wholesale market price, which averaged $24/MWh in 2015. Under the terms of power purchase contracts, however, contracted generators must be compensated for the full rate for their power, which in all cases is more than the average wholesale market price in 2015 (e.g. $135/MWh for wind, $66/MWh for Bruce nuclear power). The difference between the contracted rate and the wholesale market price is incorporated into the Global Adjustment amount paid by Ontario rate payers. Hence, as exports increase so do domestic rates.

OPTIONS FOR GENERATION MARKET AND POLICY REFORM

The rapid pace of contracting for new generation capacity since 2005 has contributed to a corresponding escalation in consumers' electricity bills. Over the last decade, regulated electricity rates for residential consumers have almost doubled, creating a degree of 'rate shock' and leading to calls for generation market reform. This section examines first a policy proposal that can ameliorate rate shock, and secondly structural reforms in the wholesale market that may improve long-run efficiency in generation investment.

Smoothing Contracted Generation Costs

While the government has taken some heat for rising bills, there is a potential policy solution that is economically rational, equitable to consumers, and relatively simple to implement. The government could smooth the costs of contracted generation capacity – which account for more than half of electricity system costs – over a longer period of time than is currently planned, reducing consumer bills in the short to medium term in return for slightly higher bills in the long term. This is akin to household mortgage refinancing that lowers monthly payments by extending the term.

The economic rationale for such a smoothing policy is that the useful productive lives of contracted generation assets – payments which constitute the majority of global adjustment charges – are in many cases longer than the durations of the contracts. For instance, wind power RESOP, FIT and LRP contracts are structured for 20 years, even though wind turbines and equipment may be expected to operate for 30 years or longer, assuming periodic maintenance and refurbishment is undertaken. Similarly, natural gas generation contracts are generally for 20 year periods, though in the U.S. gas plants have often been retired after 40 years. Under 20 year contracts generator capital costs are amortized too quickly relative to the useful life, leading to higher annual capital charges than would be the case if the amortization period was extended to the full expected life span. Charges to consumers for contracted generation could hence in principle be reduced by stretching capital amortization periods to match the expected productive lives of the assets. In this way, the costs of generation charged on consumer bills would more closely reflect the true economic costs of the assets.

There are three possible ways to accomplish this in Ontario, recognizing that many new contracts with generators have already been agreed over the last 12 years.

1. *Create option for existing generators to bid for new long-term contracts*
   First, the government could offer generators with existing contracts the opportunity to bid for new contracts that would supersede their current contracts, stipulating that (a) the time horizon for a new contract must extend beyond the current one, and (b) the new purchase price for electricity for the duration of the new contract must be lower than the current contracted rate. If the generator and government reach agreement on new terms the new contract would replace the original one. Otherwise, the original contract would remain in force.

   From the generator's perspective, this provides an opportunity to lengthen the time horizon of financial returns on their investment, and to increase the extant expected net present value of the project. It also pre-empts a potentially challenging renegotiation with the government at the end of the original contract when the assets still have productive capabilities but have been fully amortized.

   From the government's perspective, generation costs would be smoothed over a longer period of time as determined by individual generators on a case-by-case basis, lowering average electricity bills in the short to medium term. Importantly, since the government need not accept all new generator contract proposals (due to the possibility that future demand for electricity will decrease), this process would create bidding competition between generators—competitive pressures that could lead to lower average power purchase rates in new long-term contracts.

2. *Short-term government subsidization of payments to generators*
   An alternative approach for smoothing the amortization of generation costs is for the government to subsidize in the short to medium term a portion of annual contracted payments to generators operating under existing contractual terms, and to reduce consumer bills by the corresponding amount. The subsidy each year would equal the difference in annual amortization currently charged (based on the contract duration) and the annual amortization amount calculated using the productive life of the asset. Interest rates on government debt (which would fund the short-term subsidy) are currently very low (2.4% on Ontario's recent 10-year bond issue), making this a relatively cost-effective strategy.

   In both approaches, the quid pro quo is that consumers would pay more for electricity in the future to reflect the longer amortization period, specifically during the years beyond the end of the original contract and up to the useful life of the generation assets.

3. *Long-term contracting policy*
   In future contracting exercises, the government could invite generators to submit bids that include the proposed contract duration, and evaluate such bids on the basis of contract duration as well as on purchase price and other factors. Providing flexibility on duration would encourage generators to match the contract period to the expected productive life of the asset, resulting in (lower) annual amortization costs that reflect the true economic cost.

