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Power Surge: The Causes of (and Solutions to) Ontario's Electricity Price Rise Since 2006

by

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- Ontario's electricity sector has struggled with rising system costs for more than a decade. Why? The crux of the problem are increases in the cost of supply from high-cost contracts spread over less electricity consumption than forecast when the contracts were struck. The result has been upward pressure on prices that has only been mitigated by government rebates that have shifted costs to taxpayers.
- How can Ontario fix this? To help businesses, it should replace the current industrial electricity pricing system for large customers with a market-based "interruptible rate" that rewards them for agreeing to interruptions of supply during extreme peak demand hours. For medium-sized customers, set the full cost of energy prices on an hourly basis.
- For residential customers and small businesses who pay regulated energy rates, we propose giving consumers the option of a lower price than otherwise most of the time, but with an incentive to reduce use at extreme peak demand hours.
- The Ontario government should provide sound policy direction that focuses on empowering and resourcing the regulator, the Ontario Energy Board (OEB), to oversee decisions on procuring electricity, moving electricity procurement decisions to local buying groups.
- Policymakers should recognize the cost containment in the distribution and transmission side of the system led by Hydro One since its 2015 partial sale. Since privatization, Hydro One has lowered its overall cost per customer by $90, mostly by reducing administrative costs. To help other local distribution companies emulate those savings, which we estimate would save customers of other LDCs $61 per year, the province should implement tax changes that allow cities to find outside investors while simultaneously unlocking value for municipal taxpayers.
- Lastly, the province should reduce rate subsidies, which have climbed to $6.5 billion in the 2021/22 fiscal year. For comparison, this is $700 million more than what the province plans to spend on long-term care. They are not sustainable.

Rising costs have burdened Ontario's electricity system for well over a decade and yet there remains no end in sight. Ontario had the highest system costs among the provinces in 2018 (Bishop, Shaffer, Ragab 2020).

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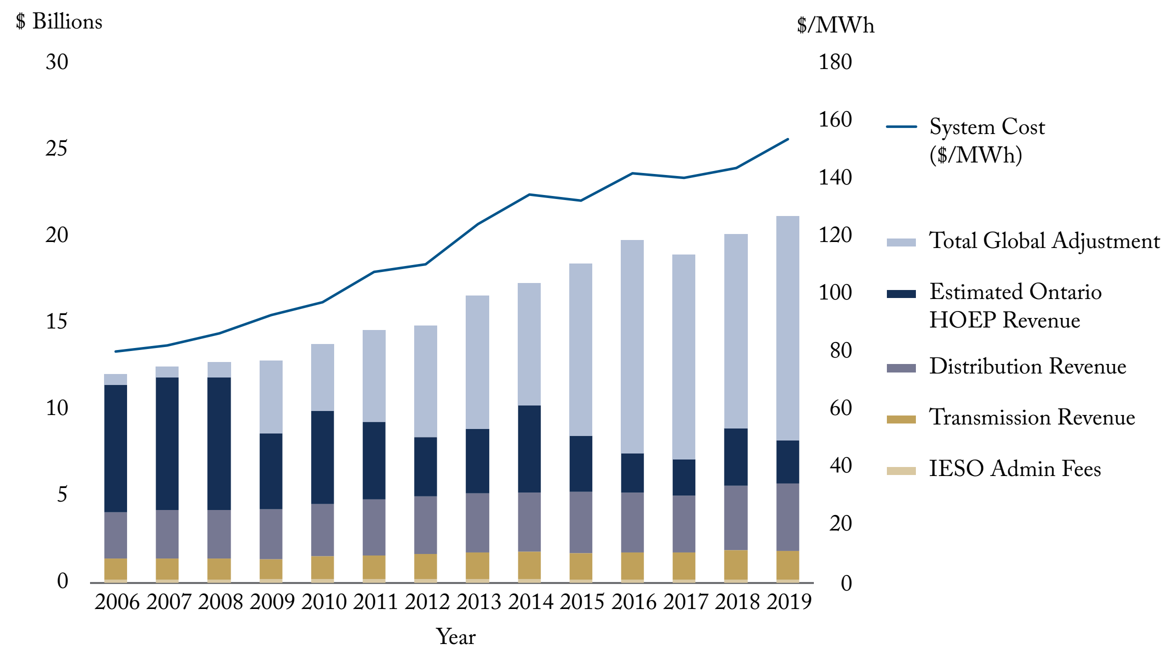
Figure 1: System Cost by Component



