

# The Economic Cost of Electricity Generation in Ontario

## EXECUTIVE SUMMARY

- The overall cost of electricity generation, which accounts for almost two-thirds of Ontario's total system costs, has increased significantly since 2005 mainly due to a substitution away from coal generation towards more costly renewable sources, and a parallel increase in the total amount of installed capacity in the province, notably due to an expansion in the amount of natural gas capacity.
- The unit cost of electricity generation is approximated by the sum of the wholesale market price and the Global Adjustment. Wholesale market prices reflect, in part, short-run variable costs, but often fall short of the total cost of producing electricity, which includes significant fixed capital costs. The Global Adjustment is a mechanism that, in conjunction with the wholesale hourly market price, ensures recovery of variable and fixed generation costs. As such, the Global Adjustment is not an overpayment but a component of the full economic cost of generating electricity.
- Recent increases in consumers' electricity bills have been driven in part by the rapid expansion of generation capacity in the province, much of which has been financed under 20 year contracts with private firms. Current rates and electricity bills could be reduced by amortizing contracted generation capital costs over longer periods to match the productive lifespans of the assets, often longer than the contracted terms. The cost of generation charged on consumer bills would then more closely reflect the economic cost of the assets. A policy of smoothing generation costs through government subsidies in the short-term would incur interest charges and would lead to higher bills in the long-term.

## 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 confusion over the reasons why bills have increased. While a comprehensive analysis of electricity system costs and consumer bills is outside the scope, 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 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, often 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 electricity market prices can 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 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 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, often rely on complementary 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 on generator incentives, introducing further complexities and distortions in 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).<sup>1</sup>

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 Progressive Conservative government launched a competitive wholesale

<sup>1</sup> The rate freeze remained in place until the Government launched the competitive retail market in 2002.

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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). 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 state-owned 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 sought to rebuild the supply portfolio to address a generation shortfall, and also to rebalance the supply mix, notably by reducing the share of coal generation while phasing in renewable sources such as wind and solar.<sup>2</sup> Since the private sector was reluctant to invest in merchant generation assets, the government created the Ontario Power Authority (OPA) in 2004 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 a specified time period, commonly 20 years.<sup>3</sup>

Since 2005, the OPA (now the IESO) has contracted for approximately 6,000 MW of wind capacity and more than 2,600 MW of solar capacity (IESO, 2016a). In total, the IESO has contracted for more than 27,000MW of energy. Ontario Power Generation (OPG) controls significant additional nuclear and hydroelectric capacity whose rates are regulated by the Ontario Energy Board.

Figure 1 shows how the province's generation profile, including both contracted and regulated components, has changed over the eleven year period since 2005. Overall, the province expanded its installed generation capacity by a net 8,000 MW, increasing to a total of approximately 38,500 MW in 2016. Nuclear power has remained the single largest component, accounting for 11,400 MW in 2005 (37% of total capacity), increasing to 13,000 MW in 2016 (34%). Hydroelectricity was the second largest component in 2005 at 7,900 MW (26%), and has increased marginally to 8,500 MW in 2016 (22%). The most significant changes have been in renewable and natural gas generation. Wind, solar and bio-energy power sources added 7,100 MW over the eleven year period, and accounted for 18% of total installed capacity in Ontario in 2016. Natural gas installed capacity doubled between 2005 and 2016 (adding approximately 5,000 MW), increasing its share from 16% to 26%. Coal, which accounted for 21% of capacity in 2005, was eliminated from the supply mix by April 2014.

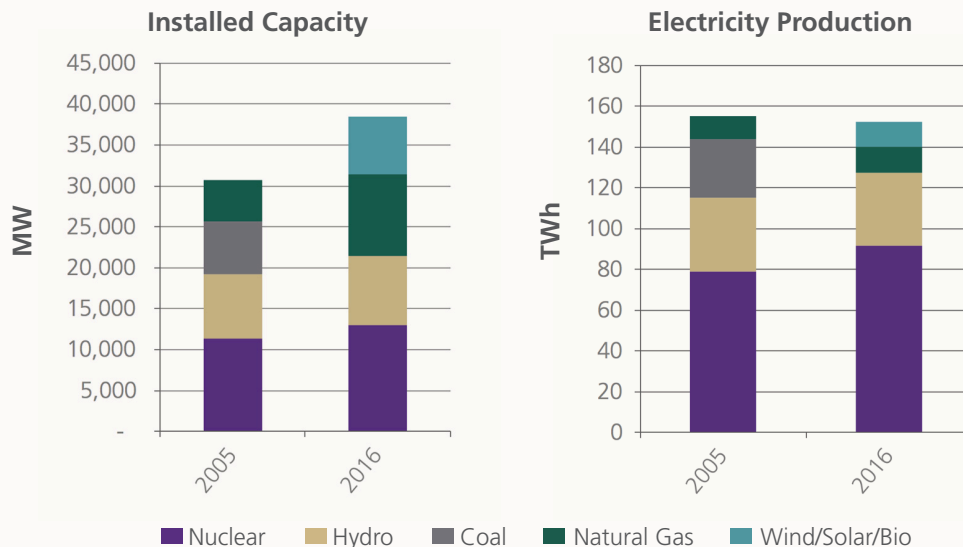
In terms of electricity production, overall power output in the province decreased marginally from 155 TWh in 2005 to 152 TWh in 2016. Nuclear accounted for the majority of output (92 TWh, 60% of overall output in 2016), and has increased both the absolute amount and its share of output since 2005. Hydroelectric power generation has remained steady at 36 TWh, and is the second largest component of overall output (23% in 2005 and 2016). Wind, solar and bio-energy accounted for approximately 8% of power output in 2016 (12 TWh). Natural gas output increased marginally between 2005 and 2016, despite the doubling of capacity, and accounted for about 8% of total output in 2016.