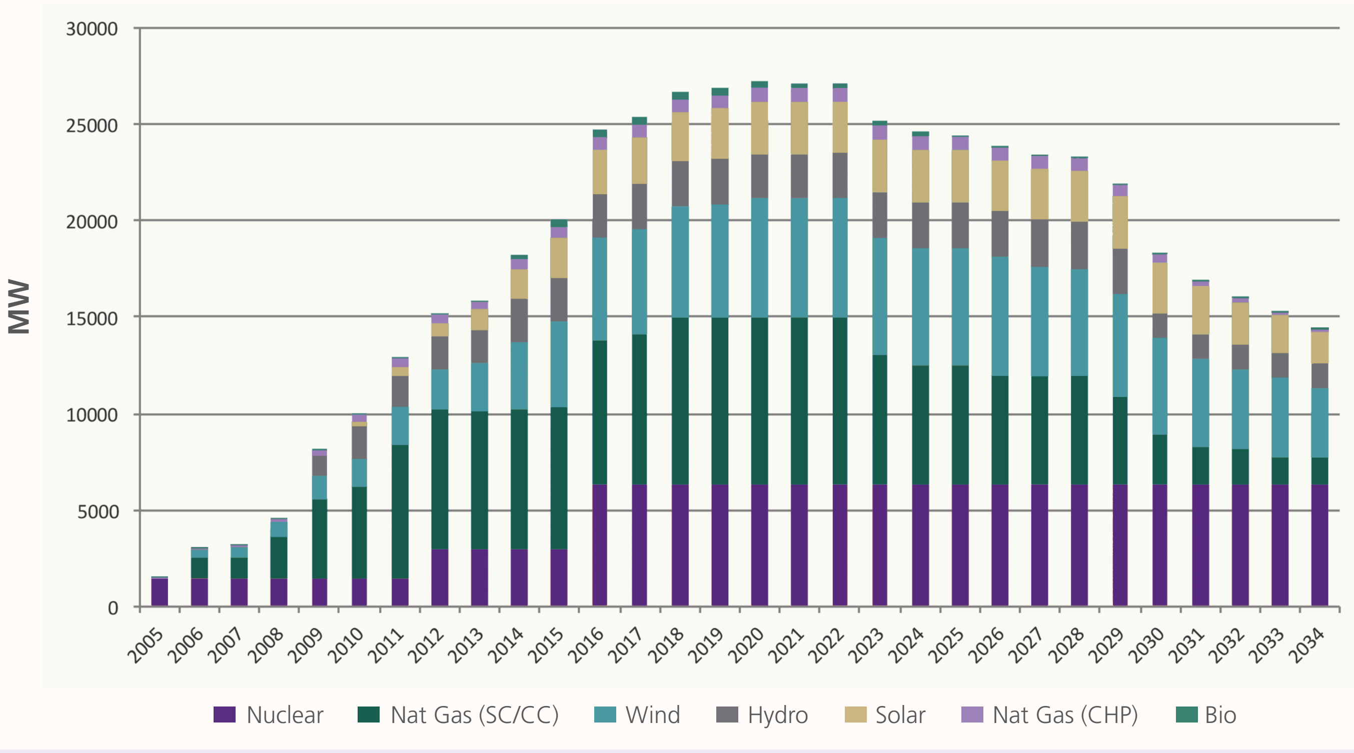
Preliminary Estimate of Impact of Smoothing Contracted Generation Costs

Estimating the potential impact on electricity bills from stretching out generation asset amortization periods requires detailed information on the terms of generator contracts, which are not publicly available. Assumptions based on available Ontario Energy Board (OEB) and IESO data, however, can lead to approximate calculations, albeit with circumscribed confidence in their accuracy.

Since 2004 the Ontario government has contracted for a significant amount of new generation capacity through competitive procurement exercises, bilateral negotiations, and feed-in tariff programs. By 2006, approximately 3,000MW of newly contracted capacity was operating; by the end of 2016, almost 25,000MW of contracted nuclear, natural gas, hydro, wind, solar, and bio-energy capacity was in place, representing a dramatic increase in procurement over a 10-year period. New procurement is expected to slow down in the coming years, reaching a peak of 27,000 MW accumulated contract capacity in 2020.

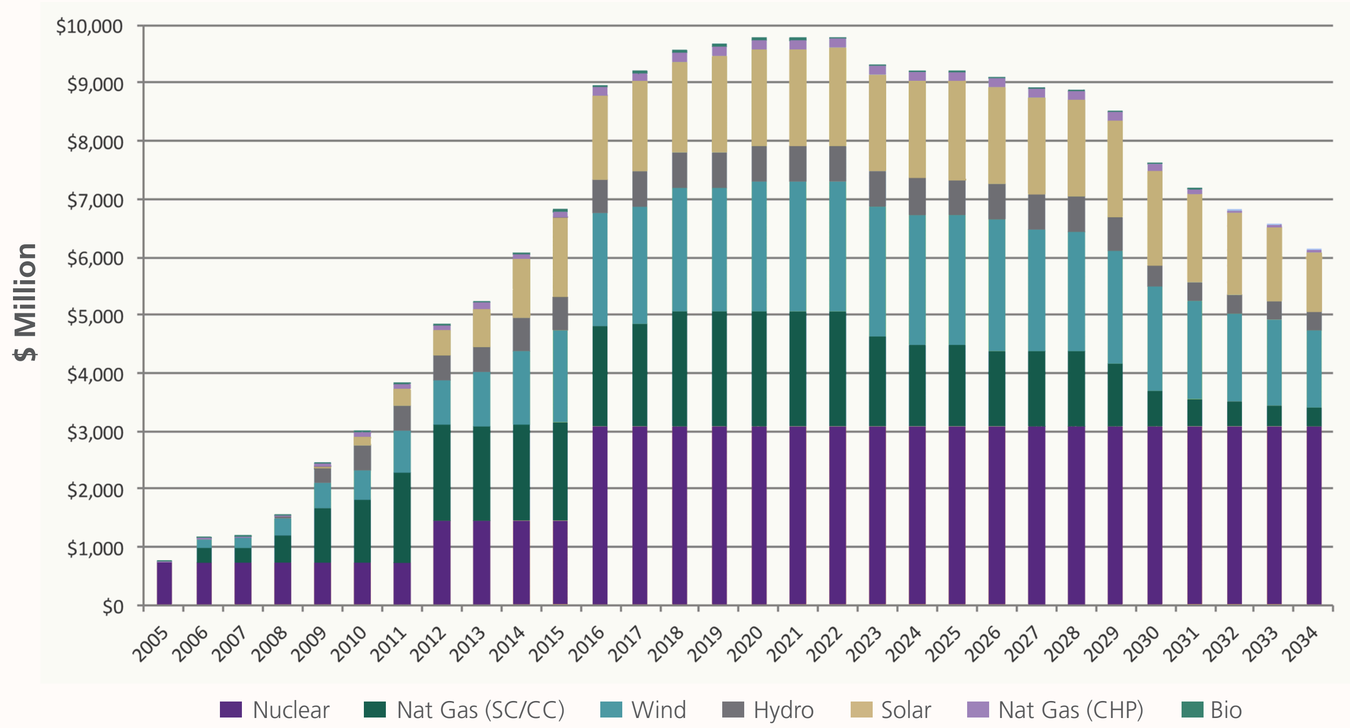
Figure 5 shows the amount of accumulated contracted capacity for each fuel type for the 30-year period from 2005 to 2034. There has been a significant increase in contracted natural gas generation (representing 33% of total contracted capacity in 2017), as well as in nuclear (25%) and wind (22%). Solar, hydro, bio-energy and other fuels account for the remaining 20% of the 2017 total. OEB data on the average unit cost of electricity by

Figure 5: Contracted Generation Capacity by Fuel Type, 2005–2034 (MW)



Source: IESO Progress Report on Contracted Electricity Supply, Third Quarter 2016. 'Other' fuel category omitted for simplicity.