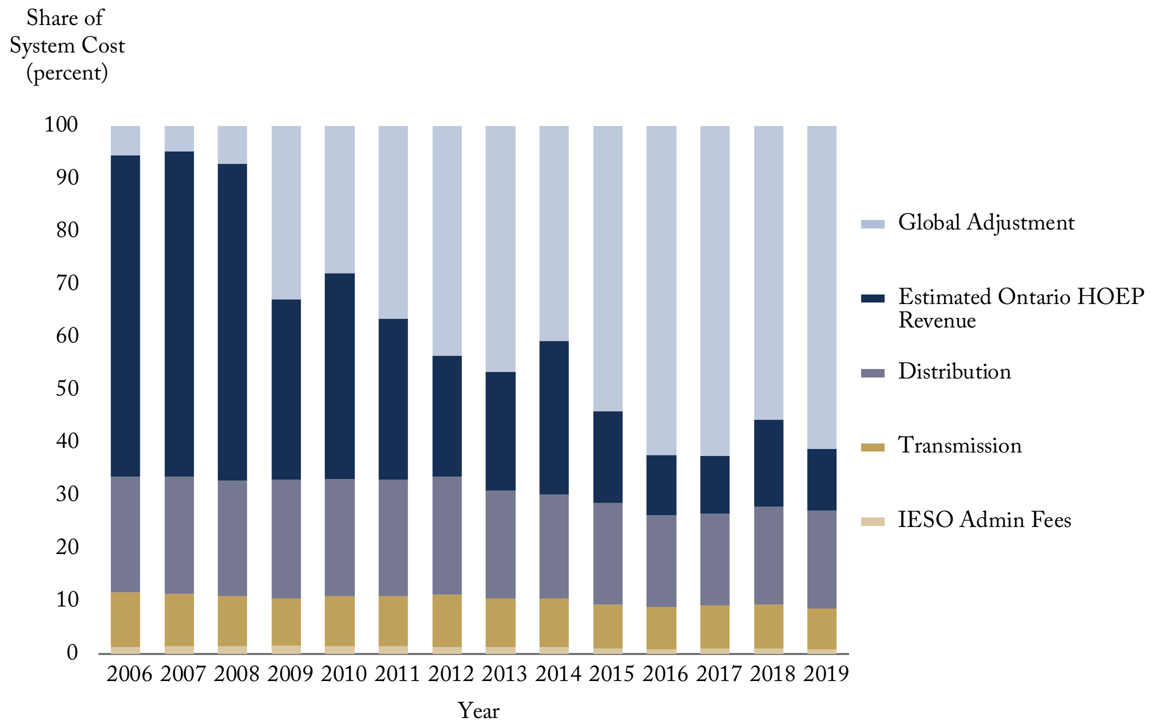
Sources: Ontario Independent Electricity System Operator (IESO), Ontario Energy Board, Hydro One.

Ontario's electricity system is separated into generation, transmission, distribution, and (a relatively minor cost) market operation by the Independent Electricity System Operator (IESO). The system's total cost reflects the revenues raised by each component. Total system cost has increased from $12 billion in 2006 up to $21 billion in 2019 (Figure 1). Over the same period, Ontario demand has fallen by approximately 10 percent, well below the originally forecast levels from 2007 (IESO 2021a).[1]

Generating facilities, whether for hydro, natural gas, nuclear, or other energy, in Ontario collect revenue through a mix of payments from (i) long-term power contracts (the net amounts paid under these contracts are aggregated into the "Global Adjustment" or "GA") and (ii) payments from the real-time wholesale market ("the Hourly Ontario Energy Price" or "HOEP"). These revenues combined represent the cost of energy and comprise the largest portion of the system cost in Ontario as expressed in Figure 1 and Figure 2. While revenues from the HOEP have fallen from $7.4 billion in 2006 to $2.5 billion in 2019, revenues from the GA have soared from $700 million to $13 billion over the same period. The long-term power contracts covered by the GA are designed such that if the revenues from the HOEP are insufficient to cover the returns as specified in the energy contracts or regulated rates, the compensating payments from the GA make up the difference (IESO 2021b). With energy costs set by contracts, if the HOEP is lower, the GA is higher. The GA is now the single largest component of the total system cost at over 60 percent in 2019.

1 We use 2006 for the aggregate system cost data analysis as our base year as that is the first year in which we have consistent data for all parts of the system.

Figure 2: Share of System Cost by Component



Sources: Ontario Independent Electricity System Operator (IESO), Ontario Energy Board, Hydro One.

