Ontario Industrial Electricity Rate Study

prepared for the Canadian Manufacturers & Exporters by London Economics International LLC

October 22nd, 2019[1]

London Economics International LLC ("LEI") was retained by the Canadian Manufacturers & Exporters ("CME") to conduct an industrial electricity rate study in Ontario. LEI focused on four key areas: a review of the current system in place for industrial rates in Ontario; a comparison of industrial rates in Ontario to a selection of comparator jurisdictions; a qualitative commentary on the options available to make rates more competitive; and a quantification of the economic impact a targeted industrial rate cut would have on the Ontario economy. Based on LEI's analysis, rates for Class A and Class B customers are higher than the selected group of North American jurisdictions, but Class A customers with best load shifting outcomes face rates that are more competitive with the comparator jurisdictions. For larger Class B customers and those Class A customers that have less ability to shift load but run energy-intensive operations and are trade exposed, the government should consider developing options that address the higher rates they face. A properly designed Industrial Rate Relief Initiative could benefit industrial consumers and have a wider positive indirect and induced impact on the provincial economy. Such programs should be targeted, time-limited, and commitment linked in order to better optimize outcomes.

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List of acronyms

AMPCO	Association of Major Power Consumers in Ontario
BEE	Federal Association for Renewable Energy ("Bundesverband Erneuerbare Energien")
CBR	Capacity Based Recovery
CILRB	Competitive Investment Linked Rate Buydown
CME	Canadian Manufacturers & Exporters
ComEd	Commonwealth Edison
DFC	Distribution Facilities Charge
DRC	Debt Retirement Charge
DTE	DTE Electric Company
ECR	Energy Cost Recovery
EEG	Renewable Energy Act ("Erneuerbare Energien Gesetz")
EIA	U.S. Energy Information Administration
ENDM	Ministry of Energy, Northern Development, and Mines
FIT	Feed-In Tariff
GA	Global Adjustment
GDP	Gross Domestic Product
GDR	German Democratic Republic
GPP	Gross Provincial Product
GS	General Service
HOEP	Hourly Ontario Energy Price
HQ	Hydro Quebec
I/O	Input-output
ICI	Industrial Conservation Initiative
IEDT	Illinois Electricity Distribution Tax Charge
IESO	Independent Electricity System Operator
IMPLAN	Impact Analysis for Planning
IRRI	Industrial Rate Relief Initiative
ITA	Interim Income Tax Rate Adjustment
kVA	Kilovolt-Ampere
kWh	Kilowatt Hour
LDC	Local Distribution Company
LEI	London Economics International LLC
LIEAF	Low Income Energy Assistance Fund
MISO	Midcontinent Independent System Operator
MKD	Maximum Kilowatts Delivered
MWh	Megawatt Hour
NAICS	North American Industry Classification System
NDR	Natural Disaster Reserve
NIER	Northern Industrial Electricity Rate
NIPSCO	Northern Indiana Public Service Company
NYPA	New York Power Authority
OEB	Ontario Energy Board
OEFC	Ontario Electricity Financial Corporation

OER	Ontario Energy Report
OPA	Ontario Power Authority
OPG	Ontario Power Generation
PDF	Peak Demand Factor
REC	Renewable Energy Credit
RNY	ReCharge New York
RPP	Regulated Price Plan
SAM	Social Accounting Matrix
TWh	Terawatt Hour

1 Introduction

London Economics International LLC ("LEI") was retained by the Canadian Manufacturers & Exporters ("CME") to conduct an independent study on industrial electricity rates for Ontario's manufacturing sector. The scope of work consisted of:

- review of Ontario industrial electricity rates and estimation of proxy customer bills in 2018;
- assessment of competitive electricity rate levels and bills based on a comparison with a selected group of jurisdictions;
- development of options to change rates in a manner consistent with rate setting principles that is beneficial to industrial consumers and the Province;
- quantification of economic benefits from a rate reduction targeted at industrial customers; and
- consultation with relevant industry and government officials/experts throughout the project.

A challenge for this engagement was to settle on a definition of what constitutes an "industrial" rate, particularly given the diverse interests of CME's broad membership. For the purposes of this paper, LEI defines industrial as medium to larger load customers that operate in the production of products. Ontario's industrial customers operate in areas such as iron and steel, chemicals, motor vehicle manufacturing, metal ore mining, pulp and paper, and refineries, among others.[2] Industrial customers make up a sizable portion of Ontario's total Gross Domestic Product ("GDP"), with those involved in manufacturing making up around 12% of GDP, and those involved in mining, quarrying, and oil & gas making up around 1%. Aside from this direct contribution, they in turn support additional economic activity in the province. Electricity costs for these customers can form a sizable portion of their operating expenses due to their production process, and a large portion of their business can depend on sales outside of Ontario.

LEI is an independent economic consulting firm, not an advocacy group. Consequently, LEI analysis is based on key principles of regulatory economics, including cost causation, incentives compatibility, non-discrimination, economic efficiency, transparency, and administrative simplicity.

1.1 Brief description of CME

From the first industrial boom in Canada, CME has been advocating for and representing member interests. Nearly 150 years strong, CME has earned an extensive and effective track record of working for and with 2,500 leading manufacturers from coast to coast to help their businesses grow. The association directly represents more than 2,500 leading companies nationwide. More than 85% of CME's members are small and medium-sized enterprises. As Canada's leading business network, CME, through various initiatives including the establishment of the Canadian Manufacturing Coalition, touches more than 100,000 companies from coast to coast, engaged in

[2] Examples of larger load customers that are not industrial (i.e. not the focus of this paper) include hospitals, large office complexes, and university campuses. The boundary for a "large" customer is generally around the 5,000 kW mark.

manufacturing, global business and service-related industries. CME's membership network accounts for an estimated 82% of total manufacturing production and 90% of Canada's exports.

While CME supports this independent study, the association does not directly support or endorse any of the recommendations of the report. Additionally, the Association of Major Power Consumers in Ontario ("AMPCO") was not involved in the funding of this study and does not directly support or endorse any of these recommendations.

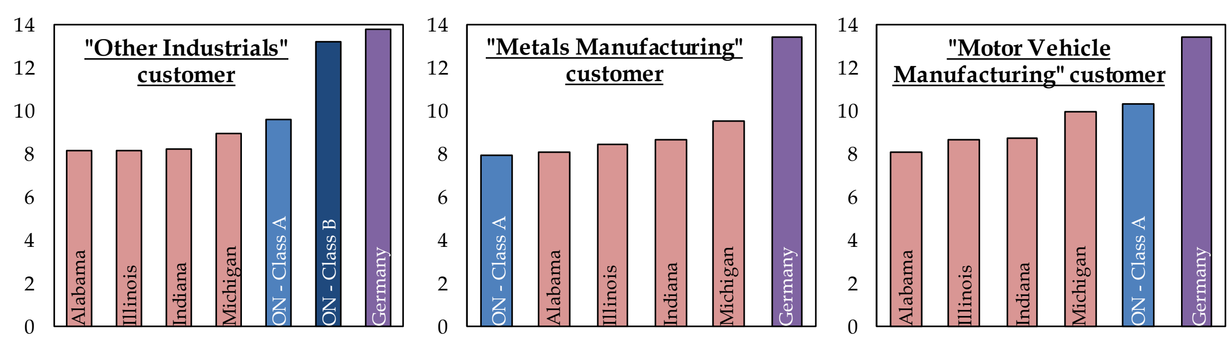
1.2 Executive summary

Rates for many industrial customers in Ontario are among the highest in North America. LEI reviewed rates in four case study jurisdictions (Alabama, Illinois, Indiana, and Michigan) chosen in consultation with CME to represent the sources of products competing with Ontario manufacturers. LEI also examined rates in Germany to provide a broader international context.

Rate comparisons depend on a number of factors, including tax treatment, as well as assumptions around customer types and sizes. For example, using the Energy Information Administration's average rates for industrial customers in 2018 (which includes taxes) in the comparator North American jurisdictions, and comparing those to Ontario's average rates (with taxes added in), Ontario's Class A rates were 22% higher than the average of the comparator jurisdiction rates, while Ontario's Class B rates were 75% higher.[3]

Using a bill build-up approach and proxy customer load profiles for the North American comparison, LEI found that, for customers not participating in load management programs in Ontario, rates were noticeably higher than in Michigan, the highest cost jurisdiction among the US states studied (as shown in Figure 1). The increase in rates since 2007 was also highest in Ontario for such customers relative to the case study states, although some states also saw significant increases. While published rates for industrial consumers in Germany are similar to or higher than those in Ontario depending on customer class, Germany also has a number of negotiated rate programs which mean that actual rates are lower.

Figure 1. Summary of proxy customer rates by jurisdiction (2018, cents per kWh)



Note: See Sections 2 and 3 for background, assumptions, and context to these summary figures

[3] Class A customers are those that participate in the Industrial Conservation Initiative; Class B customers are those who do not. US rates converted to Canadian dollars using an exchange rate of US$1 to CAN$1.3.

The significant price differences for electricity between Ontario and competing jurisdictions result in a competitive disadvantage, particularly for those customers who are trade exposed and for whom electricity is a large proportion of input costs. While there are many aspects to competitiveness, including not just electricity costs but also elements like health care expenses, tax rates, work force training initiatives (to name but a few), managing perceived high electricity prices is important to improving Ontario's ability to compete. This does not mean that electricity prices for all consumers need to be brought to levels equal to or below those of competing jurisdictions. However, it does require a thoughtful look at ways in which the impact of electricity rates on the most impacted businesses can be managed.

The main components of an industrial customer's monthly electricity costs relate to commodity, delivery, and regulatory charges. In Ontario, monthly commodity component costs make up the largest portion of customer bills, with the Global Adjustment ("GA") portion specifically making up among the largest portions of most customer bills. Based on LEI's cross-jurisdictional comparison, the GA is also the main reason why rates in Ontario are high for most industrial customers compared to other North American jurisdictions, both under Class A and Class B structures.

There are no easy solutions to reducing the GA. The GA is the cost net of wholesale market offsets of a wide range of commitments to electricity producers under contracts and regulatory arrangements. While the underlying contracts could be voluntarily renegotiated, they cannot otherwise be reduced without taking steps, such as abrogating contracts, which would have a negative impact on the investment environment in Ontario. Although some costs should be moved from the GA to the provincial budget, in particular those associated with policy drivers distinct from the provision of electricity, any such initiative would need to be appropriately limited to be mindful of other budget priorities.

Within Ontario, the Industrial Conservation Initiative ("ICI") allows customers that can successfully load shift to reduce the portion of their total monthly bills related to the GA substantially compared to the same customer under a Class B rate structure. Load shifting provides a benefit to the system by incentivizing reduced demand at coincident peaks. The ICI also allows some industrial customers in Ontario to have rates that are more competitive with other North American jurisdictions, by lowering their GA costs. As these customers generally run energy-intensive operations and are trade-exposed, for their products to be competitive within and outside Ontario, having rates that are more comparable to competing jurisdictions is important to their continued operations in the province.

However, other Class A customers that have less capability to load-shift, and all large Class B customers, face rates that are higher on average than most other North American jurisdictions (with larger Class B customers facing the worst competitive disadvantage). LEI's cross-jurisdictional comparison estimates that customers with greater flexibility who reduce their coincident peak demands can achieve rates more competitive with selected competing jurisdictions in North America, but for customers that have less load flexibility or are not under the ICI, their electricity costs would be highest in Ontario. This is particularly true for some large Class B customers.

LEI believes that no single program can address relatively high rates to industrial consumers. Instead, a portfolio approach is necessary. Consequently, LEI has put forward four initiatives. The first initiative is intended to provide greater price certainty by assuring that the government will avoid policies that further increase electricity costs. The remaining initiatives are intended to reduce costs for industrial consumers; in some cases, they are also applicable to all customers.

Collectively referred to as the Industrial Rate Reduction Initiative ("IRRI"), program elements include:

1. a commitment by the government to end uneconomic spending in the sector, to limit unnecessary additions to the GA going forward;
2. shifting funding for microFIT and higher cost FIT contracts from the GA to the provincial budget, to reflect the fact that such contracts were driven by policy mandates rather than the intrinsic needs of the sector. Based on publicly available FIT pricing data and assumptions around capacity factor, LEI has estimated the total cost of solar FIT and microFIT contracts at around $1.16 billion, with the GA cost of these contracts using 2018 wholesale prices estimated at $1.11 billion;
3. instituting a competitive investment linked rate buydown program, as given the size of the disparity between Ontario and competing jurisdictions, energy intensive and trade exposed customers may require additional assistance to reduce the differential with competing North American jurisdictions. This program is meant to provide material improvements for industrial customers most impacted by higher rates, and would be subject to certain commitments and clear time limitations. With an annual budget of $500 million, LEI believes meaningful amounts could be awarded to qualified participants. The more targeted the program, the higher the impact it would have on reducing rates for qualified participants; and
4. monetizing green attributes by creating a voluntary Renewable Energy Credit ("REC") program, which is essentially meant to allow companies that want to be labeled as "green" to compensate those that are focused on lowering costs.

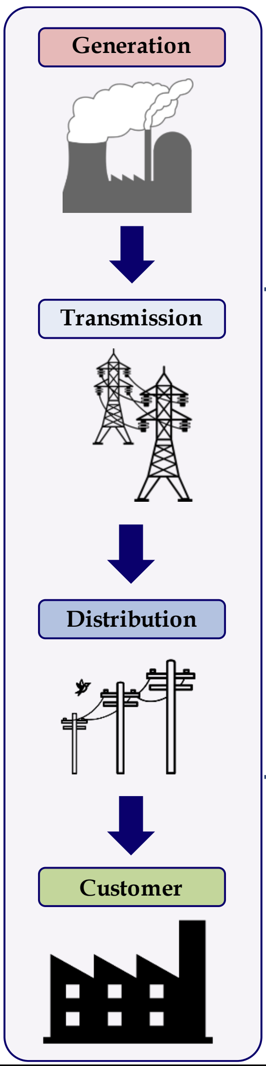
Where those items involve an investment of taxpayer funds above that required to fund policy-driven costs, as in the rate buy-down, LEI emphasizes that the program should be targeted, time-limited, and commitment linked. If done correctly and prudently, a decrease in industrial rates could have a net-positive impact on the province. For example, based on the assumptions and preliminary assessment of the IRRI as covered in Section 4, LEI estimated the collective benefit of these programs could be an annual rate reduction of $849.5 million for industrial customers. To assess the macroeconomic impact of a rate reduction of this level on industrial customers, LEI opted to use the Impact Analysis for Planning ("IMPLAN") economic input-output model, as further detailed in Section 5. Assuming a $849.5 million decrease in industrial electricity costs, and a diversion of spending by those customers towards productive activities, indicative results from the macroeconomic analysis suggest the gross direct, indirect and induced effects could be the creation of between 1,200 to 3,400 jobs, more labour income, and a total output increase ranging from $453 million to $972 million.

2 Status quo for industrial customers

2.1 Overview of electricity bill components

At a high level, the main components of an industrial customer's monthly electricity bill relate to the cost for the actual electricity over the course of a month, the cost for delivery of that electricity, and other costs such as regulatory. Electricity charges are meant to cover the cost of generating the power used by customers. Delivery charges are meant to cover the cost of flowing the power through transmission lines and then distribution lines for use by end customers (analysis will focus on distribution-connected customers). Regulatory charges are meant to cover costs such as administering the wholesale electricity system. Figure 2 provides a high-level overview of the main components of an electricity bill, which is expanded upon in Section 2.1.1 to 2.1.3 below, along with simplified examples of component calculations for illustrative purposes.