Figure 6: Estimated Cost of Contracted Generation, 2005–2034 ($ Million)



Source: Author estimates. 'Other' fuel category omitted.

fuel type, and IESO data on capacity utilization, leads to approximate estimates of the annual cost of contracted generation capacity.[10] In 2016, payments to contracted generators are estimated to have totaled approximately $9 billion. The estimated costs of contracted generation by fuel type are shown in Figure 6.

An important feature of Figures 5 and 6 is that they chart the contractual duration of capacity, not the useful productive lifespan of the generating assets. According to the IESO, contract terms vary from 5 to 21 years for bio-energy to 31 to 57 years for nuclear units. For natural gas and wind generation, as well as solar, contract periods appear to be somewhat shorter than typical estimates of expected lifespans (see Table 2), though lifespan estimates depend on a multitude of factors such as the specific technology type within a broad category, capacity utilization, and climate conditions. Some caution must thus be used in applying average industry lifespans to the specific case of generators in Ontario.

[10] Average effective power purchase rates per MWh for each fuel type are assumed to be as calculated in the OEB's Regulated Price Plan Report, November 2016. Rates range from $58/MWh for hydroelectric generation to $480 for solar. The same rates are applied each year in the analysis, though it is expected there will be variation in practice due to the changing mix of generation contracts with different purchase terms. Capacity utilization is estimated based on IESO reported installed capacity availability and actual power production for each fuel type in 2016 (http://www.ieso.ca/Pages/Power-Data/Supply.aspx)

Table 2: Durations of Generator Contracts and Expected Asset Lifespans[11]

	IESO contract duration (range)	IESO contract duration (mid point)	IEA duration (2015)[12]	EIA duration (2016)[13]
Natural Gas	10–20	15	30	30
Wind	20	20	25	30
Nuclear	31–57	44	60	
Hydro	20–50	35	80	
Solar	20	20	25	30

Source: IESO Progress Report on Contracted Electricity Supply, Third Quarter 2016.

Nonetheless, estimates of the impact of smoothing generation costs on consumer bills can be calculated under hypothetical scenarios where generator lifespans are assumed to extend to 30 years for natural gas plants and wind farms, and 25 years for solar PV capacity. We do not model contract extensions for nuclear power given the specific nature of CANDU technology, or for hydroelectricity, bio-energy or CHP which are a relatively small share of total contracted capacity costs.

By the end of 2017, contracts for natural gas generation will be an estimated 8 years old on average, implying that 40% of original capital costs will have been amortized (assuming 20 year contracts on average). Amortizing the remaining 60% of capital costs over the next 22 years instead of the originally-planned next 12 years suggests a reduction of up to 45% in annual natural gas generator capital charges may be possible in 2018. For wind power contracts, which will be on average 5 years old in 2017, the equivalent potential reduction in annual capital charges is up to 40% in 2018, and for solar 25%.[14]

In 2018, the total value of reductions in natural gas, wind and solar generation capital charges is estimated at approximately $1.7 billion (see Figure 7, equivalent to 8% of total expected electricity system costs. The amount of the annual reduction declines gradually over time in part due to interest costs on debt for the accumulated subsidy.[15] Additional asset refurbishment expenses in the latter part of the lifespan of generation assets would also reduce the amount of annual savings. After 2030 bills are forecast to be slightly higher for several years than they would have been without smoothing.

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[11] Retirement ages of generation plants also indicate lifespans. In the U.S., natural gas plants have often reached more than 40 years before retiring (Powell, N. America's Ageing Generation Fleet. Power magazine, 28 January 2013

[12] International Energy Agency. 2015. Projected Costs of Generating Electricity.

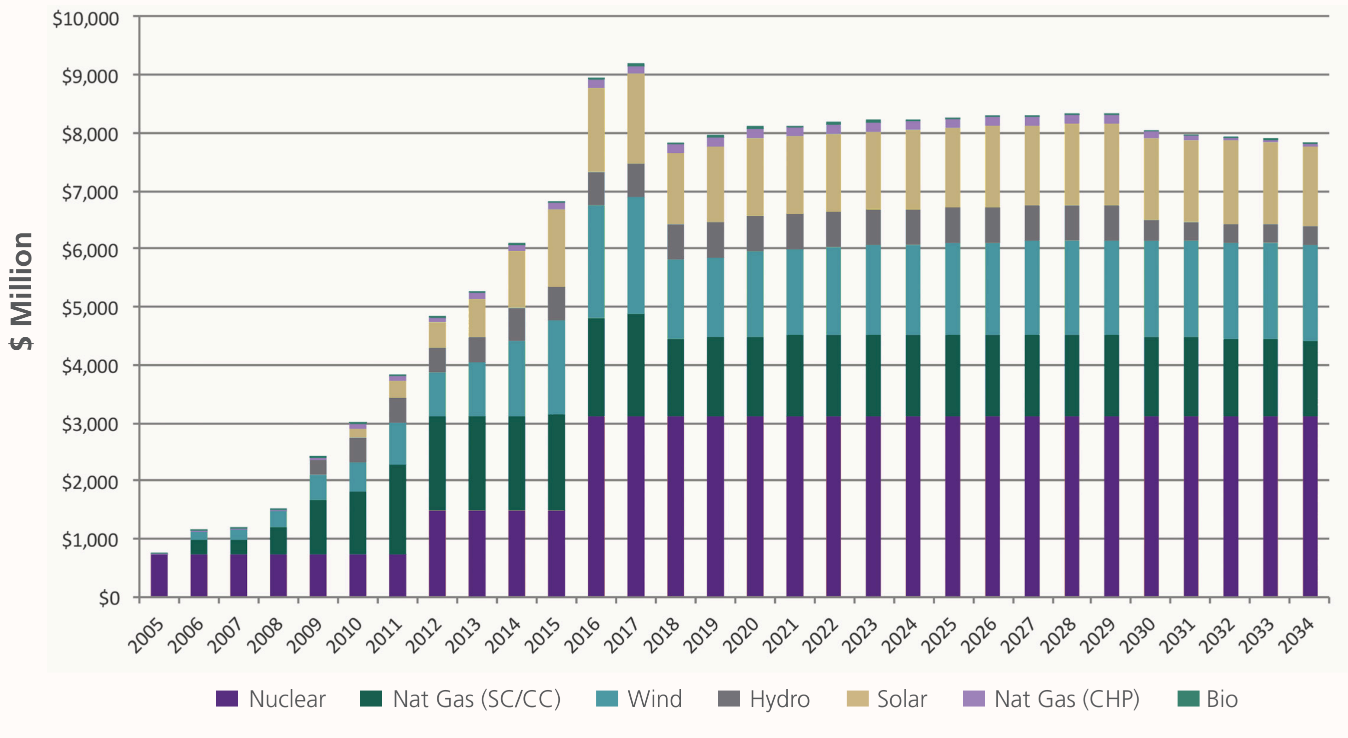
[13] Energy Information Administration. 2016. Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2016. August 2016.