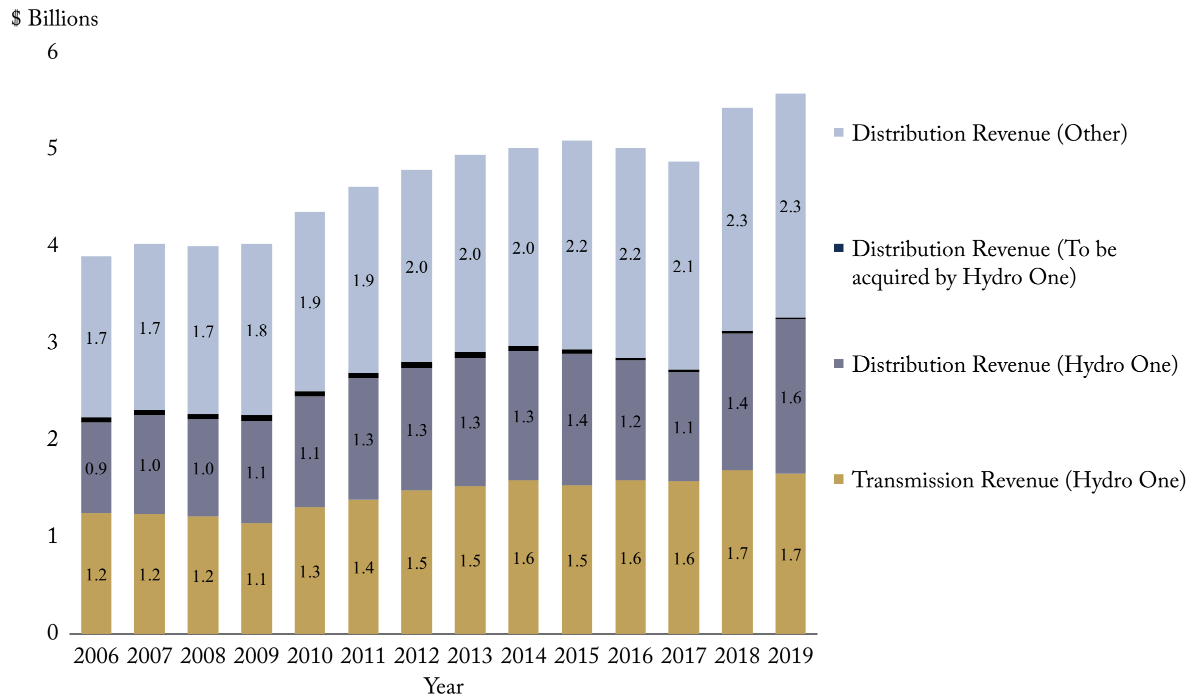
Transmission in Ontario is almost entirely provided by Hydro One. The revenues accrued by Hydro One through transmission have increased from \$1.2 billion in 2006 to \$1.7 billion in 2019 as shown in Figure 1, however, transmission's share of the total system cost has declined slightly as illustrated in Figure 2.

Numerous local distribution companies (LDCs) provide services in Ontario, with a total of 59 LDCs operating in 2019, including Hydro One (OEB 2021a). Distribution represents a larger cost than transmission, with costs climbing from \$2.7 billion in 2006 up to \$3.9 billion in 2019. Despite this, distribution's share of system costs has similarly fallen over the years as expressed in Figure 2. Transmission and distribution's combined share of the total system cost in 2019 was slightly more than 25 percent compared to 33 percent in 2006.

Transmission & Distribution

To explore transmission and distribution revenues further, we segregate Hydro One into its transmission and local distribution companies operating in Ontario, as well as LDCs that eventually became acquired by Hydro

Figure 3: Grid Costs Expressed by Transmission and Distribution Revenues



Sources: Ontario Independent Electricity System Operator (IESO), Ontario Energy Board, Hydro One.

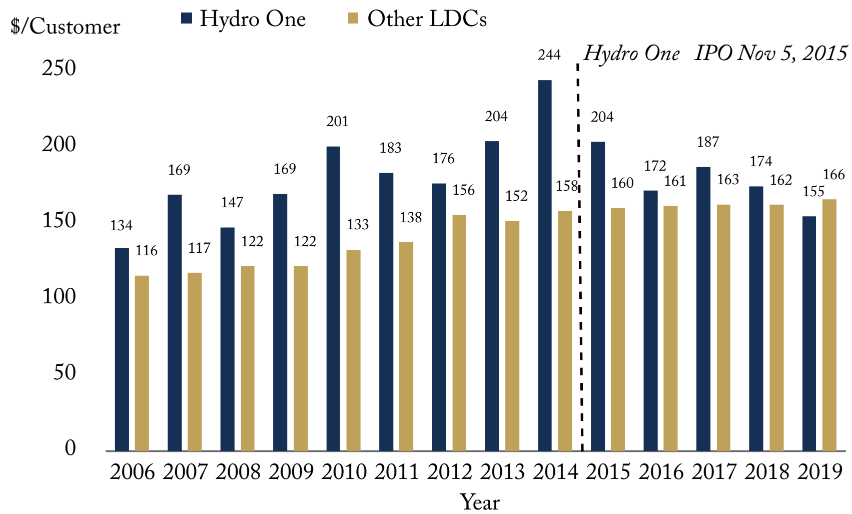
One, and all remaining LDCs.[2] Total distribution revenues for Hydro One have increased from $900 million in 2006 up to $1.6 billion in 2019, while distribution revenues for other LDCs have increased from $1.7 billion to $2.3 billion over the same duration, as illustrated in Figure 3 (which we explore further, controlling for customer density, below). In 2015, the previous government began its first phase of privatization of Hydro One, and Ontario now owns slightly less than half of shares (Hydro One 2020).

Of the major categories of distribution expenses, which include depreciation/amortization, financing, operating, maintenance, and administrative, the latter is where LDCs have the most leeway to create efficiencies.[3] Between 2006 and 2014, before its privatization, Hydro One's administrative expenses increased 82 percent from $134 per customer up to $244 per customer, while those of other LDCs increased 36 percent from $116

2 Between 2006 and 2019, Hydro One acquired Woodstock Hydro Services, Haldimand Country Hydro, Norfolk Power Distribution, and Terrace Bay Superior Wires. In 2020, Hydro One acquired Orillia Power Distribution and Peterborough Distribution. We do not include Hydro One Brampton as part of Hydro One in historical analysis here or in subsequent analysis, as it operated as a separate company until it was merged into Alectra. These purchased utilities represent a small share of total sector costs and are not a material part of the analysis. Hence we do not distinguish these acquired LDCs in our later analysis.