Figure 2. High-level overview of electricity bill components



1. Electricity component of bill

1. **Wholesale charges** are based on monthly consumptions (kWh) and monthly weighted average wholesale Ontario electricity market prices (in $/kWh)
   - Wholesale charges are generally similar across Local Distribution Companies ("LDCs")
2. **Global Adjustment ("GA")**
   a. For **Class A** customers, based on total system GA costs and customer's Peak Demand Factor
      - Class A GA charges are generally the same across LDCs
   b. For **Class B** customers, based on customer monthly consumption (kWh) and average GA costs in $/kWh
      - LDCs decide which one of the three GA rates consistently applies to its own customers based on its billing cycle; rates can therefore differ between LDCs on a monthly basis, but should average out to the same amount over longer periods of time

2. Delivery component of bill

- Includes line items for distribution, transmission, service charges, and various rate riders; line items and rates/charges vary based on customer's LDC, industrial customer's peak demand (which determines what service load size classification it falls under) and marginally based on Class A or Class B status
- Items are charged mostly based on peak demand (in $/kW terms), followed by flat dollar terms, and in some cases charges based on monthly consumption (in $/kWh terms)

3. Regulatory component of bill

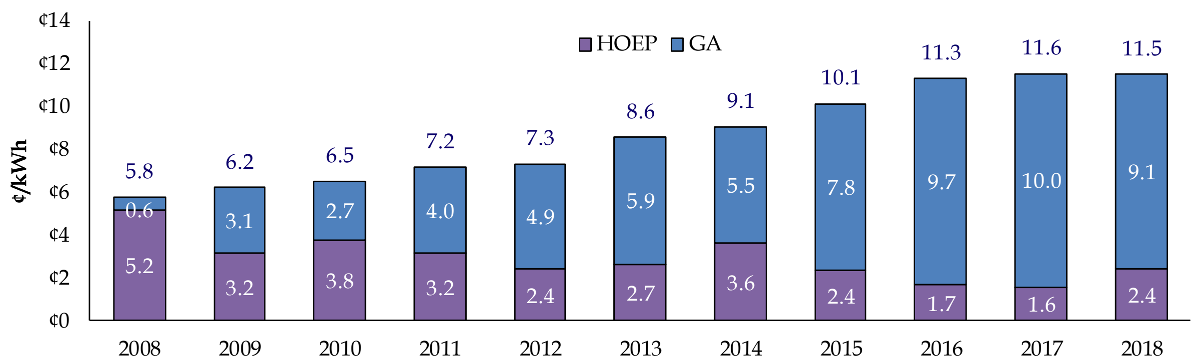
- Regulatory charges and line items are generally the same across LDCs and customer classifications. Charges are mostly in $/kWh terms

2.1.1 Electricity component

There are two components that form the basis for electricity commodity charges in Ontario: the Hourly Ontario Energy Price ("HOEP") and the GA. The HOEP is the wholesale market price and is based on supply and demand, as balanced in real-time for each hour. The GA reflects the difference between market prices/revenues and: 1) the regulated rate paid to Ontario Power Generation's ("OPG") baseload generating stations; 2) payments made to suppliers under contract with the Independent Electricity System Operator ("IESO"); and 3) contracted rates paid to non-utility and other resources.

The GA is also the mechanism used to recover the cost of a number of other IESO-administered programs, including demand response and conservation initiatives. Taken together, the HOEP and the GA reflect the price for the electricity component of a customer's bill in Ontario. The annual average HOEP and GA from 2008 to 2018 is presented in Figure 3 below.

Figure 3. Annual average HOEP and GA from 2008 – 2018



Source: IESO's "Average HOEP plus Average GA" datasheet; LEI forecasts for HOEP and GA available separately

As further discussed in Sections 2.1.1.1 and 2.1.1.2 below, how industrial customers pay for the GA component of their bills depends on whether they participate in the Industrial Conservation Initiative (Class A customers) or not (Class B customers). Charging for the wholesale component is generally very similar for both Class A and non-Regulated Price Plan ("non-RPP") Class B customers – a volumetric charge based on the customer's monthly kWh of consumption and the rates meant to reflect monthly weighted average HOEP.[4]

2.1.1.1 Class A customers

Class A customers are those that participate in the Industrial Conservation Initiative ("ICI"), which was introduced in 2010 as a method of reducing electricity demand during peak periods.[5]

[4] Class B customers are those that do not participate in the ICI. Class B RPP customers are those that pay time-of-use prices set by the OEB under the Regulated Price Plan (residential and general service customers with peak demands less than 50 kW). Non-RPP Class B customers are those that do not participate in the RPP, typically due to their larger load. Industrial customers would therefore most likely be either Class A or non-RPP Class B.

[5] See O. Reg. 429/04 under the Electricity Act (1998)

By successfully participating in the ICI, industrial customers can see a reduction in the GA portion of their electricity bills (compared to a status quo of not participating in the ICI).

Eligibility to participate in the ICI depends on average monthly peak demand over an annual period, as presented in Figure 4. Customers with an average peak demand greater than 5 MW are automatically entered into the ICI but can opt out if they choose, while eligible customers with average peak demands of greater than 0.5 MW to 5 MW can choose to opt into the ICI.[6]

Figure 4. Peak demand and ICI eligibility

Average peak demand (X)	Eligibility
X > 5 MW	All customers automatically entered, can opt out
1 MW < X ≤ 5 MW	All customers eligible, need to opt in
0.5 MW < X ≤ 1 MW	Certain customers eligible*, need to opt in

*applies only to customers with NAICS codes commencing with 31, 32, 33, or 1114 (manufacturing and greenhouse categories)

Source: O. Reg. 429/04 under the Electricity Act (1998)

Eligibility for the ICI depends on average monthly peak demand over an annual base period. Using the current billing period as an example, Figure 5 below presents the timing associated with Class A eligibility and participation. The key timeframes and periods for the most recently passed billing period were:

- The **annual base period,** which ran from May 1st 2017 to April 30th 2018. Monthly average peak demands over this period determined whether customers were Class A eligible;
- If a customer was eligible, they had until June 15th 2018 to either **opt out** (in cases where their average monthly peak demands were greater than 5 MW) or **opt in** (in cases where their average monthly peak demands were greater than 0.5 MW and less than or equal to 5 MW); and
- Those eligible customers that chose to participate in the ICI were billed as Class A customers for the duration of the adjustment or **billing period** which ran from July 1st 2018 to June 30th 2019.

Figure 5. Timing associated with ICI for current billing period

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017					Annual base period: May 1 2017 - April 30 2018							
2018					Opt in/out		Annual billing period: July 1 2018 - June 30 2019					
2019												

Source: IESO presentation. Industrial Conservation Initiative (ICI) Overview. April 5, 2018

[6] Refers to peak demand of one customer load facility, not the customer's aggregate load.

Class A customers pay for the GA based on their percentage share of demand at the top five Ontario peak demand hours over the base period, which is called their peak demand factor ("PDF").[7] For the 2017 to 2018 base period, Figure 6 presents a calculation of the PDF using the actual top five system peaks and an illustrative industrial customer's coincident peak demands during those peak hours.

Figure 6. Illustrative peak demand factor calculation for the 2017 – 2018 base period

Date and time	Illustrative load for customer X (MW)	System peak (MW)
September 25, 2017, hour ending 17	5.2	21,812
September 26, 2017, hour ending 17	5.3	21,665
June 12, 2017, hour ending 17	4.8	21,999
January 5, 2018, hour ending 18	4.1	20,885
July 19, 2017, hour ending 18	5.6	20,984
Total	**25 [X]**	**107,344 [W]**
Peak Demand Factor: [X] / [W]		**0.000232894**

Source: System peak demand data is from the IESO's website

Class A customer PDFs are multiplied by the monthly total system-wide GA costs (in dollar terms) to get the GA charge that shows up on their monthly bills. Using the PDF established in Figure 6 and the actual monthly GA costs from July to December 2018, Figure 7 presents a calculation of the GA portion of an illustrative industrial customer's monthly electricity bill.

Figure 7. Illustrative estimation of Class A customer's monthly GA costs

		Jul-2018	Aug-2018	Sep-2018	Oct-2018	Nov-2018	Dec-2018
Total GA costs for month ($ million)	**[Y]**	$ 911.8	$ 876.4	$ 847.3	$ 1,135.3	$ 936.4	$ 853.2
Peak demand factor	**[Z]**	0.000232894					
Customer X's monthly GA charge ($)	**[Y] * [Z]**	$212,353	$204,109	$197,331	$264,405	$218,082	$198,706

Source: Monthly total GA costs are from the IESO's "GA components plus costs and consumption by customer class" datasheet

2.1.1.2 Class B customers

Industrial customers that do not meet ICI eligibility criteria, choose not to opt in, or choose to opt out of the ICI, are considered Class B customers for billing purposes. They pay for the GA portion of their bill based on their monthly consumption (in kWh) and the monthly GA value (in ¢/kWh) as published by the IESO. The IESO publishes three GA rates – the 1st estimate, the 2nd estimate, and the Actual – with each local distribution company ("LDC") deciding which one consistently applies to its own customers based on its billing cycle. Differences between these rates are summarized in Figure 8, and are centered around when they are published. Because the 1st and

[7] According to the IESO, the top five peak demand hours for the purposes of the ICI are those occurring on different days in which the greatest number of MW of electricity were withdrawn from the IESO-controlled grid by all Ontario market participants, including the impact of embedded generation. Source: IESO presentation. *Industrial Conservation Initiative (ICI) Overview*. April 5, 2018

2nd estimates rely in whole or in part on forecast data, they also include true-ups to account for differences from actuals.

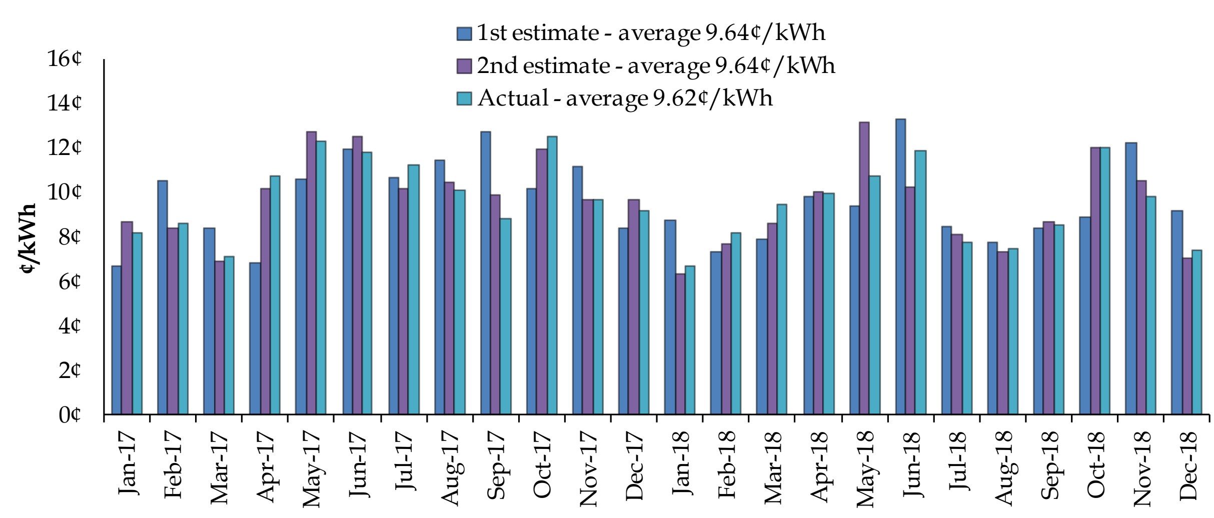
Figure 8. Differences between Class B GA rates

GA rate	When data published relative to month it applies to	Basis for calculation	True-ups
1st estimate	Last business day of preceding month	Based on forecasts and estimates for demand and GA cost data	True-ups included in monthly rate to account for difference between previous month's 1st estimate and previous month's Actual GA rate
2nd estimate	Last business day of month it applies to	Based on combination of actual demand and cost data (when available) and forecasts/estimates (when actual data is not)	True-ups included in monthly rate to account for difference between previous month's 2nd estimate and previous month's Actual GA rate
Actual	Tenth business day of following month	Based on actual demand and GA cost data	No true-up required since based on actual data

Source: IESO website. *Global Adjustment for Mid-sized and Large Businesses*

Although the values for these GA rates differ from each other on a monthly basis, they should average out over longer periods of time. Figure 9 presents the monthly GA rates for the 1st estimate, 2nd estimate, and the Actual for 2017 and 2018, as well as their averages over that timeframe.

Figure 9. Monthly Class B GA rates for 2017 - 2018



Source: IESO's "GA ¢/kWh" datasheet

The GA charges seen on a Class B industrial customer's bill therefore only depend on its total monthly consumption (in kWh), and not on when it consumes (which is the case with Class A customers). Figure 10 shows the monthly GA charges for an illustrative Class B customer from July to December 2018, based on whether its LDC uses the 1st estimate, the 2nd estimate, or the Actual GA rate.

Figure 10. Illustrative estimation of Class B customer's monthly GA costs

		Jul-2018	Aug-2018	Sep-2018	Oct-2018	Nov-2018	Dec-2018
Customer's monthly consumption (kWh)	[D]	950,000	944,000	959,000	954,000	956,000	960,000
GA - 1st estimate ($/kWh)	[E]	$ 0.085	$ 0.078	$ 0.084	$ 0.089	$ 0.122	$ 0.092
GA - 2nd estimate ($/kWh)	[F]	$ 0.081	$ 0.073	$ 0.087	$ 0.120	$ 0.105	$ 0.071
GA - Actual ($/kWh)	[G]	$ 0.077	$ 0.075	$ 0.086	$ 0.121	$ 0.099	$ 0.074
monthly GA charge under 1st estimate billing ($)	[D] * [E]	$ 80,750	$ 73,538	$ 80,748	$ 85,097	$117,014	$ 88,320
monthly GA charge under 2nd estimate billing ($)	[D] * [F]	$ 77,140	$ 69,101	$ 83,049	$114,480	$100,762	$ 67,872
monthly GA charge under Actual billing ($)	[D] * [G]	$ 73,530	$ 70,706	$ 82,282	$115,052	$ 94,262	$ 71,040

2.1.2 Delivery component

The second component of industrial customer bills are the delivery charges. These charges vary between LDC service territories, based on a number of factors including LDC service territory size and location, customer density, the age of utility assets, and any new build requirements. Within LDCs, delivery charges differ based on consumer classification. For the purposes of this study, LEI focused on two classification types: General Service ("GS") within the 50 to 4,999 kW range; and Large Use (for customers whose peak demands are greater than or equal to 5,000 kW).

Delivery charges for individual LDCs are approved by the OEB, and generally consist of a fixed dollar amount service charge, a distribution volumetric rate (in $/kW terms), retail transmission rates (in $/kW terms), and various rate riders that differ between utilities. Transmission rates are meant to cover the costs LDCs pay for the transmission of electricity over high-voltage lines (controlled by transmission utilities such as Hydro One) to lines that the LDCs operate. Distribution rates are the charge related to the actual delivery of electricity over LDC-operated wires to the LDC's customers. Service charges are meant to cover other utility costs such as metering, billing, customer service, and other general operations. Finally, rate riders are variable charges/credits meant to recover/refund various accounts.

An industrial customer's delivery rates, charges, and line items may therefore vary based on its LDC service territory (each with its own rates), load size (e.g. GS or Large Use), and marginally based on classification (Class A or B). These differences are explored further in Section 2.2. As a simplified example, Figure 11 presents condensed delivery rates for an Alectra GS (500 to 4,999 kW) Class B customer in the Enersource Rate Zone for 2018. As rates in this example are charged in different terms ($/kW, $/kWh, and fixed $ terms), these rates were applied to a hypothetical industrial customer with a peak demand of 2,000 kW and a monthly consumption of 1,000,000 kWh to get its delivery charges for that month.