[14] Smoothing is applied only to the assumed capital component of unit generation costs. For wind and solar power which have zero fuel costs, and relatively low variable operation and maintenance costs, it is assumed that 90% of the power purchase rate is accounted for by capital costs. For natural gas capacity, which is assumed to have an average capacity utilization rate of 15% based on IESO data, and an average effective power purchase rate of $173/MWh (based on OEB estimates), the capital cost share is assumed to be 70%. Lower capital cost percentages would reduce the impact on current consumer bills of a smoothing policy.

[15] The interest rate on long-term debt is assumed to be 2.4%, which is the most recent rate on 10-year Ontario government bonds.

These estimates are for option (2) above in which the government finances the smoothing of contracted generator payments over an extended period, leaving original contracts unchanged. The alternative approach outlined in option (1), where generators bid competitively for new long term contracts that supersede existing ones, may deliver similar savings if sufficient numbers of generators participate and submit competitive offers.

Figure 7: Estimated Smoothed Cost of Contracted Generation, 2005-2034 ($ Million)



Source: Author estimates. 'Other' fuel category omitted.

Generation Capacity Markets

Capacity markets have strengths that offer the potential to more efficiently procure future generation for Ontario's electricity market, and anticipated generation refurbishments, retirements and contract expirations provide an opportunity for the province to achieve potential cost savings as well. Cost savings in a capacity market are achieved in two ways. First, competition between generators lowers the cost of procuring capacity through competitive bidding pressures. Second, entry and technology risks are borne by investors and generators instead of by consumers and taxpayers.

Capacity is the availability to generate energy. From the perspective of electricity market design this is separate from energy, which is the physical provision of electricity to the grid. Since demand for electricity fluctuates over the course of a day and across seasons, it is important to have sufficient capacity at all times to ensure reliable power supply. This implies that a significant fraction of generating capacity exists to provide energy for only a small fraction of the hours in a given year (peak demand/load) or only to stand in reserve for contingency purposes (reserve margin).

In traditional regulated utility markets the cost of these resources are recouped at fixed rates. In theory, a perfectly competitive electricity market should be able to incentivize sufficient investment to provide adequate capacity. However, market failures or attributes of the market design can lead to under investment, and incentivizing investment in large infrastructure projects has historically proved to be difficult in deregulated markets. Promoting sufficient investment in generation to cover both peak load and reserve margin needs has often been achieved through either long-term contracts or centralized capacity markets.

A capacity market for electricity generation provides a way to competitively procure capacity in a future period through a forward auction or other mechanisms. This is in contrast to the current method of procuring capacity in Ontario through the use of long-term contracts and centralized procurement. While long-term contracts are successful in attracting investment, they lack flexibility to adapt to changing market conditions and place investment risk on customers. These are the specific weaknesses that centralized capacity markets are designed to address.

The next section describes key attributes and functioning of capacity markets. This is followed by a brief discussion of the anticipated financial benefits of implementing a capacity market in Ontario as well as an overview of the experience of capacity markets in other jurisdictions. Finally, some important caveats and key messages are discussed in considering the implementation of a capacity market in Ontario.

Attributes of Capacity Markets

In a capacity market, generation capacity is typically procured through a flexible, competitive auction process. Firms bid to supply capacity during a specified period when and if needed, subject to non-performance penalties. Suppliers can be broadly defined in capacity markets, including customers who agree to reduce power consumption when requested (demand response), energy efficiency measures, or energy storage. In contrast to confidential private bilateral contracts, the transparency of an auction creates price signals for the electricity market and consumers. The auction design can also be flexible, allowing adjustments to be made to the length of the commitment period and mix of supply technologies.

The ability of a capacity market to incentivize adequate supply resources at low cost depends crucially on a set of market elements. These include 1) the shape of the demand curve, 2) the duration of the forward and commitment periods, 3) the definition of the capacity product, and 4) performance requirements.[16] Each of these attributes and their importance in the functioning of a capacity market are discussed briefly below.