3 Between 2006 and 2019, administrative costs for Hydro One have been about 22 to 25 percent of total costs. For the rest of Ontario LDCs, administrative costs are approximately 28 to 33 percent of total expenses.

Figure 4: Distribution Administrative Expenses for Hydro One vs Other LDCs



Note: These administrative expenses are only from distribution, and do not include expenses from transmission.

Sources: Ontario Energy Board and authors' calculations.

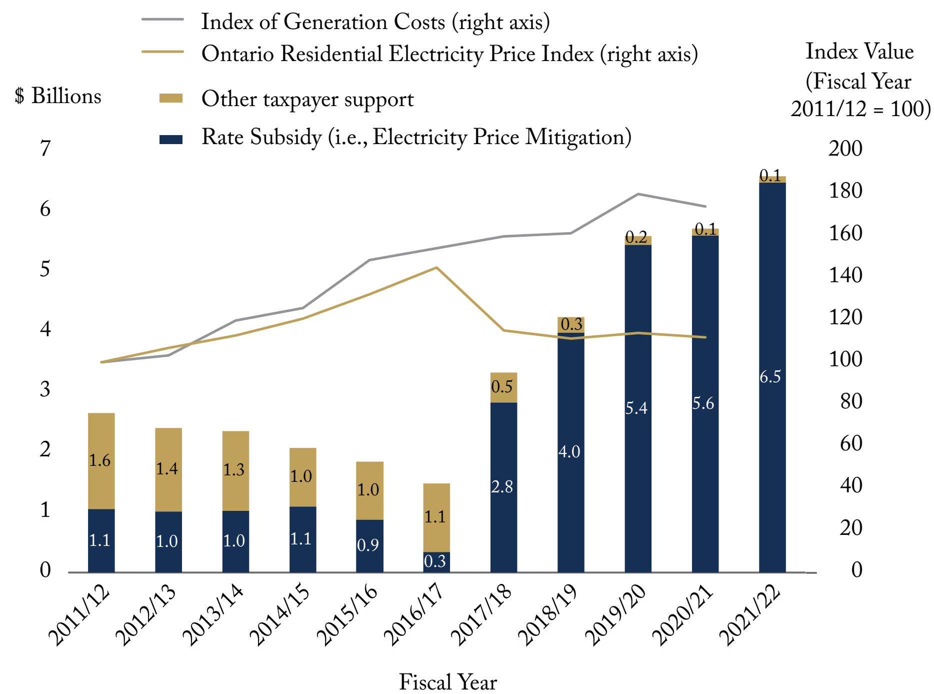
per customer to $158 per customer over the same duration. Even excluding its final year as a wholly owned Crown corporation, in which administrative costs rose the most, Hydro One's pre-privatization administrative cost increases were faster than the rest of the sector. The situation changed after 2014. While other LDCs saw their average administrative expense per customer rise 5 percent from $158 per customer in 2014 to $166 per customer in 2019, Hydro One's fell by 36 percent from $244 per customer to $155 per customer over the same period as illustrated in Figure 4.[4]

The Role of Taxpayer Support

Successive governments in Ontario have increasingly relied on taxpayer-funded support to manage electricity rates. Subsidy programs of various kinds arose and then changed, with the first major change occurring with the Fair Hydro Plan in 2017, which then developed into the Ontario Electricity Rebate of 33.2 percent in 2020 (OEB 2020a). In response to the pandemic, the government implemented additional programs as well as suspending time-of-use pricing – thus increasing the rate subsidies further (OEB 2021b). In the November 2020 budget, the province again shifted how taxpayers provide support by covering 85 percent of the green energy component of the GA through the Comprehensive Electricity Plan, lowering costs for businesses and meeting its policy commitment to having residential costs rise in line with inflation.

4 In its 2020 Annual Report, Hydro One points to $738 million in productivity savings since 2015, pointing to initiatives such as supply chain and fleet optimization, IT contract savings, and changes to customer call centres as examples of savings.