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<sup>2</sup> Electricity Conservation and Supply Task Force, Final Report to the Minister, January 2004

<sup>3</sup> Contracts for natural gas generation were more complex and included clauses for fixed monthly payments.

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 in large part 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, and is included in the ‘Global Adjustment’ generation charge. The Global Adjustment consists of the costs of payments to contracted generators, as well as the costs of conservation expenditures, and payments to regulated generators. It exists because, in general, market-based revenues are insufficient to cover the full costs of contracted or regulated generation. The combination of the Global Adjustment and the Hourly Ontario Energy Price effectively represents average cost pricing, enabling generators to recover their variable and fixed costs.

## Wholesale Electricity Market

Ontario’s wholesale electricity market operates as a mechanism for dispatching generation units in order to ensure a reliable and continuous supply of electricity. The wholesale market price—the HOEP—is determined by offers submitted in advance by generators that specify the amount of power they are willing to provide and the offer price. The HOEP is the hourly average of twelve five-minute market-clearing prices that balance supply and demand. The five-minute market-clearing price, and ultimately the HOEP, is based on the offer of the marginal generating unit, and all dispatched generators, regardless of their offer, receive market revenues at the market-clearing price. Generators that submit offers greater than the five-minute market-clearing price are not dispatched and do not receive wholesale market revenues.

Since 2005 there has been a declining trend in the hourly energy price on the wholesale market, as illustrated by

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**Figure 2.** Contributing factors include falling natural gas prices, lower demand for electricity within the economy, and expansion of generation capacity with low to zero marginal costs such as wind, solar and hydro. In the eight year period 2009 to 2016, the hourly energy price averaged \$28/MWh, significantly below the average total cost of virtually any type of generation technology. Such wholesale prices are insufficient by themselves to incent investment in new dispatchable generation capacity, for instance natural gas, which is needed to complement the growth of intermittent renewable generation.

The decline in Ontario's wholesale market price does not necessarily imply that the average cost of generation has also declined, nor is the wholesale price necessarily an indicator of the average generation cost at any point in time. Two explanations are germane: first, in generation markets with excess capacity, such as in Ontario, wholesale prices are largely determined by variable or marginal production costs, not by average costs which additionally reflect fixed capital costs. A significant presence of renewable resources, which have low variable costs, further drives a wedge between wholesale prices and average costs.

Second, strategic behaviour by generators can distort wholesale prices below even their marginal costs of production. For instance, before September 2013, renewable generators such as wind and solar were at times submitting offers to the market at prices equal to -\$2000 per MWh. Notionally, an offer 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 knew that they were guaranteed to receive their contracted, fixed power purchase rate per MWh and wanted to ensure their power gained a favourable position in the merit order and was dispatched. Due to such strategic bidding behaviour by generators, between 2009 and 2014, the HOEP was negative for almost 2000 hours (equivalent to 83 days).<sup>4</sup> In response, in late 2013 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). Similarly, manoeuvrable nuclear generators have an offer floor of -\$5 per MWh to limit strategic bidding. These examples illustrate that generators are not necessarily offering their production cost, but instead are adjusting their offers in accordance with the terms of their fixed price contracts.<sup>5</sup>