Demand Curve. To determine the amount of capacity to procure, system administrators construct a demand curve for electricity by approximating customer demand for capacity and the prices they are willing to pay. These demand curves are either modelled as vertical or downward-sloping. The shape of the demand curve affects price stability, price signals for new investment, and the amount of capacity procured. Vertical demand curves can lead to price volatility with prices potentially near zero when there is excess supply and at the maximum allowed when there is insufficient supply. This volatility occurs because the quantity procured does not vary with price and thus can be related to capacity additions, which are often larger than current shortfalls to account for future generation needs. Consequently, prices may drop significantly when new generation becomes available. Figure 8 illustrates this “lumpiness” problem, which can be a disincentive to efficient investment in capacity that is moderated by

[16] Measures to mitigate market power are also important in the design of capacity markets.

adopting a downward-sloping demand curve. Since the same level of capacity Q* is always procured, an increase in the supply of generation capacity, represented by the shift from the solid to the dashed supply curve, causes prices to decrease by a large amount.

With a downward sloping demand curve the same shift has a smaller effect on price, however, it implies that the capacity procured through the auction market may be above or below the planning reserve margin (Q*) as shown in Figure 9. This can be largely addressed through the shape of the demand curve by making the curve above the reserve margin steeper to provide less value to capacity above this level. In addition, downward sloping demand curves are sensitive to the assumptions and reference technologies used to estimate it. Typically, the most important among these assumptions is the 'cost of new entry' (CONE) that informs the slope and shape of the curve.[17] Estimation of the CONE value thus has important implications for which technologies will be able to recover their fixed costs in the long run. As a result, the CONE value generally requires updating at regular intervals in order to reflect changing technologies and market conditions.

Figure 8: Increase in Supply of Capacity with Vertical Demand Curve

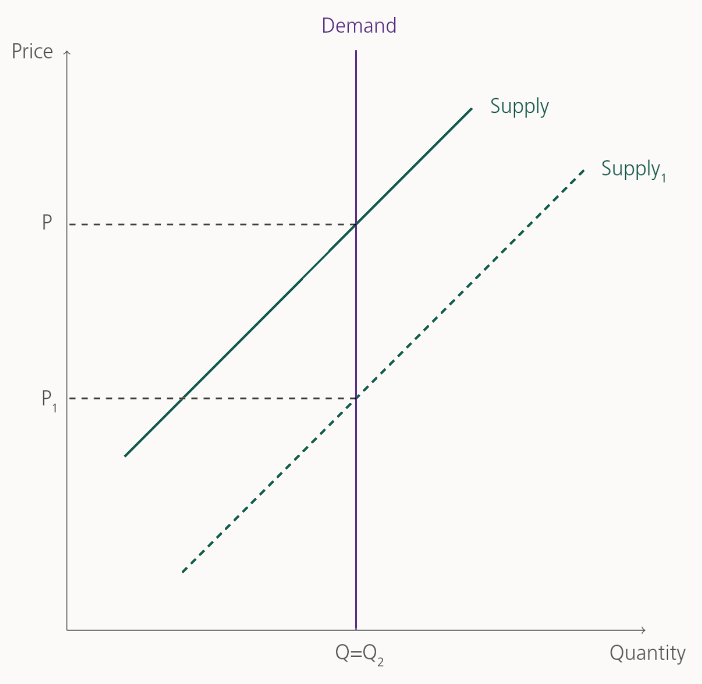
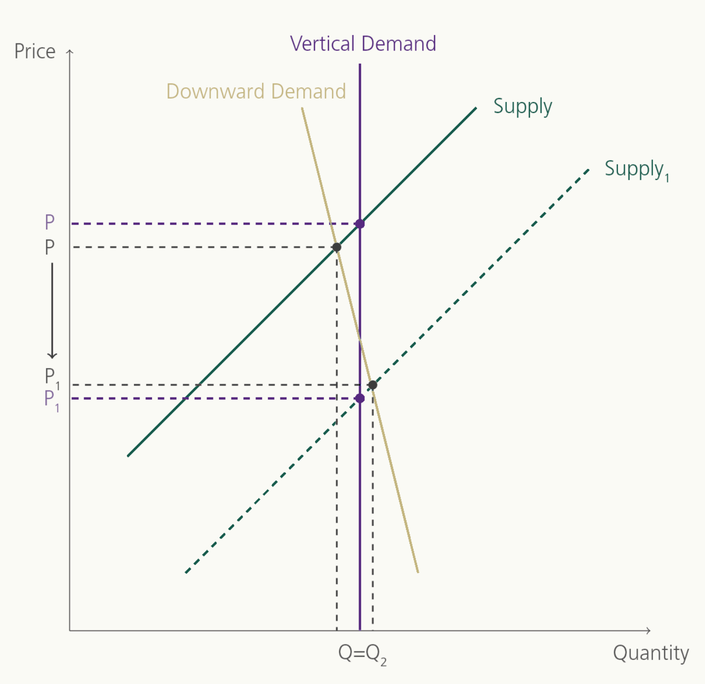


Figure 9: Increase in Supply of Capacity with Downward Sloping Demand Curve



[17] See FERC report, Appendix A.

Forward and Commitment Periods. The forward period is the amount of time an auction takes place before the capacity is needed, and the commitment period is the length of time the capacity is required to be available for generation. The duration of these periods affects the distribution of risk, incentives for market entry and exit, and price stability. A longer forward period provides more time for resources to come on line after winning the auction, and thus increases competition among different supply types. In contrast, short forward periods will discourage new entry or increase costs of entry, increasing risk to generators. A 3-year forward period is often used, based on the average lead time required for construction of a new gas generation facility. However, a longer forward period decreases the accuracy of the forecast for the amount of capacity needed, shifting some risk onto customers, and longer forward periods are less attractive to some supply technologies such as demand response that are less willing to make commitments far in advance.

Longer commitment periods may increase competition among suppliers, and encourage new entry by creating greater certainty for the recovery of fixed costs. Shorter commitments periods may also create difficulties for securing financing due to the uncertainty around revenue after the initial commitment period ends. As a corollary, longer commitment periods contribute to more stable energy prices since prices are locked-in for longer periods of time. However, longer commitment periods increase the importance of accurate demand forecasts, increasing risks to consumers if market conditions change. An additional argument for longer commitment periods is regulatory certainty, which allows suppliers to develop more efficient long-run bidding and investment plans.