Figure 5: Ontario Electricity Prices and Taxpayer Support



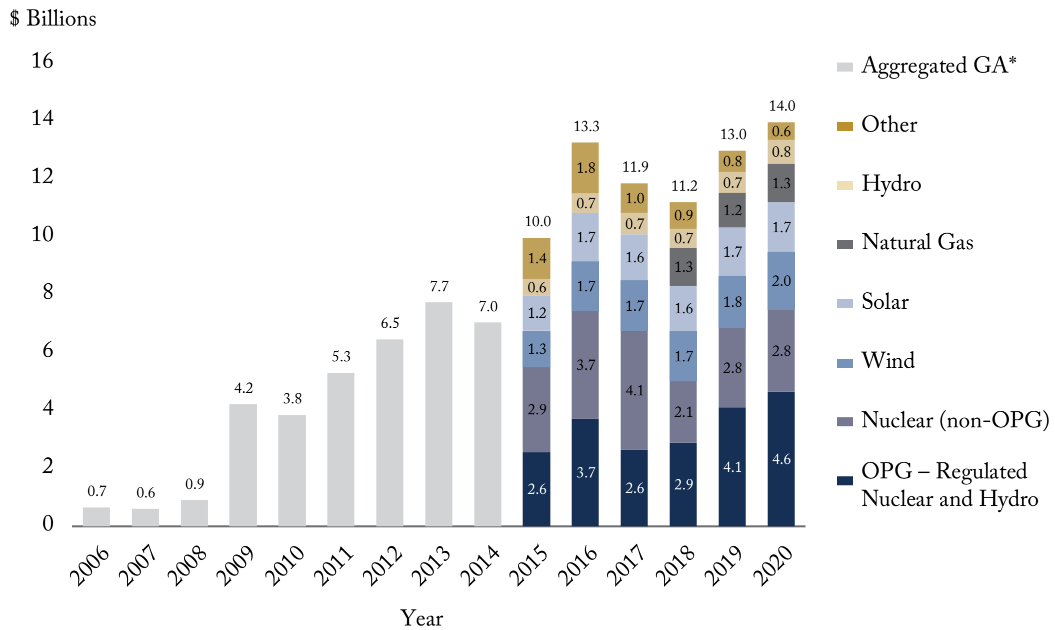
Note: Hourly Ontario Energy Price (HOEP) and Global Adjustment (GA) converted to Ontario fiscal year (March 31 year-end) from monthly costs reported by IESO and then converted to annual index.

Sources: Ontario government public accounts and expenditure estimates; Ontario Independent Electricity System Operator (IESO).

The inception of the Fair Hydro Plan on July 1, 2017 coincided with both the initial increase in subsidies and the substantial drop in the Ontario residential electricity price index (Figure 5).[5] However, rising energy costs coupled with a political desire to keep rates low have caused the rate subsidies to soar to levels far higher than in previous years. At the start of the 2021/22 fiscal year, with the introduction of the Comprehensive Electricity Plan, the province allocated $6.5 billion to consumer subsidies (Ontario 2021). The result is that residential ratepayers have enjoyed rates in 2020 as low as they were in the 2013/14 fiscal year whereas the cost to taxpayers has never been bigger.

5 In 2017, the Ontario government introduced a refinancing program without an apparent fiscal cost that, after partly causing the Auditor General to question the accuracy of the financial statements of the province, the subsequent government converted into an explicit taxpayer-financed subsidy.

Figure 6: Global Adjustment by Components



* Global adjustment data by components are only available from 2015 onwards. The aggregated total global adjustment is shown from 2006 to 2014.

Source: IESO. Global Adjustment Report.

The Global Adjustment Continues to Grow for All Types of Energy

The GA represents the difference between the revenues generators receive through long-term fixed power contracts and the revenues they collect in the wholesale market. It now accounts for the largest share of system cost growth since 2006. The GA has increased from $700 million in 2006 to $14 billion in 2020 – representing a 1,900 percent increase (Figure 6).

All generation in Ontario receives out-of-market payments through the GA, with nuclear and hydro making up the largest share as shown in Figure 6. In 2020, Ontario Power Generation's (OPG) share of the GA revenues for its nuclear and hydro energy amounted to $4.6 billion; non-OPG nuclear represented $2.8 billion; wind was $2 billion; solar was $1.7 billion; natural gas generation was $1.3 billion; non-OPG hydro was $800 million; and the remainder of the GA categorized as "other" was $600 million.[6]

6 Unfortunately, comparable data on production and generation capacity are not readily available to produce measures of the unit cost of GA components.

Policy Solutions

The government should look to find savings in the cost of energy and look to find further savings across the electricity distribution system, thus building on the savings Hydro One found after its privatization.

Assigning Global Adjustment Costs Efficiently

By creating the right price signals for consumers to reduce electricity consumption during the periods of highest costs, the province can reduce the need for costly peak-period production when extra supply must be provided to meet demand. Aggregate system costs can also fall if consumers increase their demand during periods of low cost.

Residential and small business consumers are subject to prices set by the OEB based on an estimate of the cost of supply for such regulated consumers. These regulated prices, broken into blocks of time during the day, roughly correspond to the system cost in given hours.

There are more accurate ways of assigning costs, therefore reducing consumption during high-cost hours and overall system costs (Bishop, Schaffer and Ragab 2020). One option is to set a price that reaches very high levels only during times of market stress, known as critical peak pricing. Another option, increasingly viable with the rise of smart home heating systems and electric vehicles, is to allow grid operators to reduce consumption by these kinds of uses during periods of high system costs. In both cases, the result would be lower costs overall for residential and small business consumers and lower system costs. These steps would reduce consumption when capacity is most costly to procure. Adding either price option for consumers could lower system costs.