Figure 11. Illustrative estimation of Class B customer's delivery charges

Customer demand profile		Amount	Unit
Customer's peak demand	[C]	2,000	kW
Customer's monthly consumption	[D]	1,000,000	kWh

Delivery rate/charge		Amount	Unit	Calculation method	Customer charge ($)
Service Charge	[E]	$1,764.42	$	[E]	$1,764.42
Distribution Volumetric Rate	[F]	$2.3994	$/kW	[F]*[C]	$4,798.80
Retail Transmission Rate - Network Service Rate	[G]	$2.6436	$/kW	[G]*[C]	$5,287.20
Retail Transmission Rate - Line and Transformation Connection Service Rate	[H]	$2.4803	$/kW	[H]*[C]	$4,960.60
Low Voltage Service Rate	[I]	$0.0784	$/kW	[I]*[C]	$156.80
Three separate rate riders charged in $ terms	[J]	$71.83	$	[J]	$71.83
Six separate rate riders charged in $/kW terms	[K]	($0.12269)	$/kW	[K]*[C]	($245.38)
One rate rider charged in $/kWh terms	[L]	($0.0005)	$/kWh	[L]*[D]	($500.00)
				Monthly delivery charge for customer	$ 16,294.27

Note: Rates and charges for an Alectra General Service Class B customer in the Enersource Rate Zone for 2018
Source: Alectra's Decision and Rate Order for 2018

2.1.3 Regulatory component

The third component of an industrial customer's electricity bill relates to regulatory charges. Regulatory charges are generally the same across the different LDCs (and within LDCs across different load size classifications), with the largest item being the Wholesale Market Service Rate (meant to cover costs such as market regulation and wholesale electricity system administration). Figure 12 below shows the various components of regulatory charges included as part of 2018 LDC rates. These rates were applied to a hypothetical industrial customer with a monthly consumption of 1,000,000 kWh to get its regulatory charges for that month. One charge, the Capacity Based Recovery, is only applicable to Class B customers.[8] Therefore, Figure 12 shows the regulatory component for this hypothetical customer if it were Class A or Class B.

Figure 12. Illustrative estimation of Class A and B customer's delivery charges

Customer demand profile		Amount	Unit
Customer's monthly consumption	[D]	1,000,000	kWh

Regulatory rate/charge		Amount	Unit	Calculation method	Customer charge ($)	
					Class A	Class B
Wholesale Market Service Rate	[E]	$ 0.0032	$/kWh	[E]*[D]	$ 3,200	$ 3,200
Capacity Based Recovery *(Applicable for Class B Customers)*	[F]	$ 0.0004	$/kWh	[F]*[D]	$ -	$ 400
Rural or Remote Electricity Rate Protection Charge	[G]	$ 0.0003	$/kWh	[G]*[D]	$ 300	$ 300
Standard Supply Service - Administrative Charge (if applicable)	[H]	$ 0.2500	$	[H]	$ 0.25	$ 0.25
				Monthly regulatory charge for customer	$ 3,500	$ 3,900

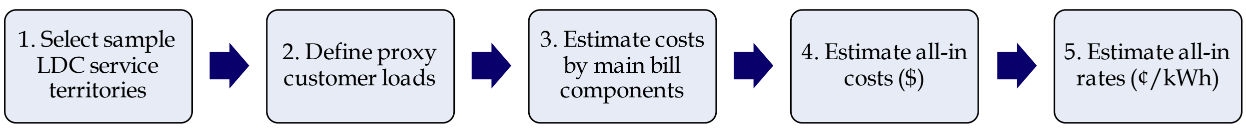
Sources: Toronto Hydro and Alectra's Decision and Rate Order for 2018

[8] Based on line items in LDC rate sheets.

2.2 Estimation of industrial electricity costs

LEI's approach to estimating 2018 industrial electricity cost examples in Ontario is summarized in Figure 13 and further outlined in the sub-sections below. At a high level, the first step was to select a sample of LDC service territories, which would determine what delivery rates, charges, and service classification levels would be used in the electricity cost estimation. Second, three proxy customers were defined, with the point of showing the impact demand levels and load shifting can have on end bills (particularly with respect to Class A customers). Once the LDC territories and proxy load profiles were selected, the next step was to build up the average costs of the main components that go into industrial electricity bills, the sum of which provides the estimated all-in electricity costs. Finally, once the end bill was estimated, it was converted to rates (dividing the all-in bill by consumption to get a ¢/kWh number), which is presented alongside the implied system average all-in electricity rates in Ontario for Class A and Class B customers for additional colour.

Figure 13. Approach to estimating industrial electricity costs



2.2.1 Sample LDC service territories

Delivery rates and charges vary for industrial customers based on which one of Ontario's over 60 LDCs serves them. For the purposes of a rates comparison, LEI chose a sample of three LDCs to serve as a proxy, based on the size of the large load they serve – Toronto Hydro, Alectra (Enersource rate zone), and Hydro Ottawa, which together accounted for over 40% of Ontario's large GS and Large Use load.[9] 2018 rates for these three LDCs are presented in the figures below. Figure 14 shows the rates for the largest GS classification for the LDCs (which ranges from between 500 kW – 4,999 kW to between 1,500 kW – 4,999 kW), while Figure 15 shows rates for Large Use classified customers (having peak loads of 5,000 kW or higher). As can be seen in the figures, delivery rates differ between LDC zones, while regulatory rates generally do not. For the purposes of industrial bill estimation, a weighted average of these rates was created based on consumption levels for the LDC larger use customers, based on data from the OEB's 2016 Yearbook.[10] Assigned weights for each LDC are shown under their names.

[9] Based on information contained in the OEB's 2016 Yearbook of Electricity Distributors.

[10] 2016 Yearbook used as that was the last year with Enersource's information listed separately (2017 Yearbook provides information on Alectra).

Figure 14. Rates for large general service customer[11]

Component	Unit	LDC			
		Alectra - Enersource (19%)	Toronto Hydro* (65%)	Hydro Ottawa (16%)	Weighted average
Delivery	**Unit**	**Amount**			
Service Charge	$	$1,764.42	$946.52	$4,193.93	$1,632.54
Distribution Volumetric Rate	$/kW	$2.3994	$6.68701	$4.1834	$5.4590
Retail Transmission Rate - Network Service Rate	$/kW	$2.6436	$2.4821	$2.8472	$2.5725
Retail Transmission Rate - Connection Service Rate	$/kW	$2.4803	$2.0494	$2.0414	$2.1305
Low Voltage Service Rate	$/kW	$0.0784		$0.02564	$0.0192
Various rate riders charged in $ terms	$	$71.83	$24.37		$29.47
Various rate riders charged in $/kW terms	$/kW	($0.1027)	($1.4560)	($0.56)	($1.0513)
Rate rider for disposition of CBR account **(only applicable to Class B)**	$/kW	($0.01999)	$0.0322		$0.01694
Rate rider charged in $/kWh terms	$/kWh	($0.0005)	($0.0011)	($0.0007)	($0.0009)
Regulatory	**Unit**	**Amount**			
Wholesale Market Service Rate	$/kWh	$0.0032	$0.0032	$0.0032	$0.0032
Capacity Based Recovery **(only applicable to Class B)**	$/kWh	$0.0004	$0.0004	$0.0004	$0.0004
Rural or Remote Electricity Rate Protection Charge	$/kWh	$0.0003	$0.0003	$0.0003	$0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	$0.25	$0.25	$0.25	$0.25

* Toronto Hydro's distribution volumetric rate and volumetric rate riders are billed on a $/kVA basis, which LEI converted to $/kW for consistency using a power factor of 0.92 (based on assumption in Toronto Hydro's bill impacts rate model from its 2019 rate application [EB-2018-0071])

Note: blacked out cells indicate line item does not exist in LDC's rates

Figure 15. Rates for large use customer (5000+ kW)

Component	Unit	LDC			
		Alectra - Enersource (19%)	Toronto Hydro* (65%)	Hydro Ottawa (16%)	Weighted average
Delivery	**Unit**	**Amount**			
Service Charge	$	$13,911.73	$4,178.03	$15,231.32	$7,841.61
Distribution Volumetric Rate	$/kW	$2.9782	$7.17	$3.971	$5.8493
Retail Transmission Rate - Network Service Rate	$/kW	$2.8211	$2.8295	$3.1563	$2.8812
Retail Transmission Rate - Connection Service Rate	$/kW	$2.6491	$2.2769	$2.2989	$2.3516
Low Voltage Service Rate	$/kW	$0.0838		$0.02887	$0.0207
Various rate riders charged in $ terms	$	$703.18	$111.02		$206.11
Various rate riders charged in $/kW terms	$/kW	($0.2234)	($1.3301)	($0.66)	($1.0098)
Rate rider for disposition of CBR account **(only applicable to Class B)**	$/kW		$0.0035		$0.00225
Rate rider charged in $/kWh terms	$/kWh		($0.00112)	($0.0007)	($0.0008)
Regulatory	**Unit**	**Amount**			
Wholesale Market Service Rate	$/kWh	$0.0032	$0.0032	$0.0032	$0.0032
Capacity Based Recovery **(only applicable to Class B)**	$/kWh	$0.0004	$0.0004	$0.0004	$0.0004
Rural or Remote Electricity Rate Protection Charge	$/kWh	$0.0003	$0.0003	$0.0003	$0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	$0.25	$0.25	$0.25	$0.25

Sources: LDC Decision and Rate Orders for 2018

2.2.2 Proxy customer load profiles

Industrial customer load profiles impact all aspects of their end bills. At a high level:

- **Peak demands** (in kW) and peak demand patterns impact electricity costs by determining whether they can qualify for Class A GA, while their coincident peak demands impact

[11] Alectra rates shown are for the 500-4,999 kW service classification, for the calendar year 2018; Toronto Hydro rates are for the 1,000-4,999 kW service classification, for calendar year 2018; Hydro Ottawa rates are for the 1,500-4,999 kW service classification, for calendar year 2018.

their GA costs if they choose to participate in the Class A GA. Peak demands impact delivery charges by determining which LDC service classification level the industrial customer falls under, which impacts delivery component amounts and line items. Within service classification levels, peak demands also impact delivery costs related to distribution and transmission charges, as well as certain rate riders; and

- **Consumption** (in kWh) impacts electricity costs through wholesale charges, while Class B customers are impacted on the GA side because they are charged volumetrically. Consumption also impacts certain delivery rate riders, as well as most regulatory charges.

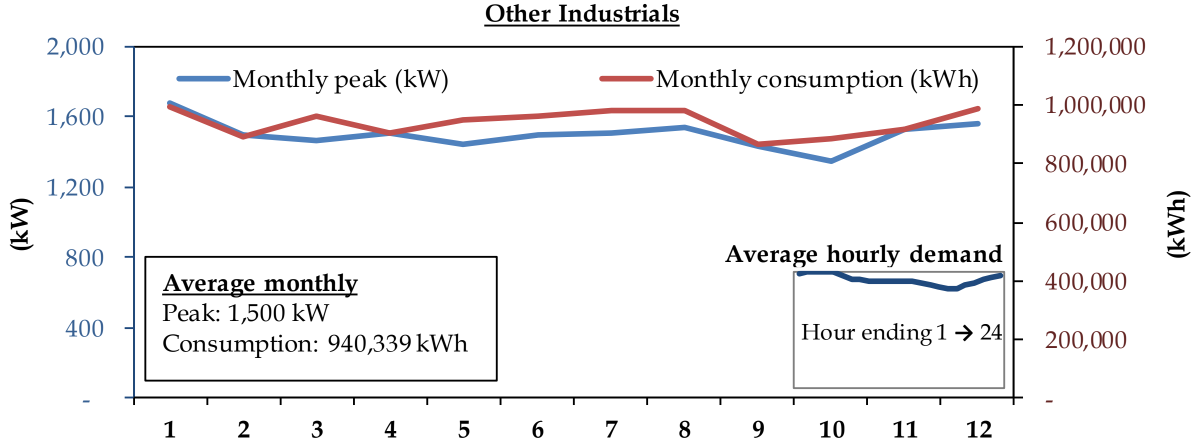
To capture differing experiences across load sizes and patterns, three proxy customer load profiles were created based on data provided by AMPCO. Proxy customer loads were selected to show the impact differing load levels and patterns have on end bills, and are based on load data from three sectors: Motor Vehicle Manufacturing, iron and steel mills and ferro-alloy manufacturing ("Metals Manufacturing"), and "Other Industrials" sectors.[12] The purpose of selecting these sectors from the wider pool of industrial sectors was purely to show a diversity of load profiles. Although each industrial customer will have its own unique peak demands, consumption patterns, and corresponding PDFs, the data provided by AMPCO is large enough to serve as a reliable representative sample. In total, the sum of 2018 consumption for these three sectors was 10 TWh, compared to a total Ontario industrial demand of around 35 TWh, meaning the data captures a large amount of Ontario's industrial load.

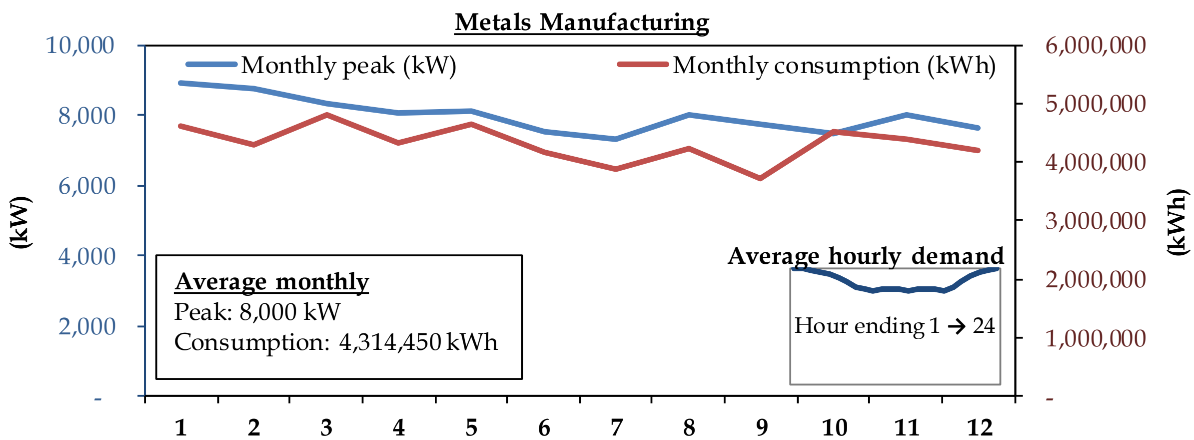
As AMPCO's load data is sector aggregated, LEI then scaled it down to reflect various load sizes. Other Industrials was scaled down to represent a single customer with an average monthly peak demand of 1,500 kW. Metals Manufacturing and Motor Vehicle Manufacturing were both scaled down to reflect a single customer with an average monthly peak demand of 8,000 kW, so total bills between the two could be compared to show the impact peak reduction has on the GA costs of end electricity bills.

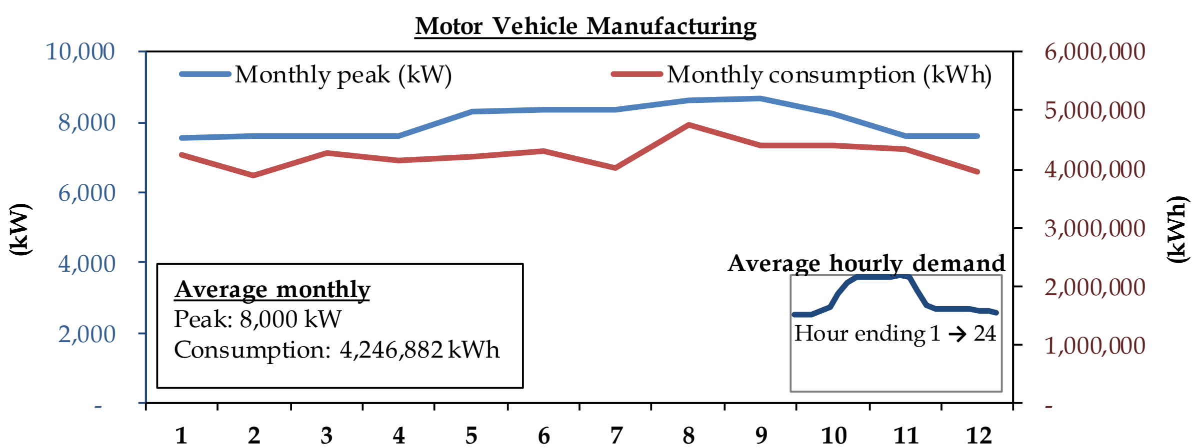
Based on this data, the proxy customer monthly peak demands and consumption used to estimate monthly bills is presented in Figure 16, along with the average monthly peak and consumption data for full-year 2018.