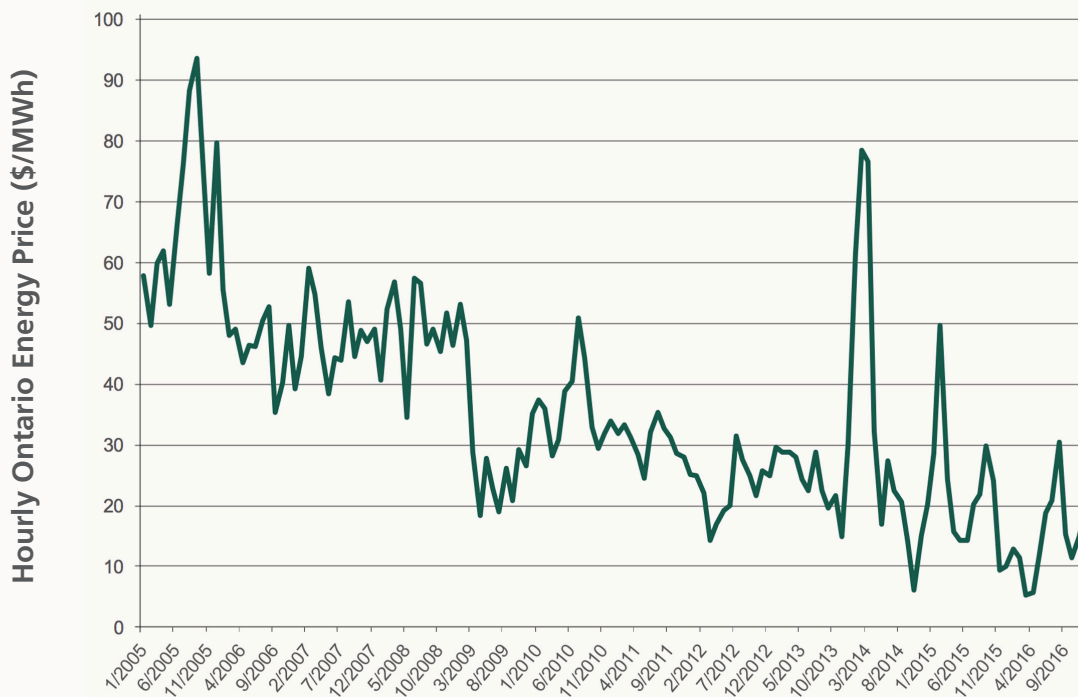
In this sense, generators' long-term purchase contracts can distort the wholesale market price since they reduce the incentives for generators to make offers in the wholesale market based on their cost of production. While the wholesale market price does not provide a perfect economic signal to producers and consumers, this does not imply that the wholesale market dispatch mechanism operates inefficiently over the short-term. Provided that the dispatch merit order is maintained, the five-minute market-clearing price still sends a reasonably accurate signal for short-term dispatch, and generally ensures that lower cost sources of electricity are dispatched before higher cost sources.

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<sup>4</sup> Annual Report of the Office of the Auditor General of Ontario, 2015, page 216.

<sup>5</sup> In a slightly different context, Harvey (2013, pages 1-2) 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



Source: IESO

## 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).<sup>6</sup>

The formal description of the Global Adjustment is outlined in Ontario Regulation 429/04.<sup>7</sup> 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 the Global Adjustment by themselves 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

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

<sup>7</sup> Section 1(1) of 429/04 precisely presents the calculation of the Global Adjustment.

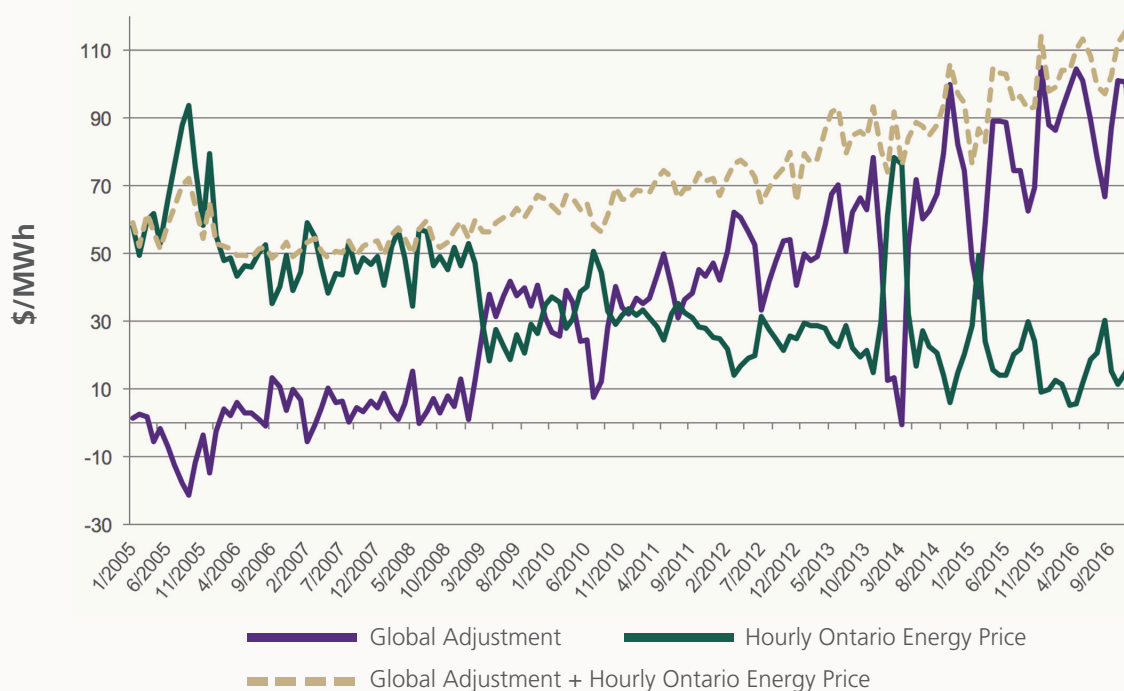
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normal competitive markets. The appropriate counterfactual for Ontario prices is less obvious than it might seem at first inspection and needs to be formulated as the inclusive price that covers both variable and fixed costs in the absence of policy 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.<sup>8</sup> 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