There are two groups of industrial and large commercial consumers. Large consumers (so-called Class A consumers) that are part of the Industrial Conservation Initiative (ICI) can reduce the annual GA component of their electricity bill by reducing or eliminating their electricity consumption during the year's five hours of peak demand. Smaller industrial and commercial customers (Class B consumers) have their hourly GA component set at the end of the month. That end-of-month $/MWh amount applies to all consumption of electricity, regardless of the system costs in any given hour.

The industrial electricity pricing system does not lead to the efficient or fair allocation of costs in the system. Class A consumers face an overly high cost for power during peak hours and aren't sufficiently rewarded for reducing their electricity usage during the top five demand hours of the year. The ICI allows an industrial facility to avoid the GA portion of its bill based on reducing its share of power during the five hours with the greatest demand during a given year, which are not known in advance. If a customer used power during those peak hours, the cost was approximately $110,000/MWh in 2019. This is far above the cost of installing added capacity (Dachis and Bishop 2020). With such excessive costs around peaks, the ICI contributes to increased volatility for directly connected industrial loads as certain consumers reduce their consumption in far more hours than those that end up being the top five consumption peaks.

The IESO should instead create, initially as a pilot to test market interest, a demand response auction into which ICI customers would make offers for the price in return for curtailing their power consumption when the system is at capacity. This would create a market-based "interruptible rate" for ICI-eligible customers.[7]

7 Hydro-Québec, for its part, offers large customers credits in exchange for curtailing electricity consumption at its request. https://www.hydroquebec.com/business/customer-space/rates/interruptible-electricity-options-large-power-customers.html

ICI-eligible customers could get a lower fixed rate based on the amount of the demand they offer into the demand response market. Such a system would better align the prices industrial consumers pay with the system costs, while also preserving industrial competitiveness. Such a system would create a market-based signal for consumers to invest in electricity storage systems rather than the current arbitrary administrative rules in the ICI.

For smaller industrial and commercial consumers, the immediate solution is to have the IESO set the GA on an hourly basis. Without such time varying charges many industrial and commercial consumers lack incentive to smooth their power consumption. Smoothing load saves costs for the system by reducing the need for additional capacity to meet peak demand. An hourly GA rate would encourage price-sensitive manufacturers to push production to early mornings to avoid high-use, high-system-price afternoons and evenings. The OEB (2016) is examining such a system and should introduce a pilot pricing program for willing customers.

Regulatory Empowerment

The Ontario government's hands-on approach to energy procurement with little restraint has long been the center of controversy. The OEB does not have sufficient regulatory review powers to provide a check on government direction of the sector (Auditor General of Ontario 2011).

In 2004, the province established the Ontario Power Authority (OPA), which had a broad mandate under which it was responsible for forecasting supply and demand, assessing long-term adequacy, procuring capacity for the province, and overseeing conservation programs. The OPA signed contracts mostly with natural gas generators at first then renewables that led to the high cost of these generating facilities today, albeit with a few versions of procurement having a competitive process.

The trend towards increasing ministerial powers continued with the enactment of the *Green Energy Act* in 2009, which granted additional powers to the Ministry of Energy (Government of Ontario 2009). The *Act* is most well-known for the introduction of the feed-in-tariff that allowed all renewable power the right – up to a fixed total capacity – to connect to the grid and receive a generous fixed rate for their power (Vegh 2020). This led to an influx of renewables, with commensurately high costs, while system planning and regulatory oversight took a back seat.

By the time the OPA merged into the IESO in 2015, it had over 33,000 contracts for generation with most contracts containing 20-year terms. The bulk of these contracts were for renewables, but also included other sources of power such as natural gas generation. Between 2005 and 2015, the Ministry of Energy issued more than 100 directives to the IESO (and previously the OPA) to procure energy without regulatory review (Trebilcock 2017).

Shifting the Decision-making Powers

The *Green Energy Act* was repealed in 2019, but the Ontario government's top-down approach to energy procurement has allowed ministerial directives to shape the grid while largely being devoid of regulatory oversight. Renewable energy is not to blame for the cost increases, but rather it is the framework used to procure the energy. Unfortunately, the burden of these short-sighted decisions falls on future ratepayers and taxpayers (Alberta has shown a better way to reduce renewable costs through better design of long-term contracts – see Box 1). One remedy to mitigate costly policy errors going forward is to limit political interference from system planning and energy procurement. Governments often make choices based on a broad set of criteria in their overall policy goals. Legislation is the right forum for socio-economic goals. Implementation should then be

Box 1: A Better Way to Procure Green Energy

The Alberta government launched the Renewable Electricity Program (REP) in 2017 with the goal of bringing additional renewable electricity online. Unlike Ontario's feed-in tariff program, the REP utilized competition as a driving force in procurement. Three competitive auctions for a fixed amount of capacity were held between 2017 and 2018 in which the lowest cost offers won. This not only incents the lowest-cost generation to be built first, but has the added benefit of price discovery. The average price for wind contracts was $37/MWh (Hastings-Simon & Shaffer 2021). These 20-year contracts were "contracts for differences" meaning when market prices are higher than $37/MWh the government receives the difference, and if prices are below the government pays it. To date, the government has earned money as the generation-weighted price since inception is slightly over $38/MWh. In addition to this, the contracts awarded through the REP auctions stipulated that wind farms surrender their right to receive carbon offsets – thus translating to additional cost savings.

left to independent agencies. That should leave regulators with the sole priority of seeking economic efficiency (Church 2017).