[12] Definitions of these groups are: (i) Motor Vehicle Manufacturing: *This industry group comprises establishments primarily engaged in manufacturing motor vehicles. Establishments that manufacture chassis and then assemble complete motor vehicles (including truck cab and chassis assemblies) and those that only manufacture motor vehicle chassis are both classified in this industry group*. [Source: Government of Canada's Canadian Industry Statistics definition] (ii) Iron and steel mills and ferro-alloy manufacturing: *This industry group comprises establishments primarily engaged in smelting iron ore and steel scrap to produce pig iron in molten or solid form; converting pig iron into steel by the removal, through combustion in furnaces, of the carbon in the iron. These establishments may cast ingots only, or also produce iron and steel basic shapes, such as plates, sheets, strips, rods and bars, and other fabricated products. Electric arc furnace mini-mills are included. Establishments primarily engaged in producing ferro-alloys are also included.* [Source: Government of Canada's Canadian Industry Statistics definition] (iii) Other Industrial sectors was an aggregated group of industrials **excluding**: iron and steel mills and ferro-alloy manufacturing; metal ore mining; motor vehicle manufacturing; petroleum and coal products manufacturing; and pulp, paper and paperboard mills.

Figure 16. Proxy customer monthly peak and consumption data for 2018







Note: 'Average hourly demand' is meant to provide a visualization of average demand for each hour in 2018. Data is shown in percentage terms (dividing each average hour's demand by the highest average hourly demand), with the y-axis ranging from 50% to 100% (and x-axis ranging from hour ending 1 to 24)

To estimate the proxy customer Class A GA costs for the 2018 period, Figure 17 presents the total coincident peak demands for the proxy customers over the May 2017 to April 2018 period, along with the system peak demands. Corresponding PDFs for each proxy customer are presented at the bottom of Figure 17.

Figure 17. Proxy customer assumed peak demand factors for 2018

Date and time	Demand (kW)			
	Other Industrials	Metals Manufacturing	Motor Vehicle Manufacturing	System peak
Total (MW)	5,519	16,297	27,338	107,344,757
Peak demand factors:	0.00514%	0.01518%	0.02547%	

Note: Proxy customers are assumed to have the same PDFs for the January to June 2018 adjustment period

2.2.2.1 Electricity component

The main determinant of the electricity component of a customer's bill relates to consumption levels (kWh) and peak demands (which impacts ICI eligibility and the GA component of the bill under the Class A structure).

The wholesale component of the bill is calculated volumetrically whether a customer is Class A or Class B, based on consumption and a $/kWh charge meant to cover the HOEP.[13] The GA component of a customer's bill however does vary between customer classes, and depending on customer PDFs the GA charges for a Class A customer can vary by a wide margin compared to the same customer if it were under Class B.[14]

Using each of the three proxy customers, Figure 18 shows for 2018 the estimated average monthly electricity costs depending on whether the customers were Class A or Class B, as well as their estimated wholesale charges (which are the same under Class A and Class B structures).[15] To better show the impact of successful load shifting, also presented are the average monthly charges using the same consumption assumption but the system average Class A GA rate.

For customers that have greater control of their consumption patterns, the Class A structure offers large saving opportunities compared to Class B. In these examples, Metals Manufacturing and Motor Vehicle Manufacturing proxy customers both have similar consumption levels, and both pay less as Class A customers. However, due to the Metals Manufacturing customer's greater

[13] LEI used the IESO's monthly weighted average HOEP for the January to December 2018 period.

[14] For example, a customer with successful load shifting would pay GA rates that are noticeably lower under Class A versus Class B. That customer would also pay noticeably lower Class A rates than a different customer facing a flat load, for example one running multiple shift operations.

[15] Using the load profile data covered in Section 2.2.2; Class B charges were estimated by multiplying the proxy customer monthly consumption by the monthly *1st estimate* Class B GA rates; Class A charges were estimated by multiplying the PDFs of the different proxy customers by the actual monthly GA costs for 2018; and wholesale charges were estimated by multiplying the monthly consumption and monthly weighted average HOEP.

peak reduction (lower PDF), their average monthly bills under Class A would be around $96,000 less per month compared to the Motor Vehicle Manufacturing customer.

Figure 18. Average monthly electricity costs for proxy customers

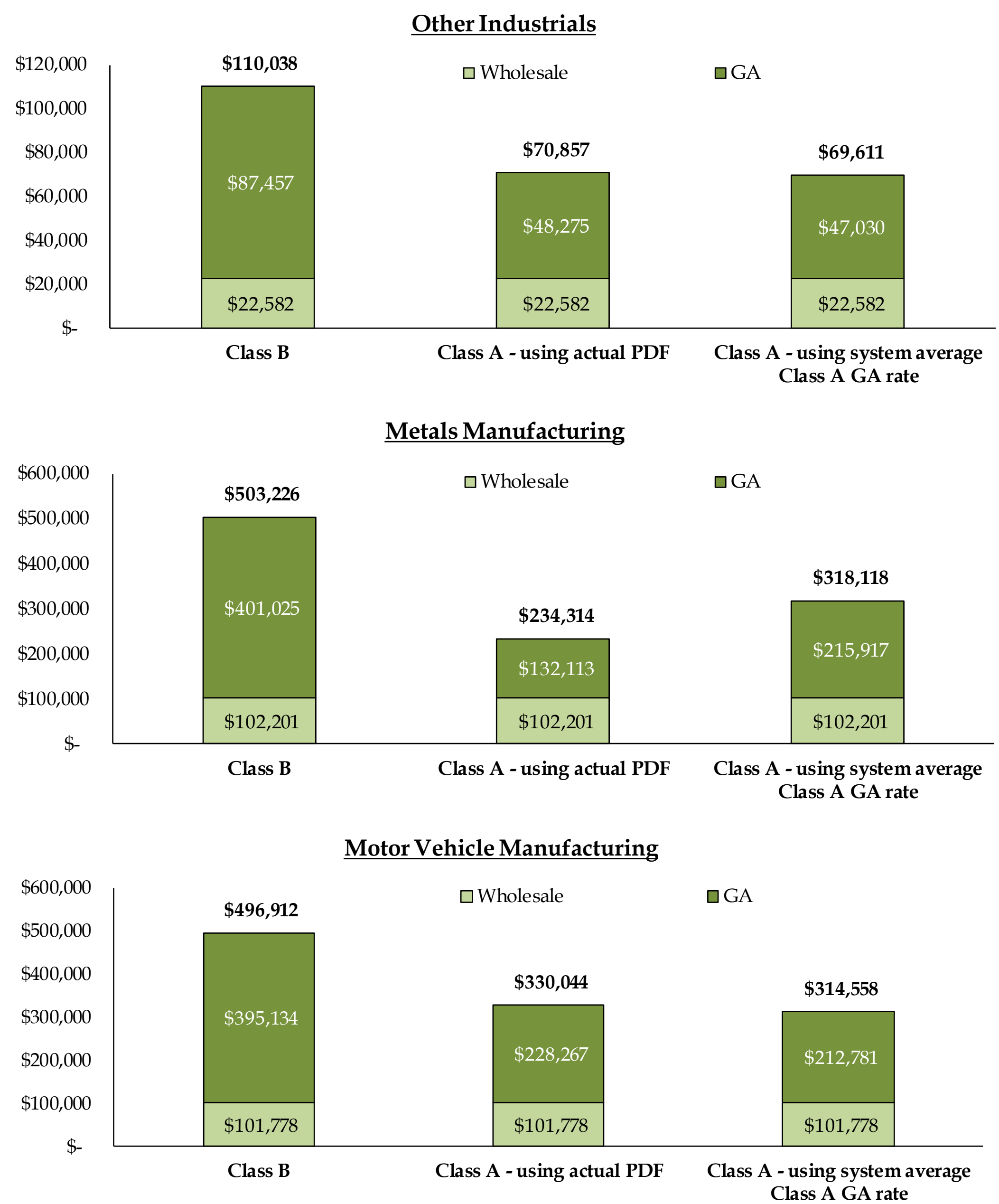
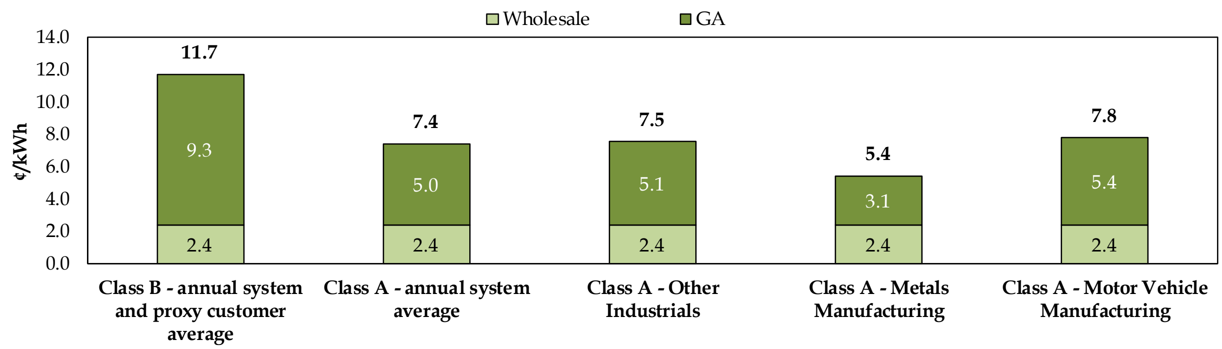


Figure 19 presents these 2018 average commodity costs in rate terms (¢/kWh). For Class B customers, the average 2018 commodity component cost was around 11.7¢/kWh, and the three proxy customers would have also paid 11.7¢/kWh under a Class B structure. Class A average costs offered a discount to this, at around 7.4¢/kWh in 2018. For the three proxy customers, the

Other Industrials customer would have paid very close to this (7.5¢/kWh), the Metals Manufacturing customer would have paid less (5.4¢/kWh) due to reduced demand at system peaks, and the Motor Vehicle Manufacturing customer would have paid slightly more (7.8¢/kWh).

Figure 19. 2018 average commodity rates for system and proxy customers (¢/kWh)

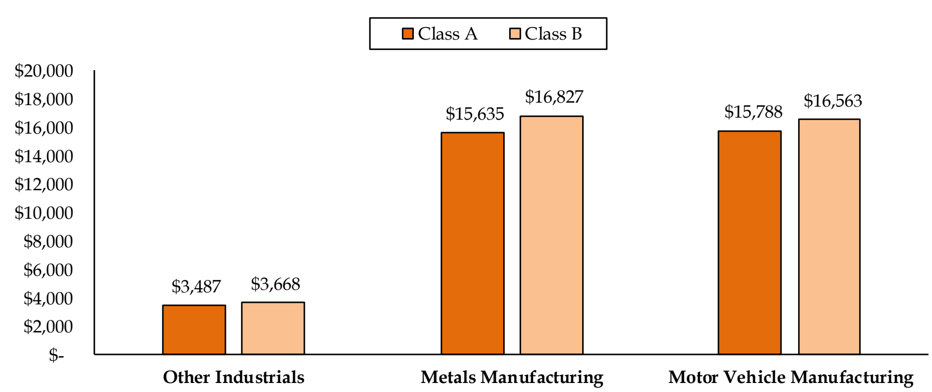


Note: 1st estimate Class B GA used
Source: System average HOEP, Class B, and Class A rates based on IESO data

2.2.2.2 Regulatory component

Regulatory costs are the same across LDC service territories, and are driven by monthly consumption (kWh). One charge, the Capacity Based Recovery, is only applicable volumetrically to Class B customers, causing a Class A customer's regulatory charges to be marginally lower than the same customer under a Class B structure.[16] Figure 20 shows the 2018 average monthly regulatory charges for the three proxy customers under a Class A and B structure, estimated by multiplying the regulatory charges shown in Figure 14 by each customer's monthly consumption. Regulatory charges make up a relatively small component of the overall customer bill.

Figure 20. Average monthly regulatory costs for proxy customers under Class A and Class B

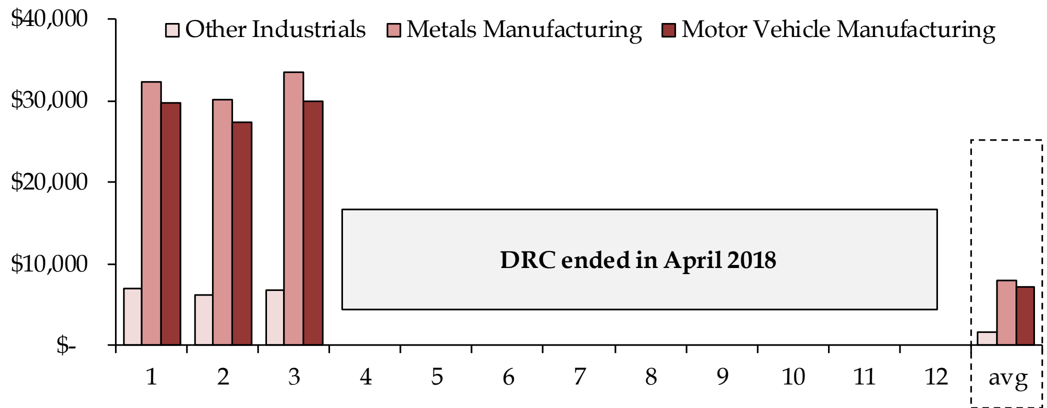


[16] Capacity Based Recovery ("CBR") applied to Class A customers based on total system CBR amount and customer's corresponding PDFs, and are included in the regulatory charges shown in Figure 20.

2.2.2.3 Note on the Debt Retirement Charge

The Debt Retirement Charge ("DRC") was a separate line item on customer electricity bills that was removed as a customer charge beginning in April 2018. However, as this part of the study is meant to show the cost of electricity over the 2018 period, the DRC of $0.007/kWh was still applied for the first three months of 2018. Figure 21 shows the monthly impact of the DRC for the three proxy customers, with the volumetric DRC of $0.007/kWh being charged based on monthly consumption from January to March only. The average impact of the DRC is also shown in Figure 21.

Figure 21. Monthly debt retirement costs for proxy customers in 2018



2.2.2.4 Delivery component

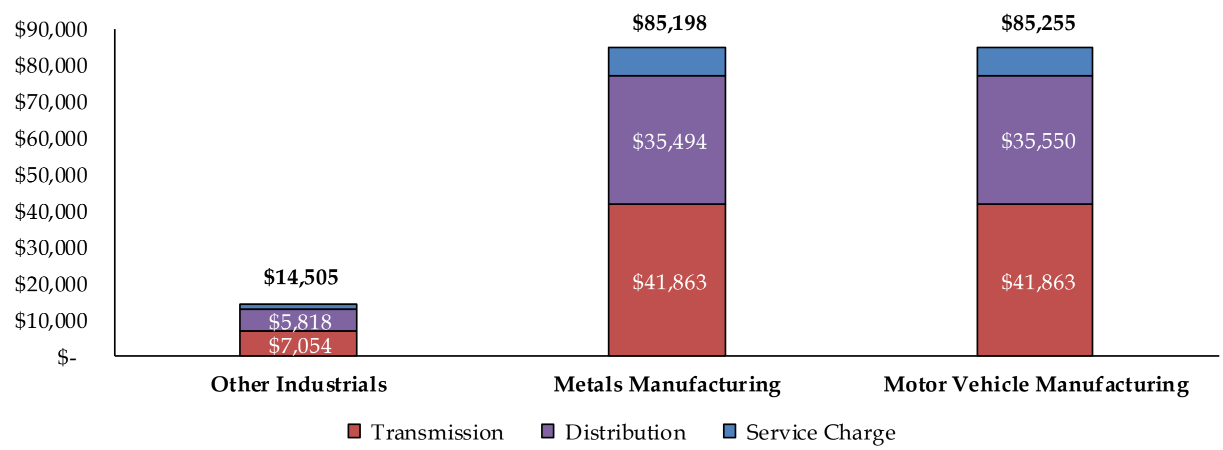
Average monthly delivery costs for the three proxy customers in 2018 are presented in Figure 22.[17] The largest determinant of the delivery component for an industrial customer's bill relates to peak demand. First, peak demand determines what tariffs and rate charges apply to the customer by grouping them into service classifications. Aside from assigning service classification levels, peak demand also drives the delivery components of an industrial customer's bill as the majority of delivery line items are charged on a $/kW basis, including distribution and transmission demand rates. Other monthly billing determinants include volumetric consumption charges (typically only affecting certain rate riders) and flat dollar charges (the largest of which is the service charge). As customer load levels increase, the impact of fixed service charges becomes more and more marginal, and the impact of capacity-based distribution and transmission charges becomes more important in determining the delivery