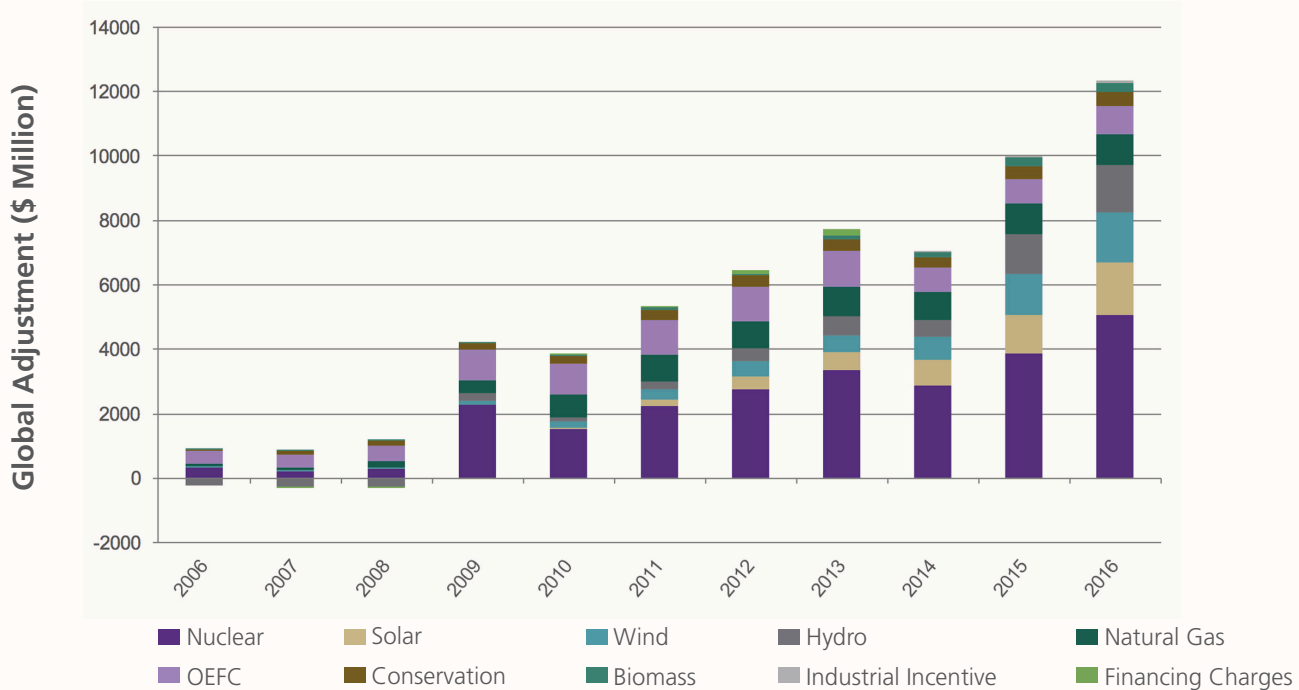
Source: IESO

<sup>8</sup> 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 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%, hydroelectric power for 12%, and natural gas for 8%. Other components summed to 13%.

Figure 4: Global Adjustment by Component, 2006–2016



Source: IESO

## REASONS FOR GENERATION COST 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 the increase in generation costs.

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. Several factors have contributed to this trend:

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**Phase out of low cost 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.

**Increasing share of renewable fuels.** The 2009 *Green Energy and Green Economy Act*, 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, hydroelectric, and bio-energy capacity, supported by fixed feed-in tariffs guaranteed for 20 years. Between 2005 and 2016, the province added approximately 7,100 MW of new wind, solar and bio-energy capacity, accounting for 18% of installed capacity in 2016. The rates paid for renewable power are greater than rates paid for nuclear and hydroelectric power which provide the bulk of electricity for the province, for instance ranging from \$135/MWh for on-shore wind to \$443/MWh for ground-mounted solar PV under the 2012 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 generation costs by fuel type based on total payments to generators operating under all contract and regulation mechanisms. 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). It is notable that the average cost of natural gas power is greater than wind and bio-energy power, despite low wholesale gas prices, which may be account for the low capacity utilization of natural gas generation assets.