Defining Capacity. The definition of the product "capacity" that can take part in the capacity market auction is important in determining the set of technologies making up the supply of generation. Typically, capacity is defined generically in existing markets as products that are able to generate electricity or reduce load as needed so that every megawatt (MW) can be treated equally. However, there are other determinants of system capacity not covered by that definition such as operational characteristics of the system. These include location components that affect transmission constraints, and many capacity markets have bidding by zones. Further, it may be desirable to define the eligible capacity products differentially in order to address particular policy goals or system problems. For example, rapid increases in intermittent renewable generation resources have increased the need for flexible, on-demand generation for load balancing. Defining the operational parameters of capacity resources or performance standards is one way to potentially meet specific system needs. However, this could lead to a significant increase in the complexity of the market both for system operators and suppliers.

A potential disincentive for investment in new technologies in regulated markets is that unsuccessful innovations can still be locked into the utilities' rates for many years, making regulators wary of trying unproven technologies. In contrast, competitive markets will incent any technology with a sufficiently high risk-adjusted return. Since any product able to generate electricity or reduce load is treated equally in a capacity market, these markets have the potential to draw a diverse supply mix. For example, capacity markets can incentivize gains in energy efficiency since they provide a mechanism for directly compensating gains in efficiency. In the United States, approximately 85% of non-pumped hydroelectric energy storage is in competitive markets, and penetration of renewables is approximately 10.6% of generation in competitive markets versus 6.5 in regulated ones.[18] Similarly, demand response in the US has greater penetration in competitive markets with nearly 29,000 MW of potential peak reduction in 2014 versus less than 13,000 MW in regulated environments.[19]

[18] PJM, Resource Investment in Competitive Markets, p.11.

[19] PJM, Resource Investment in Competitive Markets, p.12.

Performance Requirements. Resources that are successful in a capacity auction are subject to performance requirements. Typically, there are two components to these requirements. The first is that the resource is available to produce energy, and the second is a minimum performance standard when energy is produced. Suppliers with more outages can be penalized either financially or through eligibility for future auctions. Well-designed performance requirements ensure that generation is available when needed and that suppliers face appropriate incentives to invest in maintenance and upgrades.

Together, these attributes shape the functioning of a competitive capacity market that can secure electricity generation resources in a flexible, efficient, and low cost manner. Currently, however, Ontario is experiencing an excess supply of generation capacity. What, then, is the argument for including capacity markets in options for generation market reform?

Assessments of Capacity Market for Ontario

The adoption of a capacity auction in Ontario has been under consideration since at least 2014 when the IESO published a report assessing its potential benefits for cost savings from 2019 to 2032 relative to the current system of long term contracting.[20] According to the 2013 Long Term Energy Plan, the province will experience a capacity shortfall beginning in 2019, largely due to retirement and refurbishment of nuclear generation. In their assessment, the IESO assumes that the cost of meeting Ontario's peak capacity requirements under the current system is approximately $130,000/MW-year, which is an estimate of the cost of a new Single-Cycle Gas Turbine generation unit. This is compared to the average "all-in cost" of capacity (i.e., average capacity payments plus energy and ancillary services revenues) and Net CONE in the United States' largest capacity markets, the PJM Interconnection, L.L.C. (PJM) and New York Independent System Operator Inc. (NYISO), over the past 5 years. The average Net CONE in $CDN/MW-year for PJM and NYISO is shown to be comparable to the IESO's costs at $100,000 and $122,000, respectively. However, the average capacity clearing price and all-in costs are estimated to be dramatically lower. The IESO estimates average capacity market prices of $42,900/MW-year for PJM and $42,700/MW-year for NYISO. All-in costs for both regions are estimated to total $50,900/MW-year. Thus, the average capacity market clearing prices and all-in costs are significantly lower than the administratively estimated cost of new generation entry in both markets.

A review of the IESO analysis performed by NERA Economic Consulting notes that in PJM, NYISO, and ISO-NE, capacity clearing prices have consistently been lower than economic or engineering estimates of the cost of new entry. They further point out that this is in part due to the fact that administrative estimates are always of the costs of the average marginal unit instead of the best marginal unit, and a competitive market allows suppliers with the lowest costs to succeed. The IESO assessment goes on to examine the clearing prices and all-in costs in the highest priced zones for PJM and NYISO. Together these average $88,100/MW-year for the capacity clearing price and $96,200/MW-year for the all-in cost. While the highest priced zones have prices and costs approximately double the average zone, the costs are still substantially less than those assumed by the IESO for Ontario under the current system.

If similar prices could be achieved to procure capacity in Ontario, these estimates suggest the potential for large cost savings for the province by transitioning to a capacity market as current generation contracts expire. In 2014, the IESO estimated these savings at $250 million to $500 million per year based on average capacity price figures.

[20] See IESO, Ontario Capacity Auction: Assessment of Expected Benefits.

Updated preliminary estimates from The Brattle Group in 2016 produced similar total benefits with a somewhat different distribution over the planning period.

Is there evidence from other jurisdictions to suggest these estimated cost savings can be realized while maintaining adequate generation capacity and promoting a mix of fuel types and innovation?

Experiences of Other Jurisdictions

The United States has three of the world's most mature capacity markets, the PJM Interconnection, ISO New England (ISO-NE), and New York Independent System Operator, as well as a newer capacity market under the Midcontinent Independent System Operator (MISO). These wholesale electricity markets are operated by regional transmission organizations (RTOs) and independent system operators (ISOs), and are regulated by the Federal Energy Regulatory Commission (FERC). The restructuring of many US electricity markets from traditional regulation to wholesale competition was spurred by the desire for greater operating efficiency and generation performance, and to shift some risk from ratepayers to generators. The attributes and experiences of each of these markets are discussed in turn.