[17] Based on weighted average of the three LDC rates, with weights determined by the larger user consumption levels for the three LDCs using data from the OEB's 2016 Yearbook. Weights used were: 65% Toronto Hydro, 19% Enersource, and 16% Hydro Ottawa. An alternate approach of using weights based on number of larger use customers would not materially impact results.

component of bills. However, an industrial customer's status as Class A or Class B generally has a negligible impact on the delivery component of their bills.[18]

As covered in the next sub-section, delivery costs for the proxy customer loads represented a fraction of ***all-in*** bills – ranging from 11% on the low end for the Class B Other Industrial customer, to 25% on the high end for the Class A Metals Manufacturing customer.[19]

Figure 22. Average monthly delivery costs by component for Class A customers



Note: Rate rider costs/credits included in the distribution component. Impact of customer classification as Class A or B is negligible for delivery component – in this example, Class B delivery costs would be around $26 lower per month for Other Industrials, and $18 lower per month for Motor Vehicle Manufacturing and Metals Manufacturing

2.2.2.5 All-in bills

Figure 23 shows the all-in average monthly bills for the three proxy customers in 2018, both pre and post-tax. Although customer bills may vary between LDCs due to different LDC-specific rates and charges for the year, the impact of these differences is greatly suppressed by the size of the GA component of customer bills, as visible in Figure 23.[20] The net effect is that the GA remained the driver for proxy customer bills, and that participation in the ICI would have benefited all three proxy customers (with the degrees of benefit depending on their ability to reduce consumption at the top five system peak periods). For example, the Metals Manufacturing customer would have seen the greatest benefit from participation in the ICI, seeing an average monthly bill reduction of around 44% under a Class A billing structure (as compared to Class B). The other proxy customers also benefited to a slightly lesser extent, with the Other Industrials

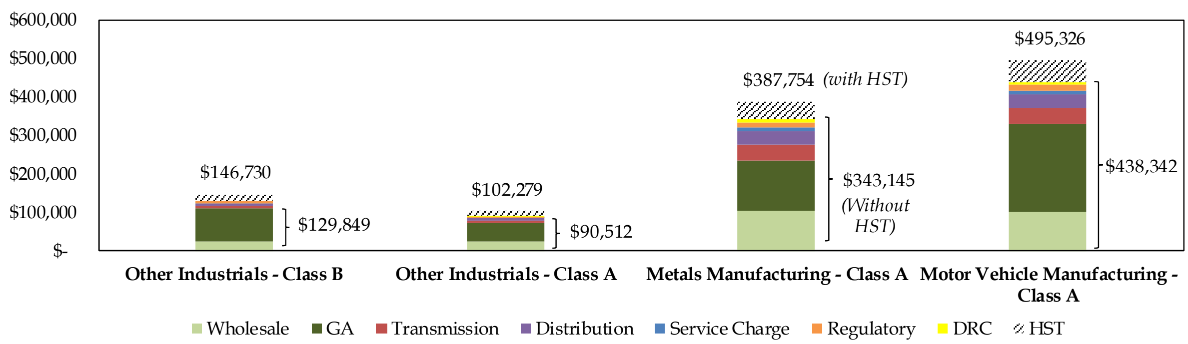
[18] When a customer's delivery charges differ under Class A or Class B, it is only through a small rider that has a negligible effect on the overall bill.

[19] For the two other proxy customers, delivery costs represented 16% of all-in costs for the Class A Other Industrials customer, and 19% for the Class A Motor Vehicle Manufacturing customer. Differences in percentage representation is due mostly to the difference in GA costs seen by the different customers.

[20] Line losses were excluded from this analysis. For reference, based on information contained in the Q1 to Q4 Ontario Energy Reports, the implied cost of line losses for LDCs covered in LEI's analysis amounted to around 0.046¢/kWh, which would have little impact on results.

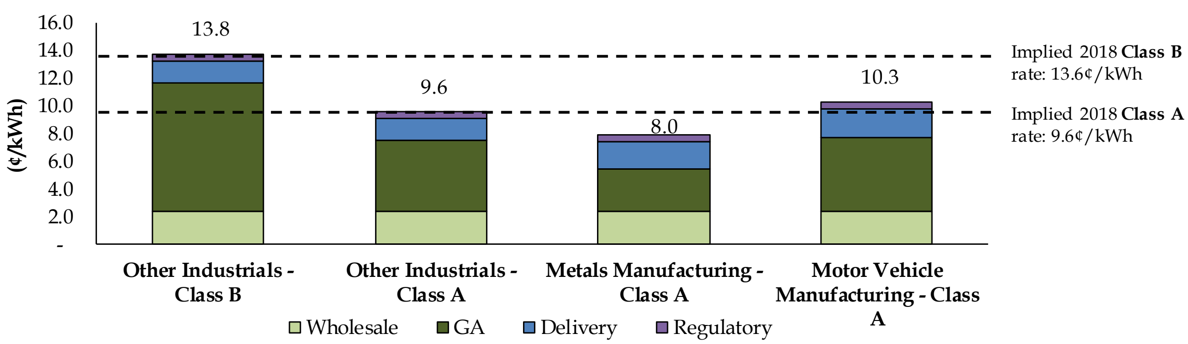
customer seeing an average 30% reduction, and the Motor Vehicle Manufacturing customer seeing a 28% reduction.

Figure 23. Average monthly all-in costs by component for proxy customers



Finally, these all-in costs (pre-tax) were divided by consumption to get implied average all-in rates on a ¢/kWh basis, as presented in Figure 24. To provide additional colour, also presented are the implied average industrial rates for distribution-connected customers based on data from the Q3 2018 Ontario Energy Report ("OER").[21]

Figure 24. Average 2018 rates for proxy customers and implied average Class A and B rates



Note: Pre-tax values presented. Delivery and regulatory charges for implied Class A and B rates are from the Q3 2018 OER, and therefore do not include the DRC. Rates for the proxy customers are the pre-tax costs presented in Figure 23 divided by average consumption; delivery includes transmission, distribution, and services; regulatory includes the prorated DRC up to April 2018.

[21] To estimate implied 2018 Class B rates, LEI took the simple average delivery and regulatory costs presented in the Q3 2018 OER, and added the weighted average 2018 HOEP and Class B GA from the IESO's December 2018 monthly market report. For Class A rates, the same approach was taken using the 2018 average Class A GA rates. OER rates are meant to represent a hypothetical customer with a monthly peak demand of 5,000 kW and consumption of 3,060,000 kWh.

2.3 Observations

To summarize:

- The main driver for electricity rates in Ontario relates to the commodity costs, and in particular the GA. Delivery and regulatory costs form smaller portions of the bill, and do not vary significantly between similarly sized industrial customers (unlike the GA, which can vary based on customer classification and load shifting capabilities);

- Ontario's large Class B customers face higher electricity rates, and the largest determinant of their bills (the GA) from a customer's perspective is charged based on a rate that does not vary within months based on time of use or hourly system demand conditions; and

- The ICI offers qualified participants the opportunity for material cost savings, and customers that have greater control of their load can reduce the GA portion of their monthly bills significantly, while also benefiting the system by reducing demand at system peaks.

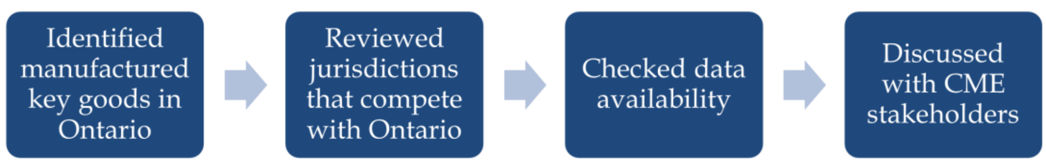
3 Assessment of electricity rates in competitor jurisdictions

This section focuses on rates and rate designs for similar proxy customers in jurisdictions that compete with Ontario. To assess the competitive electricity rate levels, LEI has identified five jurisdictions, assessed rate changes and rate designs on similarly situated customers in those jurisdictions, and modeled 2018 monthly bills across jurisdictions for the three proxy customers that were studied in Section 2.2.2. This analysis aims to provide an understanding of which rate designs result in the most competitive rates, where "competitive" is defined as rates consistent with customer cost causation and system impact.

3.1 Selection of jurisdictions

LEI identified five jurisdictions which account for locations of manufacturers of key goods currently made in Ontario, including Alabama, Illinois, Indiana, Michigan, and Germany. Analysis of the selected US states follows in the subsections below, while the discussion of Germany can be found in the Appendix (Section 7.3). The selection of the markets covered in this report follows the method in Figure 25.

Figure 25. Selection of comparators



First, LEI reviewed sales ($) of manufactured key goods in Ontario and identified the top three key goods as transportation equipment manufacturing, food manufacturing, and chemical manufacturing.[22] Then, LEI identified jurisdictions that compete with Ontario in these manufacturing sectors, including China, the United States, and Germany.[23] Based on data availability, LEI selected the US and Germany for further analysis. Within the US, Alabama, Illinois, Indiana, and Michigan were selected because of their (i) competitiveness in the aforementioned manufacturing sectors, and (ii) representativeness of key manufacturing regions in the US.[24] A comparison of key metrics is shown in Figure 26.

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[22] Statistics Canada. *Manufacturing sales by industry and province, monthly (2016 and 2017)*. Access date: February 15, 2019.

[23] Based on LEI's analysis of rankings from World Bank, European Automobile Manufacturers Association, International Trade Center, and Food and Agriculture Organization of the United Nations.

[24] Based on the data from the Center for Manufacturing Research of the National Association of Manufacturers, and discussion with CME members.

Figure 26. Key metrics comparison

Key metrics	Ontario	Alabama	Illinois	Indiana	Michigan
Real GDP growth, 2018	2.2%	2.7%	3.2%	3.2%	3.3%
Population, estimates 2018	14,193,384	4,887,871	12,741,080	6,691,878	9,995,915
Land area, square kilometers	1,074,850	131,171	143,794	92,790	146,436
Average industrial rates, Canadian cents/kWh	10.8/15.4	7.9	8.6	9.3	9.5

Notes: Ontario's population estimate is for 2017; real gross domestic product ("GDP") growth for the states in the US is the average of quarterly growth from Q1 to Q3 in 2018; exchange rate used is CAN$ 1.3 = US$ 1; taxes are included in the industrial rates. Ontario industrial rates are estimated by LEI based on information contained in the Q3 2018 OER and the IESO's December 2018 monthly market report (for distribution-connected customer, including HST).

Sources: US Department of Commerce; US Census Bureau; Ministry of Finance, Ontario; Government of Ontario; Statistics Canada; EIA 2018; LEI estimation (Ontario's rates: Class A: 10.8, Class B: 15.4).

Within each jurisdiction, LEI ranked electric utilities by industrial electric sales in 2017 and selected a large utility in each for further analysis of rate design and electric bills.

Figure 27. Representative electric utility in each jurisdiction

Jurisdiction	Representative electric utility	Industrial Electric Volume (MWh), 2017
Alabama	Alabama Power	22,686,919
Illinois	Commonwealth Edision ("ComEd")	9,469,711
Indiana	Northern Indiana Public Service Company ("NIPSCO")	27,466,955
Michigan	DTE Electric Company ("DTE")	12,020,111

Note: NIPSCO is the second largest electric utility in Indiana in terms of industrial electric volume in 2017; NIPSCO was selected because the publicly available rate design information of Duke Indiana (the largest electric utility in Indiana) is incomplete.

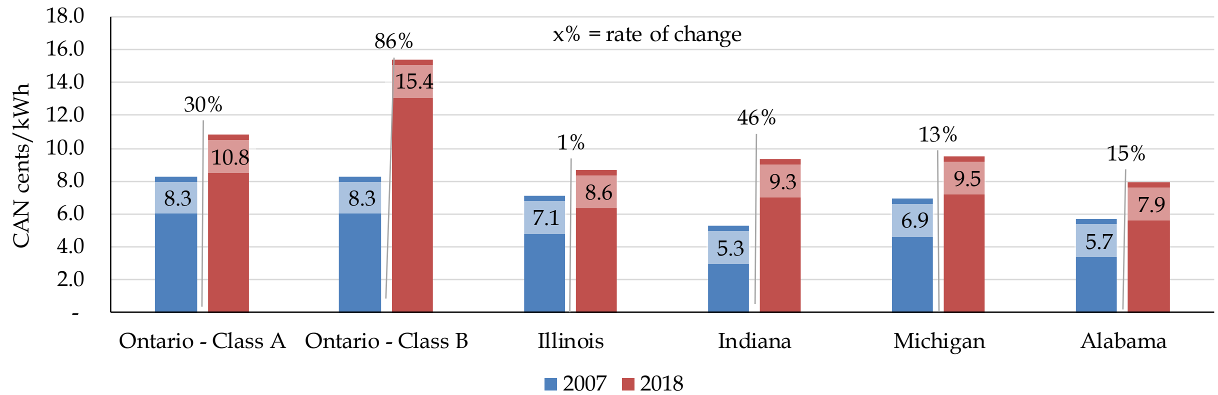
Source: EIA Form 861

Then, LEI reviewed the industrial rates in 2007 and 2018 in each jurisdiction. In 2018, Ontario's industrial rates were higher than the comparators (see Figure 28).[25] The rate for Class A was 22% higher than the average of selected state rates, while for Class B, the rate was 75% higher than the average. Moreover, the change in Ontario's industrial rates from 2007 to 2018 was more significant compared with the selected states in the US. Electricity rates for industrial customers increased more rapidly in Ontario (30% for Class A and 86% for Class B) than Illinois, Michigan, and Alabama over the past 10 years. Similar to Ontario, Indiana also saw a big jump in industrial rates. According to the Indiana Utility Regulatory Commission, historically the dependence on coal as a primary fuel source contributed to Indiana's relatively low-cost electricity, however, "investment costs to address environmental mandates, the general trending of increased coal

[25] Note average rates in Figure 28 are inclusive of taxes. EIA data on industrial rates includes taxes; for a more direct comparison with this data, HST (13%) was added to average Ontario rates. Also note that rates shown in Figure 28 are not the rates used to estimate proxy customer bills later in the paper. Figure 28 presents *average* rates, while proxy customer bill estimates were built up based on their individual components.

prices, decreasing natural gas prices, and the replacement of aging infrastructure have reduced Indiana's relative price advantage."[26] Exchange rates impact the comparison of electricity rates; a stronger Canadian dollar would widen the disparities.

Figure 28. Electricity rates and rate of change for industrial customers, 2007 vs. 2018



Notes:
(i) exchange rate: 2007: CAN$1.074 = US$1; 2018: CAN$1.3 = US$1, source: OECD;
(ii) 2007 Ontario rates are from the OPA's "Delivered Electricity Price Comparison" [August 2008]. 2018 industrial rates are estimated by LEI based on information contained in the Q3 2018 OER and the IESO's December 2018 monthly market report (for distribution-connected customer);
(iii) **taxes included; for Ontario, GST was 5% in 2007 and HST was 13% in 2018;**
(iv) percentage change shown above is based on the change in electricity rates in its ***original currency only***, excluding the impact of exchange rate;
(v) results are in line with Hydro Quebec's 2018 "Comparison of Electricity Prices in Major North American Cities" for the cities that fall within LEI's chosen comparator jurisdictions. According to the Hydro Quebec study, medium and large power consumers faced higher rates in Toronto and Ottawa than in Chicago (Illinois) and Detroit (Michigan), on both a pre- and post-tax basis (for customers with monthly peaks ranging from 500 kW to 50,000 kW). Ontario city rates were around 20% higher than Detroit and 40% higher than Chicago (average difference across the medium and large power consumers).

Sources: EIA. *Electric Power Annual 2007/2018*; OPA; Ontario Energy Report; IESO. *December 2018 Monthly Market Report*; LEI analysis.

3.2 Rate designs across regions

Customer type definitions and rate designs vary across jurisdictions in the US. In this section, LEI summarizes the definition of customer type as well as rate design types in each selected state. In terms of an industrial customer definition, NIPSCO has a very specific definition, while DTE does not have a definition in its rate book. Both Alabama Power and ComEd have a relatively broad definition for industrial customers, grouping them with commercial customers as "commercial or industrial" or "nonresidential". LEI selected one potentially applicable rate schedule in each utility for further billing analysis consistent with the load profiles used for the Ontario analysis.