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

Generation Fuel	Average Unit Cost (\$/MWh)
Nuclear	66
Hydro	58
Natural Gas	173
Wind	140
Solar	480
Bio-Energy	131

**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.

**Overall growth in installed generation capacity.** Expansion of the province's generation portfolio began in the early 2000s when the economy was growing robustly and when there were heightened concerns about supply outages, especially following the major regional blackout in Ontario and the north east U.S. in August 2003. In addition, given the shift towards renewable power generation, which is intermittent, the province needed to invest in complementary natural gas or other dispatchable capacity that could operate during periods when renewable power was not available. Ontario added 5,000 MW of natural gas capacity between 2005 and 2016, much of which provides peak and mid-peak power, to bolster system reliability and to satisfy regional needs. The overall amount of installed capacity in the province has increased significantly over the last decade. In 2016, installed capacity was approximately 38,500 MW – a 25% increase from 30,500 MW 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, reflecting, in part, the impact of the 2008 Great Recession. Annual peak grid demand has also fallen sharply, from an all time high of 27,000 MW in August 2006 to 22,500 MW in 2015. While long-term forecasting of electricity demand is notoriously difficult, the province has invested in new generation capacity that has proved to be in excess of typical needs, contributing to higher system-wide costs and consumer bills.

## SMOOTHING CONTRACTED GENERATION COSTS

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. While the government has taken some heat for rising bills, there is a potential policy solution that is economically rational 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 for which constitute the bulk 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. Besides wind and natural gas, there may be additional generating assets that present opportunities to smooth costs for consumers. 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.<sup>9</sup> Charges to consumers for contracted generation could hence 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.<sup>10</sup>

There are three possible methods to accomplish generation cost smoothing in Ontario, recognizing that many new contracts with generators have already been signed over the preceding 12 years.

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<sup>9</sup> Generators have strong incentives to fully amortize fixed capital costs over the duration of the contract, and to build these costs into competitive supply bids, even if the contract duration is shorter than the expected lifespan of the asset. Once a generation facility is constructed it becomes a physically sunk asset, leaving the generator with considerably reduced bargaining power at the end of contract. Even if the government wishes the generator to continue operating after the end of the contract, it may offer to purchase power only at the variable or operating cost of production, providing minimal opportunity for the generator to recoup sunk fixed capital costs. As long as the purchase price at least covers variable costs, it is rational for the generator to accept the government's terms and to operate.

<sup>10</sup> The same smoothing principle could be applied to other generating assets where contract durations are less than expected asset lifespans. It is also applicable for expenditures on conservation projects, which can involve upfront investments in capital assets that reduce electricity demand over multiple years. For instance, high efficiency industrial refrigeration compressors are expected to operate for more than a decade. Currently, conservation expenditures are fully recouped in Global Adjustment charges in the year in which they occur. The Ministry of Energy estimates that smoothing conservation expenditures over asset lifespans could reduce electricity system costs in the short term by \$300-\$500 million.

#### 1. 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.

There are several caveats with this approach. First, substantial rate reductions will be achieved only if there is sufficient competitive bidding pressure between generators for contract extensions. Since future demand for electricity in the province may well decrease, the government need not extend all generator contracts, which could create some implicit bidding competition – but the likely degree of competition and downward pressure on rates is uncertain ex ante. Second, the process of negotiating contract extensions could be administratively complex and time consuming for both the government and generators. The government has contracted with thousands of private entities since 2005. Generators would also likely need to renegotiate their own contractual arrangements with a range of parties in addition to the government, including landowners, financiers, local communities, and Aboriginal groups, a complex and uncertain exercise. A third caveat is that providing new long-term contracts to generators could impact the proposed introduction of a capacity market in Ontario if generators became less willing to participate in capacity auctions.

#### 2. Short-term government subsidization of payments to generators

An alternative and potentially simpler 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, though it would increase public sector debt. Generator contracts would be unchanged in this scenario. An advantage of this approach is that it avoids the administrative cost and uncertainty of renegotiating in a short time period multiple contracts on an individual basis with generators, and it can be implemented relatively rapidly. On the other hand, the government would ultimately still need to negotiate new contracts with generators when existing ones expire in the future, in order to ensure that generation assets continue to operate, where needed, beyond 20 years.

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. Generator refurbishment and maintenance costs may also increase for older assets, implying upward pressure on rates when generator lives are extended beyond anticipated contract end dates.