The IESO, if subject to appropriate regulatory review by the OEB, is far better equipped than the government for making decisions on the most economical means of procuring electricity. However, the OEB does not currently have the power to review the IESO procurement process or government decisions. Such review powers could reduce the risk of Ontario repeating past mistakes in procurement and could provide the same benefit to other provinces, as exemplified by Site C in B.C. or Muskrat Falls in Newfoundland and Labrador where regulators were sidelined (Goulding 2019). The Ontario government can also mitigate risk to ratepayers by creating a competitive group of buyers of electricity, not just relying on the IESO (Goulding 2013). In such a system, LDCs would take part in buying groups that each forecast demand in areas they serve. Such load-serving entities would reduce the aggregate risk of contracting and supply on ratepayers. Risks would be shared with the shareholders of companies serving customers. These load-serving entities could take part in an IESO-operated, and OEB-regulated, contract market as recommended by Shaffer (2019).

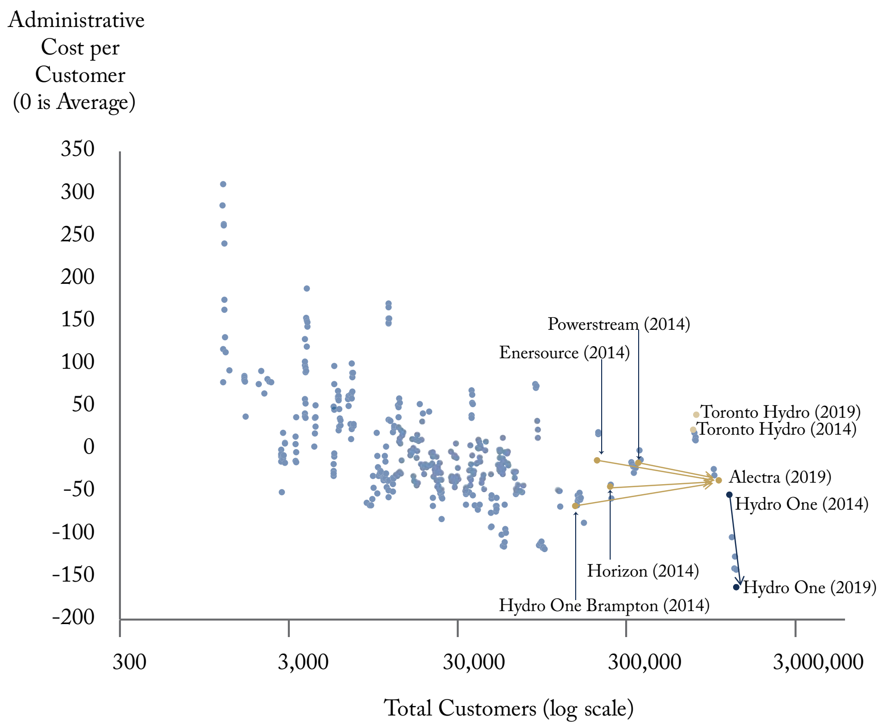
Reducing Distribution Costs

One solution for reducing distribution system costs is for the province to enact tax changes that allow cities to find outside investors who can reduce costs while also unlocking value for municipal taxpayers. Another solution is to find other ways to encourage LDCs to find savings through scale economies.

Seeking Scale Economies from the Smallest LDCs

Figure 7 plots each LDC's adjusted administrative costs per customer against the number of customers of that LDC from 2014 to 2019. There are scale economies in LDCs – to a point. The very smallest LDCs have

Figure 7: Relative Administrative Cost By Size of Customer Base, 2014-2019



Note: Relative administrative costs is calculated from regression analysis that controls for year-specific effects and the density of customers per square km of service. Methodology is the same as in Garner, Fyfe, and Vegh (2013). By regressing out the relationship between customer density and administrative costs per customer, this leaves a residual that, by definition, is unexplained by customer density.

Sources: Ontario Energy Board electric utility yearbooks; author's calculations.

administrative costs per customer that are $300 or more than the average LDC over this period.[8] If these smallest LDCs merged to take advantage of scale economies, they might find significant per-customer savings. However, these small LDCs have few customers. Thus, the savings would not be material system wide.

Further, there do not appear to be scale economies in administration for municipally owned LDCs beyond 300,000 customers. For example, Toronto Hydro, with about 780,000 customers as of 2019, has higher administrative costs than average and has seen rising administrative costs per customer since 2014. The merger to create Alectra (announced in 2015) also shows this. Compared to the 2014 weighted administrative costs per customers of its constituent companies (Powerstream, Horizon, Enersource, and Hydro One Brampton) of $138, administrative costs per customer of the new company went up to $143 by 2019.