[26] Indiana Utility Regulatory Commission. *2018 Annual Report*. Page 27.

Other rate schedules could be used or may be more beneficial to certain industrial customers, depending on its load profile, usage, location, and further consultation with utilities.

As for rate design types, industrial consumers across jurisdictions often have a three-part rate, including a fixed charge ($ per customer), a capacity charge ($ per kW), and a volumetric charge ($ per kWh) together with ascending or descending blocks in some cases. The parameters of these billing determinates are as follows:

- fixed charge – $ per customer, regardless of usage levels; typically used to recover costs related to billing and metering, outside of the generation and delivery of electricity;
- capacity charge – $ per kW, based on either customer's coincident peak demand (coincidence with system peak) or noncoincident peak demand (customer's own peak); and
- volumetric charge – $ per kWh, based on volumetric energy use; could be flat, or designed in a variety of forms including ascending or descending blocks, seasonal rates, or time-varying rates.

3.2.1 Alabama: Alabama Power

Alabama Power has three customer classifications, including residential, commercial and industrial, and farm. "Commercial and industrial" is defined as "an establishment that is used for commerce, professional, religious, educational, philanthropic, fraternal, governmental, manufacturing, mining, transportation, or similar purpose, including multiple buildings used for residential purposes".[27] Alabama Power offers several rates that are specifically designed for industrial customers, including Demand Pricing Index, Time-Of-Use Pricing Index, Other Pricing Options Index, and Real-Time Pricing Index.[28] Given the representative load profiles that we examined in Ontario, LEI used the "Rate LPLM - Restricted Light and Power Service – Manufacturing" under the Demand Pricing Index for further comparison. Rate LPLM is restricted to consumers whose Standard Industrial Classification Codes are 20-39 – i.e. the manufacturing sector, including primary metal industries, industrial and commercial machinery, electronic equipment, and transportation equipment, to name a few.

Regarding rate design, Alabama Power's fixed charge includes a monthly base charge and "Natural Disaster Reserve". Its capacity charge is based on the maximum integrated 15-minute capacity during each billing period.[29] The volumetric charge consists of a charge for energy and "Energy Cost Recovery" (i.e. the fuel charge). The charge for energy has descending blocks (lower rates for energy over 250 kWh per kVA of billing capacity than the first 250 kWh) as well as seasonal rates (higher rates for months from June to September).

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[27] Alabama Power. *Rules and Regulations for Electric Service*. Page 13.

[28] Alabama Power. *Industrial Rates – Rates and Pricing*. Website. Access date: April 26, 2019. <https://www.alabamapower.com/industry/rates/rates-and-pricing.html>

[29] Alabama power. *RATE LPLM- Restricted Light and Power Service – Manufacturing*.

3.2.2 Illinois: ComEd

ComEd's retail customers are segmented into three sectors: the residential sector, the lighting sector, and the nonresidential sector. A retail customer is in the nonresidential sector if "electric service is provided to such retail customer for purposes that are predominantly other than residential purposes or lighting purposes."

As a result of the Electric Service Customer Choice and Rate Relief Law of 1997, Illinois commercial and industrial consumers have the option to buy electricity from a competitive retail electric market. Nearly all of the Illinois industrial consumers are buying power and energy service from alternative suppliers other than the incumbent utility. For instance, in 2018, 85% of the total electric usage of non-residential Illinois customers was provided by an alternative retail electric supplier.[30] According to ComEd, the retail electric suppliers sell electric power and supply service to customers pursuant to contractual arrangements that are not part of the utility's schedule of rates. Thus, LEI focused on the "Rate DSPP - Delivery Service Pricing and Performance", which is designed to allow ComEd to recover its delivery service costs through the application of a formula rate.[31]

ComEd's nonresidential delivery charges include a fixed charge (customer charge and standard metering service charge), capacity charge (primary or secondary voltage distribution facilities charge ("DFC"), and primary voltage transformer charge), and volumetric charge (Illinois electricity distribution tax charge ("IEDT")). These charges vary across delivery classes, including: (1) watt-hour delivery class; (2) small load delivery class (0 – 100 kW); (3) medium load delivery class (>100 – 400 kW); (4) large load delivery class (>400 – 1000 kW); (5) very large load delivery class (>1000 – 10,000 kW); (6) extra large load delivery class (>10,000 kW); and (7) high voltage delivery class.

The capacity charge is based on maximum kilowatts delivered ("MKD"), which is the highest 30-minute demand of electric power and energy during system peak hours.[32] For the supply component, LEI assumed the historical wholesale market energy and capacity prices in the bill calculation.[33] In addition, retail customers need to pay for volumetric-based regulatory riders including the Environmental Cost Recovery Adjustment, Renewable Portfolio Standard, Zero Emission Standard,[34] and Energy Efficiency Programs. Moreover, ComEd's franchise cost is based on the delivery service charge. State tax and municipal tax are charged based on volume ($/kWh) with descending blocks.

[30] Office of Retail Market Development, Illinois Commerce Commission. *Annual Report*. June 2018.
[31] ComEd. *Schedule for Rates for Electric Service*. Date effective: January 15, 2009.
[32] ComEd. *Schedule of Rates for Electric Service - General Terms and Conditions*. Page 142.
[33] Historical wholesale market energy prices are from Velocity Suite's database "ISO Real Time & Day Ahead LMP Pricing – Monthly Summary" (original source: PJM); capacity prices are from PJM capacity auction results.
[34] The establishment of the Zero Emission Standard was intended to support the environmental attributes of nuclear power generation. Source: IPA.

3.2.3 Indiana: NIPSCO

NIPSCO defines an industrial customer as "any customer who is engaged primarily in a process that creates or changes raw or unfinished materials into another form or product".[35] Two applicable rate schedules include "Rate 732 – Rate for Electric Service, Industrial Power Service" and "Rate 733 Rate for Electric Service, High Load Factor Industrial Power Service". When an industrial customer's load factor is higher than 70%, Rate 733 is applicable; otherwise, Rate 732 is applicable. Customers under Rate 733 "shall contract for a definite amount of electrical capacity which shall be not less than 10,000 kW" in a contract year. Customers under Rate 732 shall contract for a definite amount of capacity which shall be not less than 15,000 kW in a contract year. LEI used Rate 733 for all the load profiles in the billing analysis.

NIPSCO does not have a fixed charge (or customer charge) for industrial customers. Under Rate 733, the capacity charge is based on the billing demand which is the greatest of:[36]

- 75% of the greatest obligation to serve for the month;
- the contract demand to serve for the month less 60,000 kW;
- the maximum half-hour demand registered for the month during the peak period subtracting from the demand for each half-hour interval of the peak period of the month the Back-up, Maintenance and Temporary capacity confirmed for such half-hour interval; or
- the largest of the number of kW determined by subtracting from the demand for each half-hour interval of the off-peak period of the month the surplus capacity allotted and/or Back-up, Maintenance and Temporary capacity confirmed for such half-hour interval.

The volumetric charge includes energy charge and multiple riders, such as cost of fuel, RTO rider, environmental cost, and charges for resource adequacy, to name a few. The energy charge involves descending blocks which are based on 450 hours and 500 hours of the billing demand in the month under Rate 732; and 600 hours and 660 hours of the billing demand in the month under Rate 733.

3.2.4 Michigan: DTE

DTE's customer types include residential, commercial, and industrial, but its ratebook does not have a specific definition of each customer type. There are four rate schedules under the "industrial" category, including "D6.2 Primary Educational Institution Rate", "D8 Interruptible Supply Rate", "D10 All-electric School Building Service Rate", and "D11 Primary Supply Rate". LEI focused on D11 for billing analysis. D11 is available to industrial customers "desiring service at primary, sub-transmission, or transmission voltage who contract for a specified capacity of not less than 50 kilowatts at a single location".[37] If a D11 customer desires interruptible service for a total of not less than 50,000 kW of contracted interruptible service at a single location, "Rider 10

[35] NIPSCO. *General Rules and Regulations*. Effective date: November 6, 2016.
[36] NIPSCO. *Rate 733 Rate for Electric Service High Load Factor Industrial Power Service*.
[37] DTE Electric Company. *Rate Book for Electric Service* (D-48.01). Effective date: February 7, 2017.

– Interruptible Supply Rider" is available. The total contracted interruptible capacity is limited to 400,000 kW. If an industrial customer desires separately metered service at a primary voltage and would like to contract for interruptible capacity, D8 is applicable. Contracted interruptible capacity on this rate is limited to 300 MW. In 2017, power sales under the D11 Primary Supply Rate were about 19 times the power sales under the D8 Interruptible Supply Rate, and about 7 times the power sales under the Interruptible Supply Rider 10.[38]

Rate schedule D11 has several fixed charges, such as the subtransmission and transmission service charge, Energy Waste Reduction Surcharge, the Self-Implementation Refund, and a Low Income Energy Assistance Fund ("LIEAF") Factor.[39] Capacity charges include a demand charge and a distribution charge. They are applicable to monthly on-peak billing demand based on the single highest 30-minute integrated reading of the demand meter during the on-peak hours of the billing period.[40] The energy charge is volumetric-based; it has higher rates for on-peak kWh and lower rates for off-peak kWh.

3.2.5 Rate design observations

In summary, Ontario and selected US states have similar parameters in their rate designs, including a fixed charge, capacity charge, and volumetric charge. Figure 29 below compares the rate designs for the selected jurisdictions across these key parameters. Like Alabama, Illinois, and Michigan, Ontario has a fixed charge in its rate design. Similar to Alabama and Indiana, Ontario uses the non-coincident peak demand for the delivery component.

However, a major difference is that in the selected states, volumetric commodity charges available to industrial customers take different forms including descending blocks, seasonal rates, and/or time-varying rates, which could potentially benefit certain large industrial customers, depending on their load shapes and total consumption. In Ontario, Class A GA rates offer rate relief to selected industrial customers that have greater load control and incentivize load shifting, but Class B customers are charged a flat monthly volumetric charge and do not have access to a similar incentive structure.

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[38] DTE Electric Company. *Case No. U-18255 Present and Proposed Revenue by Rate Schedule*. <https://www.michigan.gov/documents/mpsc/U-18255_4-27-18_621594_7.pdf>

[39] The Low Income Energy Assistance Fund (LIEAF) Factor is a monthly per meter charge for all customers receiving retail distribution service from a participating Michigan electric utility. DTE Electric Company is participating, and the LIEAF Factor effective beginning with the September 2017 billing month is $0.93. Source: DTE Electric Company. *Rate Book for Electric Service*. Page 100.

[40] DTE Electric Company. *Rate Book for Electric Service* (D-48.01). Effective date: February 7, 2017.

Figure 29. Comparison of rate designs

Parameters	Ontario	Alabama	Illinois	Indiana	Michigan
Fixed charge?	Y	Y	Y	N	Y
Basis for capacity charge	Noncoincident peak demand for delivery component, top five system coincident peaks for Class A GA	Noncoincident peak demand (maximum integrated 15-min capacity)	Coincident peak demand (maximum 30-min demand during system peak)	Noncoincident peak demand (see details in Section 3.2.3)	Coincident peak demand (highest 30-min demand during system peak)
Volumetric charge	Delivery volumetric charges flat until new rates approved; Class B GA changes between months	Descending blocks, seasonal rates	Decending blocks for state tax and municipal tax charges	Decending blocks	Higher rates for on-peak kWh and lower rates for off-peak kWh

Note: "Y" means yes, "N" means no.

3.3 Cross jurisdictional bill comparison

LEI estimated a typical monthly bill for each proxy customer based on their load profiles and rate schedules in 2018 in each state (see Appendix 7.1) – the results of this estimation are shown in Figure 30. Note HST was included in the comparison of rates in Figure 28 for a more appropriate comparison with the EIA data (which also includes taxes), but HST and sales taxes were excluded across jurisdictions in this monthly bill comparison as this is a bottom-up approach. In general, all of the proxy customers, except Metals Manufacturing, would have higher monthly bills in Ontario than in other US states, though Metals Manufacturing would face a monthly bill in Ontario that is competitive with Illinois and Alabama (and the highest monthly bill in Michigan). The other two types of customers would have the lowest monthly bills in Alabama, followed by Illinois and Indiana.

Rate components were then categorized into three types, including an electricity component, delivery component, and regulatory component, as defined in Section 2.1 (see items under each component in each jurisdiction in Appendix 7.1). Figure 31 shows the dollar amounts of these components across the jurisdictions and proxy customers. We then calculated the percentage of each component in each jurisdiction's monthly bill. Regardless of load profiles, the electricity component was by far the largest, followed by the delivery component in most jurisdictions.

Across the load profiles, Michigan had the largest share devoted to the electricity component, while Illinois had the smallest. In absolute value, Ontario's bill had the largest (Class B) and third largest (Class A, lower than Michigan) electricity component for Other Industrial; the second largest for Motor Vehicle Manufacturing (lower than Michigan); and the second lowest for Metals Manufacturing (higher than Illinois). As for the share of the delivery component, in absolute value, Indiana had the largest and Michigan had the smallest across the five jurisdictions, while Ontario had the second largest. Finally, for the regulatory component, across the five jurisdictions

Alabama had the smallest while Illinois had the largest (including a PJM Services charge, Renewable Portfolio Standard charge, Zero Emission Standard charge, to name a few).