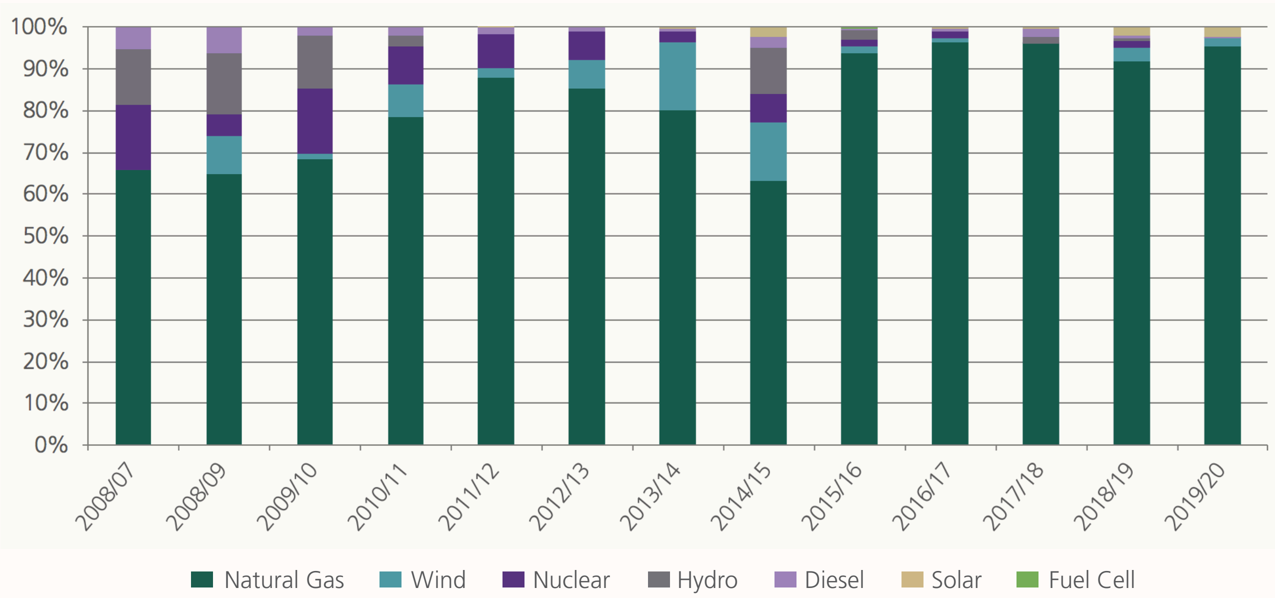
PJM manages a large electric system encompassing 13 states and the District of Columbia. PJM's capacity market has been in operation for more than 10 years using a centralized capacity auction with a 3-year forward period. The commitment period is 1-year with a 3-year commitment option for some new generators. Initially, a vertical demand curve was employed to determine clearing prices in PJM's capacity market, but eventually a downward sloping demand curve was adopted due to concerns over price volatility. The forward auction also maintains a price floor to prevent any resources subsidized outside the capacity market from making excessively low bids. In addition to the main forward capacity auction, PJM holds "realignment auctions" to address forecast changes and to act as a secondary market for suppliers as well as a "Conditional Incremental Auction" to account for delays in large projects.

PJM has been successful in attracting investment and clearing capacity from a diverse mix of supply resources. From 2010 to 2015 approximately 24,000 MW of new generation were committed in PJM's capacity market, 19,500 MW of which were natural gas generation resources. In addition, significant increases in incremental capacity and investment have come from modifications to existing plants ("uprates"). Demand response, imports, and energy efficiency are also an important part of PJMs capacity procurement. Detail on the historic breakdown of PJM's incremental and unforced capacity resources cleared are shown in Figure 10 and Table 3.

PJM has also been successful in efficiently dealing with large scale retirement of coal-fired generation plants resulting in large part from the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards, which set emission standards for hazardous air pollutants from coal- and oil- fired electricity generation. These retirements have been replaced by a combination of low cost new generation, uprates, demand response, and imports.

ISO-NE is a not-for-profit corporation responsible for providing electricity to six states in New England. It has an annual auction for capacity with a 3-year forward period as well as realignment auctions to address forecast updates and to act as secondary market. The commitment period for the auction is 1 year with an option for new generators to contract for 5 years. ISO-NE initially maintained a vertical demand curve and experienced significant excess supply. Consequently, the first seven auctions cleared at the administratively set price floor. The eighth

Figure 10: PJM Incremental Capacity Additions by Delivery Year & Fuel



Source: PJM Interconnection, 2019/2020 RPM Base Residual Auction Results, www.pjm.com.

Table 3: PJM Unforced Capacity Procured by Type & Delivery Year (MW)

Delivery Date	New Generation	Generation Uprates	Imports	Demand Response	Energy Efficiency	Total
2014/15	415.5	341.1	3,016.5	14,118.4	822.1	18,713.6
2015/16	4,898.9	447.4	3,935.3	14,832.8	922.5	25,036.9
2016/17	4,281.6	1,181.3	7,482.7	12,408.1	1,117.3	26,471.0
2017/18	5,927.4	339.9	4,525.5	10,974.8	1,338.9	23,106.5
2018/19	2,954.3	587.6	4,687.9	11,084.4	1,246.5	20,560.7
2019/20	5,373.6	155.6	3,875.9	10,348.0	1,515.1	21,268.2

Source: PJM Interconnection, 2019/2020 RPM Base Residual Auction Results, www.pjm.com.

auction in February 2014, however, resulted in a capacity shortfall and, thus, an administratively set scarcity price. Subsequently, ISO-NE implemented a downward sloping demand curve to reduce price volatility. Auction clearing prices and quantities in ISO-NE to date are shown in Table 4. Total capacity in ISO-NE includes a mix of existing generation, new generation, imports, and demand response with approximately 3-6% of cleared capacity filled through imports and 7-10% through demand response. New generation also included a mix of gas, wind, solar, and fuel cell technologies.