8 Administrative costs are adjusted to control for the higher costs of LDCs that cover a wide area. An LDC's administrative costs per customer are positive if they have higher costs than an LDC of average customer density, and negative if costs are below average. This methodology follows that laid out in Fyfe, Garner and Vegh (2013).

Seeking Private Investment in Municipally Owned LDCs

There was one major LDC that saw private investment over this period: the distribution arm of Hydro One. It saw the largest administrative cost savings per customer over this period of $90 per customer. That amounted to a 37 percent savings on each Hydro One customer's $244 share of 2014 administrative cost. Private investors, beginning in 2015, have likely brought in cost discipline to Hydro One, something the merger to form Alectra did not see.

What if all the rest of Ontario's LDCs followed this route and saw similar 37 percent administrative savings per customer? Using 2019 data, administrative costs now at about $650 million would fall by $239 million, saving customers $61 per year in LDC administrative costs. Total system-wide, municipal-owned LDC costs were about $2 billion, so private investment could shave about 10 percent of these costs.

For the province to enable local governments to find similar administrative savings through private investment, it should eliminate a series of LDC-specific taxes (Garner, Vegh and Fyfe 2013). It should eliminate the payments-in-lieu-of corporate-taxes (PILs), which collect the equivalent of both federal and provincial corporate income tax for the province. It should also eliminate a departure tax akin to a capital gains tax on leaving the PILs regime. The province should also eliminate a transfer tax it levies of 22 percent on the value of the assets sold. These taxes were intended to ensure the province had a financial backstop for provincial stranded debt from the 1990s in case electricity assets left public ownership. Now that the debt has been whittled down with PILs collected for decades from LDCs, Hydro One and Ontario Power Generation, there is no reason for a tax on these grounds.

What is the argument for keeping LDCs in public ownership? There should be a clear policy objective such as correcting a market failure or filling a void in the market.[9] In the context of an electricity system, the most obvious market failure are the natural monopolies for distribution and transmission. Correcting these market failures requires strong rate regulation – not government ownership. Private investment alleviates risk that taxpayers would otherwise face and brings a stronger incentive to reduce controllable costs.

Cities too would see a windfall benefit, with estimates of municipal equity value of between $11 and $14 billion (Robins 2017). Cities could turn equity stranded in LDCs into needed infrastructure such as transit, roads, or sewers.

Reducing Reliance on Taxpayer Support

As system costs – particularly in energy generation – have continued to rise, the Ontario government has increasingly turned towards taxpayers to keep total bills down. The most recent estimates from the Ministry of Finance show the cost of subsides rising to a staggering $6.5 billion for the 2021/22 fiscal year – or nearly 3.5 percent of total government expenditures. To put this number in context, that same budget proposed to spend $5.8 billion in taxpayer dollars on long-term care. The total budget for transportation is less as well, at $6.2 billion. This approach is unsustainable in the long term and may further increase costs. The effect of taxpayers

9 Many jurisdictions across North America (including Ontario) have shown that private investors are willing to invest in these segments of the market indicating no void in the market.

subsidizing costs is that consumers are responding by using more electricity than they otherwise would have. Total system costs will increase as a result of price mitigation.[10]

Starting in 2021, a large share of the taxpayer support will go towards reducing the GA. Residential and small business consumers will see a commensurate reduction in their taxpayer subsidy provided through on-bill rebates. However, they will still enjoy a considerable amount of on-bill taxpayer subsidy. The policy rationale for taxpayers financing the green energy component of the GA is that policy decisions made for non-market energy reasons should be financed outside of the energy system. This partly justifies the subsidy amount announced in the 2020 Ontario budget. It is economically justified because Ontario businesses that compete globally with companies that pay market-set prices do not need to shoulder politically motivated decisions on energy procurement. On-bill subsidies over and above this amount have little justification, and should be phased out. Residential subsidies are more politically motivated. There are various ways to reduce this subsidy in a politically palatable way, such as by as making it means-tested or applicable only up to a certain amount of consumption.

Conclusion

Ontario's system cost grew from $12 billion in 2006 to $21 billion in 2019 while demand has fallen by 10 percent over the same period. The cost of energy has been the largest driver of system cost growth. As costs continue to mount, the Ontario government increasingly relies on taxpayers to help foot the bill likely contributing to the rise in system costs.

The Global Adjustment has grown dramatically and high energy costs are the cause of recent price spikes. The short-term solution to this problem is to focus on better price signals and risk allocation for all kinds of customers to keep costs down. Long-term solutions to reduce energy costs require systemic change. The Ontario government should end its hands-on approach to system planning and procurement. Instead, the Ontario government should provide high- level policy direction that focuses on both empowering the OEB to regulate and ensuring the independence of the IESO to avoid repeating past mistakes.

To encourage further system cost reductions, the province should encourage LDCs to find savings. One solution is for the province to enact tax changes that allow cities to find outside investors who can reduce costs while also unlocking value for municipal taxpayers. Lastly, the province should eliminate subsidies over and above what covers the green energy component.

10 Exploring the effect of the electricity price mitigation on electricity consumption is beyond the scope of this paper.

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