Figure 30. Typical modeled monthly bill in 2018

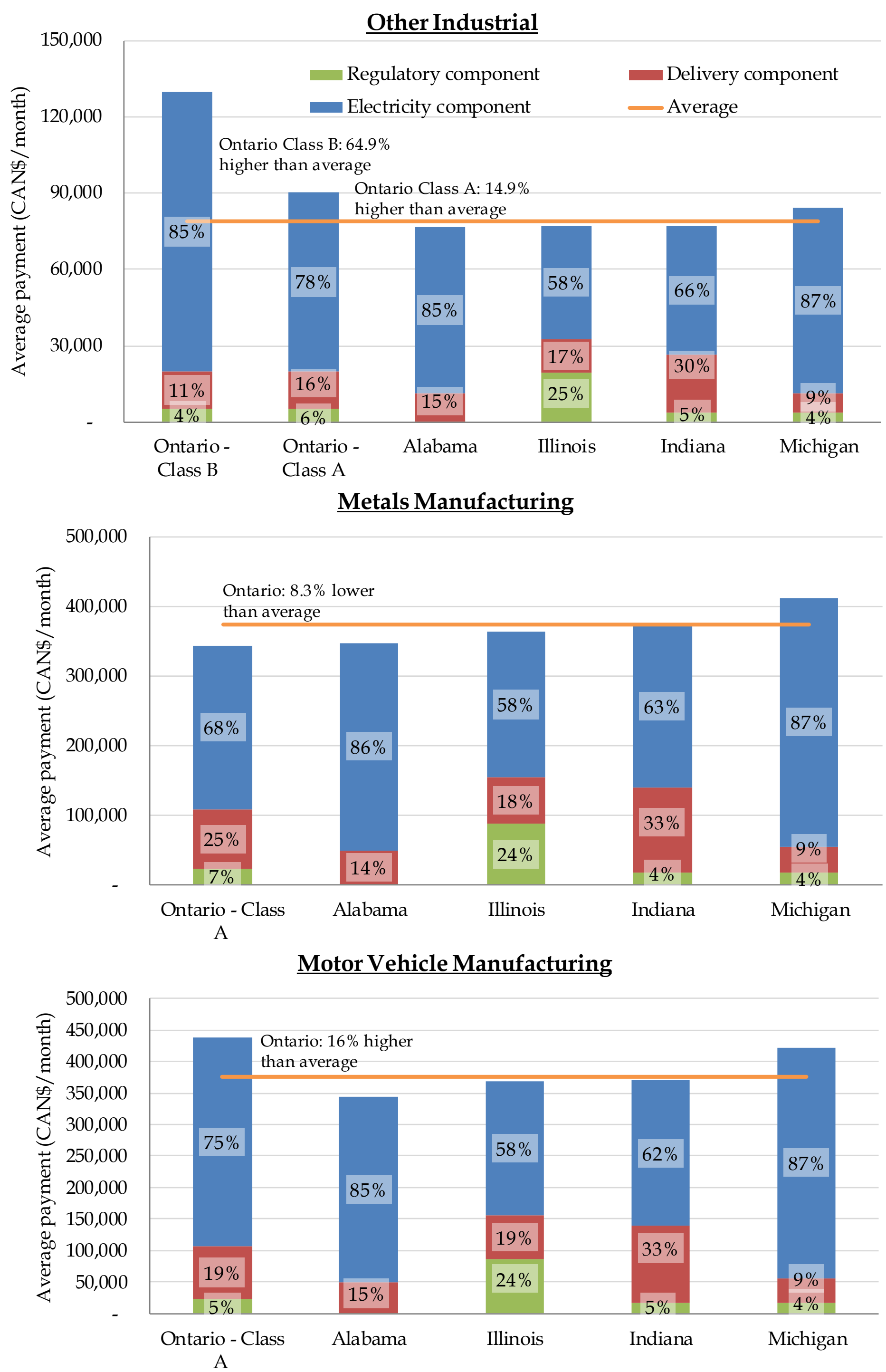
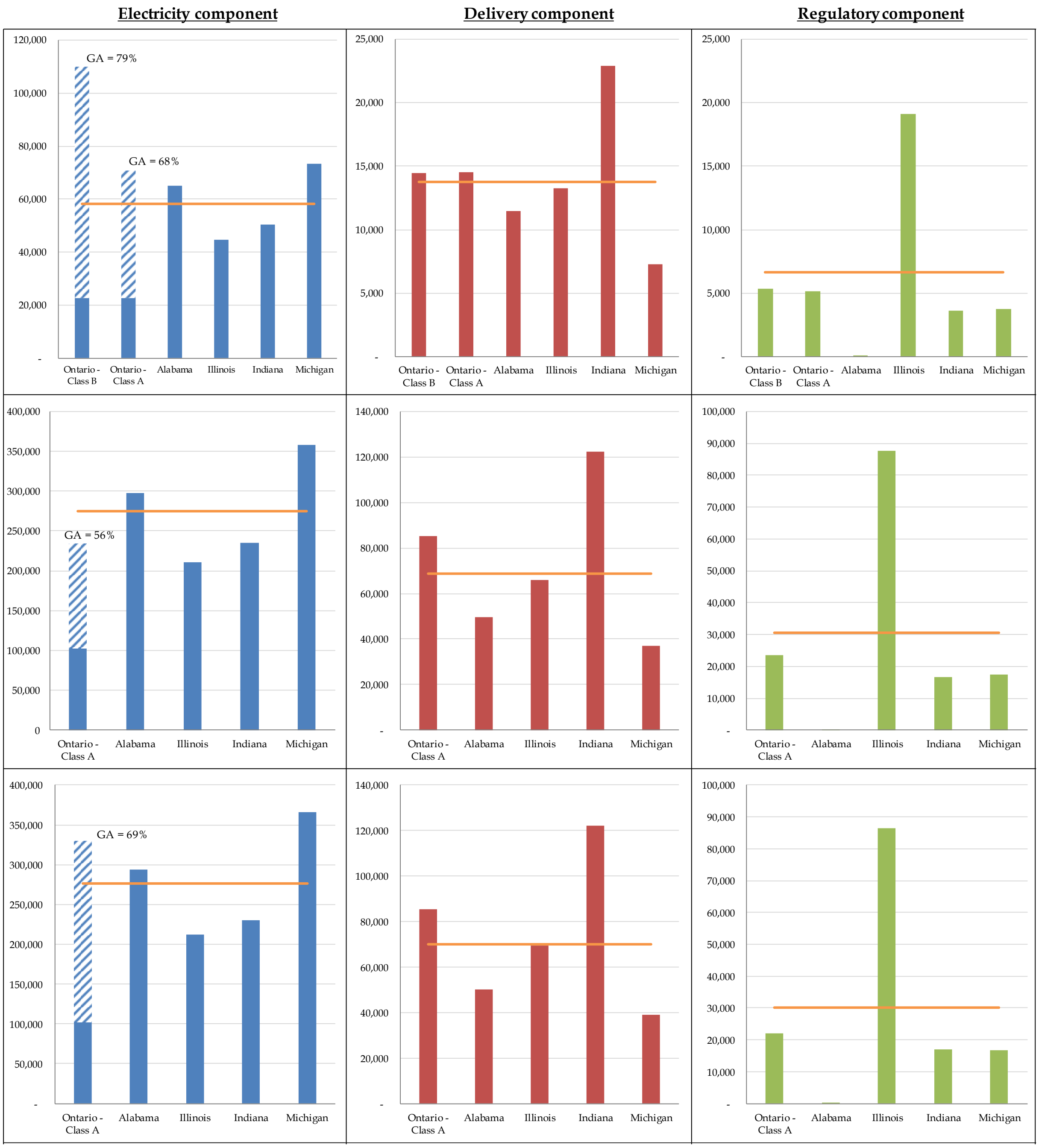


Figure 31. Typical modeled monthly bill by load profiles by components ($)



Note: the orange line shows the average level of selected US states

3.4 Observations

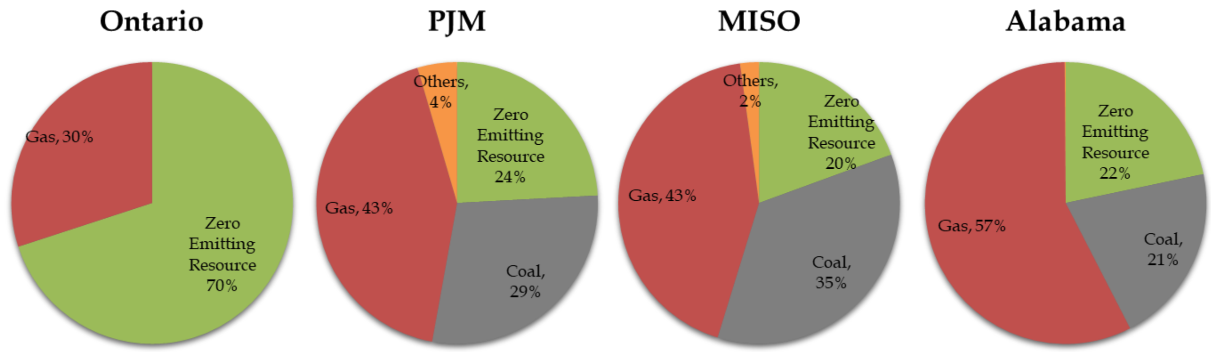
In summary, LEI has the following observations:

- Ontario's industrial rates (for both average Class B and Class A customers) were higher than comparators in 2018. Moreover, the increase of industrial rates in the past 10 years was more significant in Ontario compared with selected states in the US, especially for Class B customers (86% increase from 2007 to 2018);
- Rate designs in selected US states have descending blocks, seasonal rates, and time-varying rates, which could potentially attract certain industrial customers, depending on their load shapes and total consumptions. In contrast, Ontario's rate design for Class B industrial customers is fixed within months;
- Modeled typical monthly bills show that Other Industrial and Motor Vehicle Manufacturing customers would face higher monthly charges in Ontario than in selected US states; while for Metals Manufacturing, monthly charges in Ontario would be competitive with the lower-end bills from comparator jurisdictions;
- In Ontario, participation in the ICI offers large saving opportunities compared to the alternative as a Class B customer; better load shifting capabilities also put Class A customers on a more competitive footing in terms of all-in electricity bills compared to the US jurisdictions covered in this study, as can be seen by the lower costs for the Metals Manufacturing customer in Ontario. However, Class A customers are not homogeneous; some Class A customers face less favorable outcomes;
- For Ontario, the greatest driver of the differential is in the electricity component, especially for Class B customers. The GA accounts for over 50% of the electricity component in Ontario across load profiles;
- On average, for Class B customers in Ontario, the electricity component was 89% higher than the average of selected US states; for Class A customers of Other Industrials and Motor Vehicle Manufacturing, it was on average 21% and 20% higher, respectively. For Class A customers of Metals Manufacturing, the electricity component was 15% lower than the average of selected US states;
- On average, the modeled rates for Class B Other Industrial customers were 5.4 cents/kWh or 65% higher; modeled rates for Class A customers across load profiles were on average 0.7 cents/kWh or 8% higher. Modeled rates for selected US states were close to published average rates by the EIA (within 0.2 cents/kWh or 2% difference); modeled rates for Ontario were close to the estimation based on OER and IESO data (within 0.3 cents/kWh or 3% difference);[41]
- Ontario has a relatively higher share of zero-emitting resources compared with selected US states, as shown in Figure 32. Rates in other jurisdictions have greater exposure to fuel price volatility and carbon policy; and
- The lower level of the electricity component in other jurisdictions has prompted calls for subsidies of key resources, such as nuclear, in those jurisdictions, which could increase

[41] Taxes are included in modeled rates when they are compared with rates published by EIA, as EIA data includes taxes.

rates in comparator jurisdictions. Ontario's rates have already been impacted by contracts and regulatory arrangements to support non-emitting resources.

Figure 32. Supply fuel mix comparison, as of May 2019



Notes: ComEd in Illinois is under PJM; Indiana, and Michigan are under the Midcontinent Independent System Operator ("MISO"). Zero Emitting Resource includes renewable resources (including biomass) and nuclear. Figure is based on nameplate capacity of resources, not generation. For reference, Ontario's non-emitting resources were responsible for *generating* 94% of Ontario's transmission-connected output in 2018, according to the IESO's 2018 year-end data.

Source: Velocity Suite

4 Development of options to change rates

There are four elements to consider when assessing how to change rates:

- What are the total costs that need to be recovered?
- Who pays the costs?
- Over what time period are the costs paid?
- How will costs change in the future?

Total costs to be recovered cannot be wished away; short of abrogating contracts, which would have a chilling effect on the investment environment in Ontario both within and outside of the power sector, the costs must be recovered because they represent commitments to pay for assets that have already been built.

When determining who pays the costs, the first question is which costs belong in the electricity ratebase versus those that should be assumed by taxpayers; then for those recovered within ratebase, which electricity customers specifically should pay for those costs. Traditional rate setting processes attempt to align responsibilities for costs with cost causation – the customers with the biggest impact on the grid are those that pay a correspondingly disproportionate share of the costs. Because electricity systems are designed to meet peak needs, cost recovery has tended to be proportional to customer peak usage.

The time period over which costs are recovered has tended to be consistent with the accounting life of the underlying assets; this may differ from the economic life, meaning in theory that for longer-lived assets a longer recovery period would be possible. Furthermore, through the use of concepts like deferral accounts, rates can be smoothed over time to achieve predictability and affordability goals.

Being able to estimate how costs will change in the future is a key element of investment planning; the rapid increase in electricity costs in Ontario over the past decade is potentially of as much concern to industry, particular if it were to continue, as the relative level of rates. As the interjurisdictional comparisons show, while some Ontario customers can remain more competitive in terms of electricity costs if they participate in the ICI and can successfully load shift, even for these customers that would not remain the case if rates continue to increase at the pace they have historically. However, rates elsewhere may be entering a period of upward pressure due to challenges with environmental compliance, tight supply margins, cost overruns, and the need to replace infrastructure; if Ontario can maintain overall rates at current levels, it may regain competitiveness if rates rise more rapidly elsewhere.

Review of rates in Ontario and in competing jurisdictions leads to several conclusions. First, Class B customers generally face a greater competitive disadvantage than do Class A customers. Second, in examining the underlying components of customer bills, the source of disadvantage is less profound in the delivery charge, but is more evident in the energy charge, which is in turn driven by the GA costs. Third, rate stabilization for Class A customers may be important in addition to rate reduction.

Fourth, at a high level, LEI does not believe making significant changes in the ICI is beneficial, and any changes being considered would need to be carefully vetted with detailed studies and stakeholder interactions. The ICI's focus on reducing coincident peak behavior is economically efficient as a means of reducing future investment needs, even though the costs that it is addressing are sunk.[42] Industrial customers have made investments based on the existing program design, some of which would be stranded if changes were made. Furthermore, such investments, while avoiding GA charges today, also help the system at large avoid additional investment to serve peak load.

To attain economically efficient outcomes that benefit the province as a whole, the Government of Ontario should pursue a portfolio of measures. Each is incremental in nature, reflecting the fact that there is no magic wand which can immediately provide rate relief to one set of customers without causing challenges to another. But one of the biggest factors contributing to relatively high electricity rates in Ontario today is the tendency of previous governments to engage in grand gestures without understanding the future consequences. By pursuing a range of more targeted policies, the current Ontario government can build confidence among industrial consumers that their concerns are being heard while avoiding large scale disruption of the sector.

Below, we briefly describe four programs intended to work in tandem to address the impact of relatively high industrial rates in Ontario. Given that Class B customers face the largest competitive disadvantage with regards to rates, one is focused on Class B customers specifically. To minimize creation of new institutions while maintaining separation of policy, market, and cost recovery functions, we have suggested the use of the Ontario Electricity Finance Corporation ("OEFC") or another appropriate entity to administer the programs. We recognize that this may require additional staffing at such an entity, though this function could be largely contracted out.

4.1 Industrial Rate Relief Initiative ("IRRI") portfolio elements

4.1.1 Ending uneconomic spending

A key driver of electricity rate increases in Ontario over the past decade has been a failure to rigorously analyze the rate impact of new electricity sector policies before implementing them. For any given policy objective, Ontario has strayed from asking "what is the least cost way of achieving this objective" into assuming that a particular means (the Green Energy Act, feed in tariffs) was the best way of achieving stated ends (achieving environmental benefits). Just as a physician's first creed is to do no harm, the Ontario government should enact a policy which mandates a timely independent review of rate impact prior to promulgating new electricity sector policies. Such a review should answer both what the rate impact would be and whether there are potentially less expensive ways of achieving the same objective.

[42] One potential area for further exploration, however, is whether the ICI should allow full avoidance of GA charges if all coincident peaks are fully avoided. Because the IESO currently does not have a capacity mechanism, capacity is embedded within the GA. As capacity is effectively a payment for the existence of an asset, rather than its use, and the option to use that asset is valuable to GA customers even when they are not used, it may be appropriate to develop a minimum capacity-related charge for all customers.

By committing to a "Hydro Prudency Pledge", the Ontario government can begin to rebuild confidence among customers that ratepayer funds are not going to be wasted on grand policy gestures. The current robust supply-demand balance, coupled with the announced nuclear refurbishments, provide a sound foundation for the province over the next decade. To the extent that there are short term gaps, the government should make it clear that these will be filled on a technology, ownership, and location neutral least cost basis using IESO processes instead of directives to government-owned entities. This would include consideration of not just existing or new-build generation resources, but also demand response alternatives and imports (provided they could be delivered reliably). With respect to energy efficiency initiatives, these should be driven primarily by market-based incentives within IESO markets.

The IESO should, however, be working with counterparties to identify ways to reduce contract costs, for example by exploring an "early extension" program which would allow for voluntary opportunities to reduce current costs to the province by linking lower payments today to contract extensions for plants that are needed over the long term. Ontario could also explore an "early retirement" program for plants in which the offtakers would receive a lump sum termination payment after which they could either shut down or sell spot. While financing agreements may prevent some offtakers from taking advantage of either program, un-coerced contract renegotiations can help to gradually reduce the GA. The IESO could issue a standing request for proposals for both extension and retirement contracts, with a quarterly assessment window. Proponents would need to specifically address how their proposal would reduce the GA.

One way to further institutionalize the Hydro Prudency Pledge would be for the government to create a three-person panel consisting of senior analysts from the OEB, the IESO, and one independent, reputable private sector body. Costs of the panel would be split between the OEB and the IESO. This Rate Impact Panel would be convened at least one month prior to the launch of any policy expected to impact rates to calculate rate impact over five-, ten-, and twenty-year time horizons. The Rate Impact Panel would also have the authority to identify policy announcements with material rate impacts that have not been brought before it, and to issue reports on such policies as well. The government could further commit to asking the OEB to hold hearings on any policy expected to increase electricity rates by more than 10%.

The best way to stabilize the GA is to stop adding to it; the current government has already taken steps to avoid spending on unneeded generation, and can continue to seek mutually agreed upon economies among outstanding contracts.