### 3. Long-term contracting policy

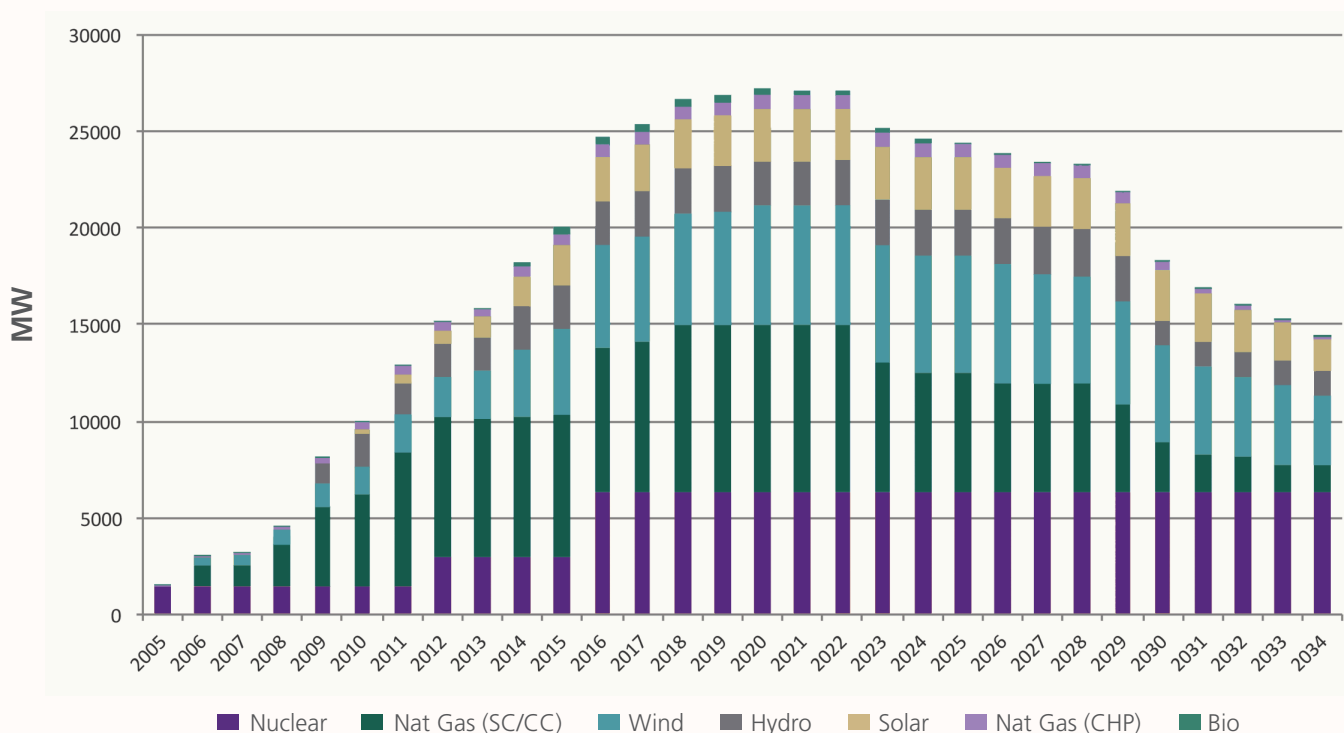
In future contracting exercises for new generation capacity, the government could invite generators to submit bids that include the proposed contract duration, and evaluate such bids on the basis of contract duration as well as on purchase price and other factors. Providing flexibility on duration would 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: Contracted Generation Capacity by Fuel Type, 2005–2034