Table 4: ISO-NE Forward Capacity Auction Results by Delivery Year

Auction	Delivery Year	Total Capacity Acquired (MW)	New Demand Resources (MW)	New Generation (MW)	Clearing Price ($/kW-Month)
1	2010/11	34,077	1,188	626	$4.50
2	2011/12	37,283	448	1,157	$3.60
3	2012/13	36,996	309	1,670	$2.95
4	2013/14	37,501	515	144	$2.95
5	2014/15	36,918	263	42	$3.21
6	2015/16	36,309	313	79	$3.43
7	2016/17	36,220	245	800	$3.15
8	2017/18	33,712	394	30	$15.00 (new) $7.03 (existing)
9	2018/19	34,695	367	1,060	$9.55
10	2019/20	35,567	371	1,459	$7.03

Source: ISO New England Inc., www.iso-ne.com.

NYISO operates the electricity grid and manages wholesale electricity markets for the state of New York. NYISO's capacity market is unusual in operating a prompt capacity market with its longest forward period at 30 days, its longest commitment period at 6 months, and separate auctions for summer and winter capacity. Despite the short forward period, new generation, representing 30% of the current capacity of New York's power plants, has been added since the start of New York's wholesale electricity market. From 2000-2016, those additions totaled more than 11,600 MWs, and more than 80 percent of the new generation has been added in the Hudson Valley, New York City and Long Island, where demand is highest. In addition, demand response and energy efficiency programs are expected to significantly contribute to addressing peak demand. Demand response contributes more than 1,200 megawatts of resources, and energy efficiency is expected to reduce peak demand by 255 megawatts in 2016, growing to more than 1,800 megawatts in 2026. NYISO originally employed a vertical demand curve to determine clearing prices in the capacity market but, as with PJM and ISO-NE, switched to downward sloping demand curve due to concerns over price volatility.

The Midcontinent Independent System Operator (MISO) is involved in delivering power to 15 states and Manitoba. MISO has a newer capacity market with a very different structure from that of PJM, NYISO, or ISO-NE. Currently, MISO operates a voluntary annual capacity auction for nearly immediate delivery that is only one of several ways load-bearing entities can secure required capacity. Due to its unique design, it is difficult to compare MISO to the centralized, forward capacity markets of PJM, NYISO, and ISO-NE. In many ways MISO's market design is more similar to that of Western Australia than other large U.S. markets and has experienced similar problems in attracting investment. As such, concerns have arisen that without intervention MISO may fall short of its reliability standards. Consequently, in November 2016 MISO filed a market restructuring plan with FERC to create a 3-year forward capacity auction with a downward sloping demand curve, similar to that of PJM.

Lessons for Ontario

The experiences of other jurisdictions in implementing capacity markets have many lessons and caveats to take into account in designing such a market for Ontario. Designing successful capacity markets requires a clear understanding of the current resource needs and challenges for competition, investment and resource adequacy in the energy market and developing a market structure consistent with these characteristics. Capacity markets have shown themselves to be able to meet capacity needs competitively through a mix of supply types and technologies and to make uneconomic generators more likely to retire since their costs are not supported by ratepayers. Overall, experience in the United States has shown that competitive capacity markets can be subject to substantial price volatility. This volatility can be moderated by the shape of the demand curve estimated, and all US markets are moving toward the use of downward-sloping demand. However, this volatility is at times a feature of a competitive market that is fundamental to its ability to balance supply and demand pressures.

It is important to note that adopting just a single policy component, such as a capacity market, from another jurisdiction's electricity system is not necessarily a panacea for Ontario's generation investment challenges. Electricity markets are complex arrangements where individual components are closely interconnected, implying that the performance of any one component depends on the performance of others. Naively importing just one element without recognizing such interdependencies is a risky proposition. Successful capacity markets in other jurisdictions rely crucially on well-functioning wholesale energy, ancillary services, and secondary capacity markets. Generators typically require access to wholesale energy and ancillary services markets, in addition to a capacity market, in order to recover fixed costs. Ancillary services include a variety of services that contribute to the reliability and security of the electrical grid. Secondary or intermittent capacity markets are also important for the efficient operation of capacity markets, since they allow both the system operator and generators to adjust to changes in demand forecasts or facility construction, upgrade, and refurbishment time lines. Hence, while capacity markets can in theory improve efficiencies in generation, their introduction and design should account for existing institutional features of the existing electricity system, and may require reforms to related components.

Further, promoting goals beyond the provision of reliable electricity at least cost such as job promotion, specific fuel types, etc. reduces the efficiency of the market and can affect its ability to attract investment, suppress clearing prices or crowd out competitive unsubsidized resources. Because demand curves for capacity markets are either vertical or steeply downward sloping, even small subsidies can have significant effects on market prices. Thus, proper governance is crucial to obtaining the greatest benefits from a capacity market. The large regional capacity markets of the United States have the benefit that they span multiple political entities and, consequently, are less subject to government policy decisions that would affect their markets. In the words of Crampton and Ockenfels (2012), "…a capacity market does little to protect against the harm caused by politically induced uncertainties."

CONCLUSIONS

Wholesale electricity markets in all jurisdictions exhibit a variety of imperfections and distortions that impede efficient production, investment and consumption decisions. In Ontario, the hourly market energy price does not provide a meaningful economic signal of the state of the wholesale generation market as a consequence of long-term power purchase contracts that influence generators' bidding strategies in the wholesale market. Wholesale market prices thus do not reflect the average economic costs of generating electricity or even the marginal costs. Instead, the combined hourly energy price and Global Adjustment, which is akin to average cost pricing, provides long-run incentives to generators for investment in new capacity, though short-run production and consumption efficiencies that would arise from marginal cost pricing are foregone.

Despite the rapid escalation in generation costs that Ontario has experienced since 2005, there are opportunities both to smooth rates and electricity bills for consumers in the short run and to improve the efficiency of Ontario's generation market moving forward. This report describes two options for smoothing contracted generation costs with the potential for reductions equal to 8% or more of total expected electricity system costs in 2018. In addition, the introduction of a capacity market for future generation procurement could reduce costs relative to the current system of long-term contracts and increase system efficiency while reducing risks to ratepayers.

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