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

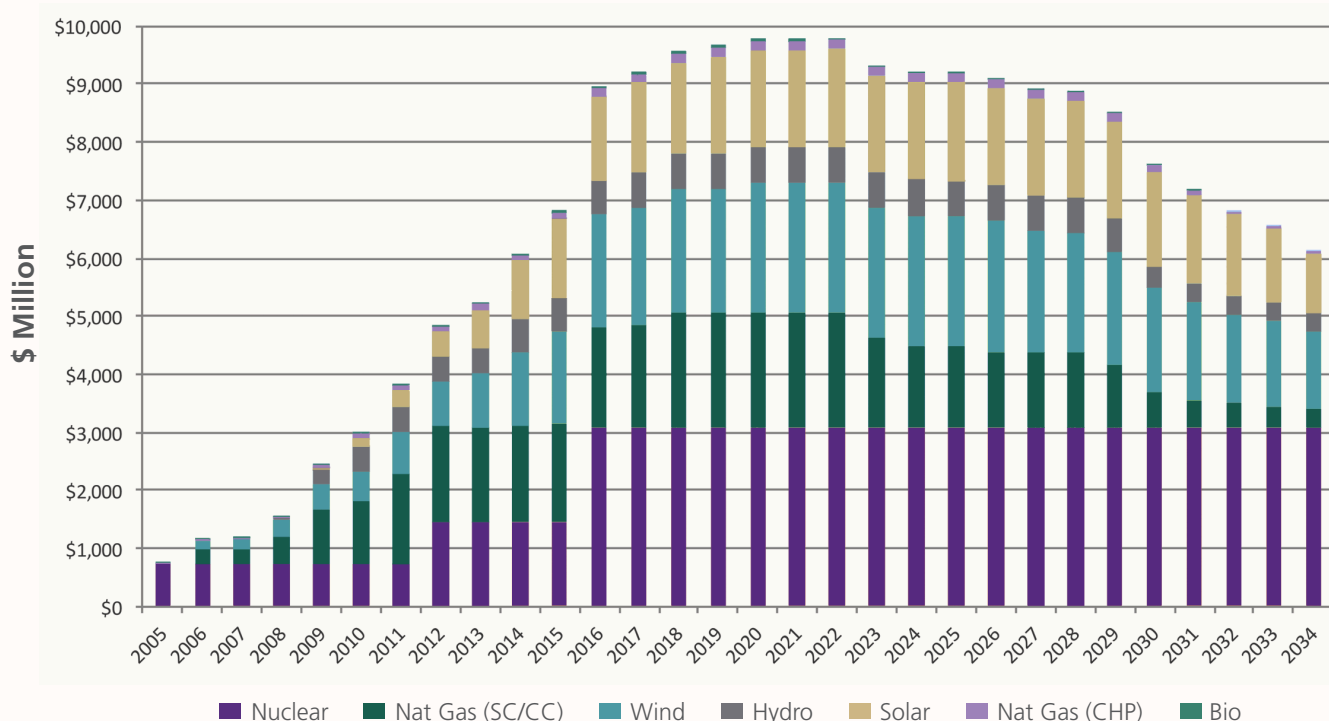
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Figure 5 shows the amount of accumulated contracted capacity for each fuel type for the 30-year period from 2005 to 2034. There has been a significant increase in contracted natural gas generation (representing 33% of total contracted capacity in 2017), 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 fuel type, and IESO data on capacity utilization, leads to approximate estimates of the annual cost of contracted generation capacity.<sup>11</sup> In 2016, payments to contracted generators are estimated to have totalled 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.

Figure 6: Estimated Cost of Contracted Generation, 2005–2034



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

<sup>11</sup> 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<sup>12</sup>

	IESO contract duration (range)	IESO contract duration (mid point)	IEA lifespan estimate <sup>13</sup>	EIA lifespan estimate <sup>14</sup>
<b>Natural Gas</b>	10–20 years	15 years	30 years	30 years
<b>Wind</b>	20	20	25	30
<b>Nuclear</b>	31–57	44	60	
<b>Hydro</b>	20–50	35	80	
<b>Solar</b>	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 (existing contracts are assumed to all be for 20 years). 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. 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%.<sup>15</sup>

In 2018, the total value of reductions in natural gas, wind and solar generation capital charges is estimated to be in the range of \$1.5–\$2.0 billion (see [Figure 7](#)), equivalent to approximately 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.<sup>16</sup> 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 higher for several years than they would have been without smoothing.

<sup>12</sup> 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).

<sup>13</sup> International Energy Agency. 2015. Projected Costs of Generating Electricity.

<sup>14</sup> Energy Information Administration. 2016. Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2016. August 2016.

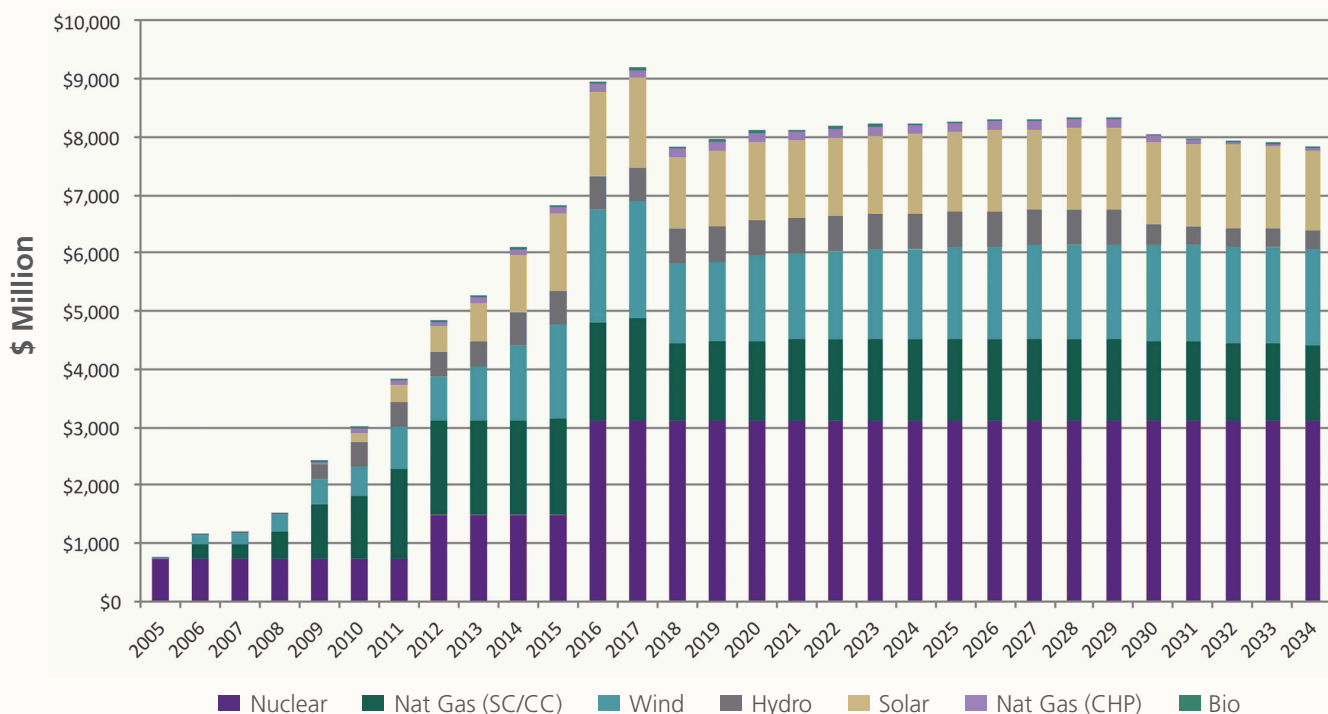
<sup>15</sup> Smoothing is applied only to the assumed capital component of unit generation costs. For wind and solar power which have zero fuel costs, and relatively low variable operation and maintenance costs, it is assumed that 90% of the power purchase rate is accounted for by capital costs. For 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.

<sup>16</sup> 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. Annual interest charges on the accumulated debt are assumed to be paid in full in each year by ratepayers through inclusion in electricity bills.

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Figure 7: Estimated Smoothed Cost of Contracted Generation, 2018-2034



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

These estimates are preliminary and reflect the specific assumptions of the model. Alternative assumptions would naturally lead to larger or smaller reductions in near-term contracted generation costs. They are also calculated 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 all contracted generators participated and agreed to equivalent reductions in power purchase rates.

While smoothing generation costs can ease the transition for current households and firms to a higher cost electricity system, there are risks and limitations associated with such a policy. One risk is that future changes in markets, technologies, government policy, or demand for electricity may reduce the need for longer-lived generation capacity, potentially creating future stranded costs. In addition, an important consequence of smoothing is that it raises questions about inter-generational equity since consumers in the long-term future will contribute towards a larger share of generation capital costs, and consumers will also pay interest costs associated with short-term subsidization of rates. Some commentators have advocated for the status quo, citing the imposition of interest costs on future consumers as inequitable. However, the corollary to this argument is that the current approach of amortizing generation capital costs too quickly relative to expected lifespans is effectively a subsidy by current ratepayers of future consumers, who would have usage of the assets but not have to contribute to their capital costs. In addition, as economic growth continues, future generations will be wealthier than today, making any given level of electricity costs more affordable.



## CONCLUSION

Wholesale electricity markets in many jurisdictions exhibit a variety of imperfections that affect investment, production, and consumption decisions. Wholesale market prices for electricity, including in Ontario, often do not provide an accurate representation of the full economic cost of production, which consists of short-run variable costs (e.g. fuel costs) and long-run fixed capital costs. Wholesale prices are often determined instead by short-run variable costs, especially in environments where there is excess generation capacity, implying that additional mechanisms—such as long-term power purchase contracts—are needed to enable generators to recover their full costs.

Since 2006, the hourly market price for electricity in Ontario has steadily fallen, owing to a decrease in demand and the addition of new capacity resources with low short-run variable costs. At the same time, the underlying cost of generation has increased as the province has made investments in new and refurbished capacity to ensure system reliability and to replace coal, and also added wind and solar supply—which are more costly than nuclear, hydro-electric, and coal generated power—in order to achieve environmental goals. The full cost of generation is reflected in the sum of the hourly wholesale market price (HOEP) and Global Adjustment, which enables generators to recover both short-run variable and long-run fixed costs of electricity production. The Global Adjustment is thus an important component of ensuring a well-functioning generation sector.

Despite the rapid escalation in generation costs that Ontario has experienced since 2005, there is an economic rationale for smoothing rates and reducing electricity bills for consumers in the short-run. Amortizing contracted generation capital costs over longer periods to match with the productive lifespans of the assets, which are often longer than the contracted terms, could reduce current electricity system costs by approximately eight percent, a preliminary estimate. Under this approach, the cost of generation charged on consumer bills would more closely reflect the true economic cost of the assets. A policy of smoothing generation costs through government subsidies in the short-term would incur interest charges and would lead to higher bills in the long-term, raising the challenging issue of inter-generational equity.

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