4.1.2 Shifting responsibility for policy-driven contracts

A key principle of rate design is one of cost causation – that the entities which cause a cost to be incurred pay that cost. As already mentioned, this principle has tended to result in rates that allocate a greater proportion of costs to peak users of electricity. In general, rate design in Ontario tends to do this, though there is some argument with regards to whether current rate designs lead to a higher than justified compensation for avoiding peak production.[43] However, proper rate design is ineffective if the costs that are allocated using it are inefficient to begin with. Prior policymakers in Ontario abandoned a framework of large scale, least cost procurement based on a Long-Term Energy Plan in favor of a mixed procurement approach which consisted of bilateral exclusive negotiations, feed-in tariffs ("FIT"), and directives to provincially-owned entities. Justification for this switch was based on a range of arguments, none of which were directly linked to future needs of the sector itself. Examples include broadening types of owners, supporting new technologies, supporting local manufacturing, and accelerating deployment of smaller scale resources. While these objectives were packaged within an environmental plan, they did not represent a least cost way of achieving lower emissions; the centralized procurement approach could also have met that objective.

LEI's intent is not to suggest that the various policy objectives were not worthy. Rather, the question is whether it is appropriate to ask electricity ratepayers, rather than the broader population, to bear the cost. In economics jargon, the policies were targeted at positive externalities which would be enjoyed by both ratepayers and non-ratepayers alike. Because the benefits accrue to a broader population, this suggests that it would be more appropriate for the costs to also be spread more broadly. Put another way, forcing electricity consumers to bear these costs leads to inefficient pricing, which in turn leads to inefficient behavior in terms of foregone consumption. This is particularly problematic for businesses, because the foregone consumption may be as a result of them going *out* of business.

To ensure that costs that arose primarily as a result of public policy mandates are more broadly funded, LEI believes that a larger portion of the Global Adjustment should be shifted to the provincial budget. Based on an assessment of cost drivers, LEI believes that the costs of the microFIT program and the solar FIT contracts should be shifted to the provincial budget. Per unit costs of these contracts range from 22.5¢/kWh to 80.2¢/kWh; these costs well exceed the value of these contracts to the system or the cost to attain similar larger scale zero emitting resources. LEI has estimated that the total annual costs for power from these contracts is around $1.16 billion.[44] Using 2018 data, removing this cost from the GA on average would reduce GA charges by around 0.78¢/kWh for all consumers (including residential).[45]

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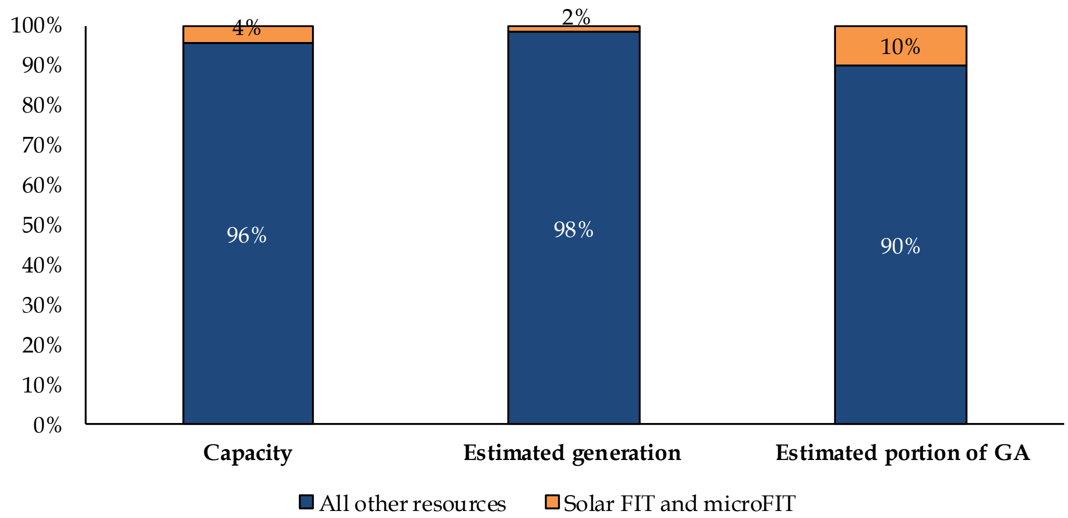
[43] See for example the Market Surveillance Panel Report from December 2018 entitled "The Industrial Conservation Initiative: Evaluating its Impact and Potential Alternative Approaches." While the paper fails to adequately acknowledge the positive role of decentralization, and the extent to which HOEP does not provide appropriate scarcity pricing signals, it raises valid concerns regarding whether the implied value of peak avoidance exceeds the value of lost load ("VoLL").

[44] LEI estimate based on all solar FIT and microFIT capacity operational by the end of Q4 2018, FIT and microFIT price schedules from the IESO, information contained in the IESO's Active Contracted Generation List, the IESO's monthly microFIT report, and capacity factor assumptions from the IESO's 2017 FIT Price Review presentation (15.6% for FIT solar, 13% for rooftop microFIT solar, and 22.8% for non-rooftop microFIT solar).

[45] GA cost for FIT and microFIT solar contracts estimated as the total contract cost of $1.16 billion net of wholesale revenues (using 2018 average HOEP and solar capacity factor assumptions from the IESO's 2017 FIT Price review presentation). This value was then divided by total consumption in 2018 (for both Class

Figure 33. Estimated Solar FIT and microFIT portions of capacity, generation, and GA costs



Notes:
(i) Total capacity estimated at 40,319 MW; total generation estimated at 154 TWh; total GA cost was $11.2 billion;
(ii) capacity includes all transmission- and distribution-connected assets, based on information from the IESO's December 2018 Reliability Outlook and Q4 2018 Progress Report on Contracted Electricity Supply (total capacity estimated at 40,319 MW, with solar FIT and microFIT capacity at 1,722 MW);
(iii) total generation estimated based on total transmission-connected generation in Ontario and total embedded generation data for 2017 from the IESO's 2018 Technical Planning Conference (which sums up to 154 TWh); solar FIT and microFIT generation estimated based on actual capacity by year-end 2018 and capacity factor assumptions from the IESO's 2017 FIT Price Review presentation; and
(iv) total GA is for calendar year 2018 from IESO data, solar FIT/microFIT GA cost was estimated by the approach covered in footnote 45 (GA estimate of $1.11 billion).

Source: LEI analysis using IESO data

4.1.3 Competitive investment linked rate buydown ("CILRB") program

While ensuring that policy-driven costs are paid for from a broader base helps improve competitiveness, given the size of the disparity between Ontario and competing jurisdiction rates, trade exposed customers likely require additional assistance. LEI does not believe it is feasible or appropriate for policy to target reducing the entire differential for all customers, nor does it necessarily believe that the entire differential should be removed for any individual customer. Instead, allocated amounts should provide for a material improvement for the most impacted customers, subject to assessment of the broader benefits to the province, commitments to desired

A and Class B customers) to get the GA charge reduction of ¢0.78/kWh. Note actual impact will vary between Class A and B customers due to how GA costs allocated between the two (reduction would be higher for Class B customers).

behavior, and clear time limitations. LEI believes a budget of $500 million per year would allow for meaningful awards to applicants.[46]

The program should be administered by an entity deemed to be free of political influence or conflicts of interest. This suggests it should not be located within the Ministry; it should also not be housed within the IESO, as doing so could undermine the perceived integrity of IESO market operations. By housing the program in an entity like the OEFC, the province can improve perceptions of objectivity provided the assigned body follows a transparent and well-structured process.

The program would be competitive and open to existing and new customers, with funding rounds occurring semi-annually. To be eligible, companies would need to demonstrate that they make greater than 25% of their sales outside of the province or are similarly impacted by imports into the province; that electricity costs make up a disproportionate share of their total costs; and that the rate buydown would provide net benefits to the Province. Because the program is intended to reinvest funds into Ontario industry, the net benefits calculation will be critical to determining the awards. Policymakers will need to be convinced that within a relatively short window (three to five years) the rate relief provided will result in a better fiscal balance than would have otherwise occurred had the program not been implemented. This improvement in future tax revenues can occur through several avenues – through the multiplier effect, as companies with better margins reinvest in plant and equipment and add employment, through greater sales as the companies become more competitive, and through retention of businesses that may have otherwise closed. However, such potential benefits would need to be carefully documented in buy-down proposals.

Companies would specify the amount of the rate buydown desired (caps can be established in terms of the total or per MWh allowable request), identify the term over which it is requested (one to three years), and enumerate benefits using published criteria, which could include jobs retention, tax payments, an assessment of the macroeconomic multiplier for the specific industry involved, and so forth. Points would be awarded according to an established formula, and companies would need to make binding commitments or risk being required to repay the rate buydown. For each funding round, the evaluation committee would select the set of projects which collectively result in the highest benefits to the province at least cost. To increase fairness, a maximum award for each participant would need to be set such that their rates would not fall *below* levels seen in competing jurisdictions.

[46] A program of this size would be approximately equivalent to the rolling three-year average of the provincial benefit from consolidating net income from Ontario Power Generation ("OPG") on provincial books. Conceptually, the program could be viewed as the province reinvesting this benefit into the Ontario economy, even though no cash actually flows from OPG.

Figure 34. Illustration of average award depending on participating load

		Customer class/group/type			
		Class A + non-RPP Class B	Non-RPP Class B	Class A	Industrial
Total consumption (TWh)		90.2	49.9	40.3	35.0
Half of consumption (TWh)	[A]	45.1	25.0	20.1	17.5
Assumed funding made available ($m)	[B]	$500	$500	$500	$500
Average award (¢/kWh)	[A]/[B*10]	1.11¢	2.00¢	2.48¢	2.86¢

Note: Class A consumption is based on IESO data for 2018; non-RPP Class B consumption is estimated by LEI as the remainder after subtracting from total 2018 consumption the total Class A consumption and the OEB's estimate for total Class B RPP consumption (59 TWh, from the OEB's 2018 RPP Supply Cost Report)

As shown in Figure 34 above, assuming the program were open to all Class A and non-RPP Class B participants, and only half were deemed worthy of a rate buydown, the average award would be 1.11¢/kWh.[47] However, by adjusting allocations between Class A and Class B participants, the average award could be reduced for Class A applicants and increased for Class B applicants, reflecting the greater relative disadvantage faced by Class B customers, and having a larger impact on a more select group of potential participants. Targeting Ontario's industrial load (around 35 TWh) and assuming half of this load qualified for the buydown, the average award would be 2.86¢/kWh.[48] Limiting further to those customers that are trade exposed and run energy-intensive operations, that either do not participate in the ICI (Class B) or participate in the ICI but face difficulty load shifting (e.g. Class A customers that run flat loads) would have a larger rate impact. The implementing body for the rate buydown program would be specifically mandated to produce an annual report assessing impact, and all award sizes and recipients would be made public.

4.1.4 Monetizing green attributes

Ontario should allow those companies who for brand reasons wish to be 100% renewable compensate those companies whose focus is more on affordable power. Based on the terms of current contracts, the IESO owns the environmental attributes related to the output of most of the power it purchases. The IESO should create a voluntary REC program which creates RECs for all

[47] The program by its nature is intended as a load retention measure. In addition, new loads could also apply, meaning funds would also provide for an additional means of load attraction. However, loads eligible for other programs, such as the Northern Industrial Electricity Rate ("NIER") Program, would not be eligible.

[48] According to data from the IESO's 2016 Ontario Planning Outlook, 2015 total industrial load was 35 TWh, while large (Class A) industrial load was 16.8 TWh (48%), implying that the remaining 18.2 TWh (52%) was Class B. LEI could not find more recent data with this level of granularity for industrial load, however given the ICI eligibility threshold was lowered from 3 MW to 0.5 MW/1 MW since then, it is most likely that a large amount of industrial load has shifted from Class B to Class A. Assuming the shift was proportional to the total growth in ICI load, Class A industrial load would be around 25.6 TWh in 2018. LEI therefore views as fair and conservative the assumption that 50% of industrial load qualifies for the rate buydown; this would cover mostly Class B industrial customers, but also Class A industrial customers that face difficulty load shifting, for example those that run flat load operations.

wind, solar, biomass, and run of river hydro facilities; these RECs would be auctioned off quarterly with the proceeds used to reduce the non-residential share of the GA.

The IESO can develop a green labeling program for companies that match all of their power consumption with RECs, and publicize the certification process. This process can be enhanced by the Government of Ontario enacting green labeling standards that prevent companies from presenting themselves as green without actually purchasing the RECs to substantiate their claim. Doing so would prevent free-riding by those attempting to burnish their green credentials. It would also create a market-based foundation for future green energy development that would not rely on ratepayer subsidies, as new projects would also be eligible to create RECs.

Even though voluntary REC programs generally produce low revenues, the effect is to shift costs to those most willing to pay them. Assuming production from qualifying sources in Ontario of approximately 27.8 TWh per year,[49] and an assumed market value of CAN$ 3 per voluntary REC, the GA offset value would be $83 million.[50] While voluntary REC markets in other jurisdictions are opaque, over the past five years LEI has observed transactions ranging from US 0.1¢/kWh to US 0.5¢/kWh. Assuming the proceeds were applied only to industrial customers (approximately 35 TWh), such customers would see a credit of around 0.24¢/kWh on their bills, or about a 2% decline on average. However, with appropriate publicity and encouragement, values for RECs could grow; even a doubling of the assumed value would be within observed bounds of the US' experience.

4.2 IRRI collective impact

The Hydro Prudency Pledge is targeted at providing industry with greater confidence regarding future rate changes. The other three program elements – shifting responsibility to the province for high cost FIT and microFIT programs, the CILRB program, and the monetization of green attributes, are targeted at reducing rates over the near term.

Under the assumptions discussed above, benefits from provincial assumption of policy-driven generation costs would equal 0.78¢ per kWh, while the benefits of monetizing green attributes would equal 0.24¢ per kWh. Combined, this equals 1.02¢ per kWh. Using the Class A "Other Industrials" customer from Section 3 as an *example*, the combined impact of the above programs could on average reduce the differential with the next highest competing jurisdiction (Michigan) from 7% higher to 4% lower.

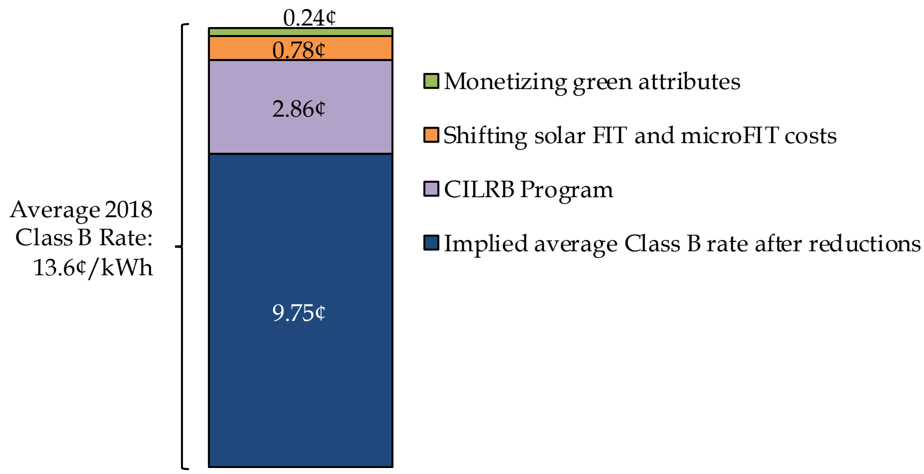
Assuming that awards in the CILRB program were focused on the subset of industrial load covered in Figure 34, the average award would be 2.86¢ per kWh; when combined with the above reductions associated with policy mandates and green attributes, the total would be 3.88¢ per kWh. The combined impact of the above programs would, for example, reduce average Class B

[49] Based on actual generation data for wind, solar, bio, unregulated hydro, and an assumption that OPG's regulated hydro facilities under 50 MW also participate (generation from these facilities estimated using their nameplate capacities and an assumed capacity factor of 58%).

[50] Excludes OPG's regulated hydroelectric generation, includes generation from all other renewable resources.

rates from 13.6¢/kWh to 9.8¢/kWh, as shown in Figure 35. Using the Class B "Other Industrials" customer from Section 3 as another example, the combined impact of all three programs could on average reduce the differential with the next highest competing jurisdiction (Michigan) from 54% higher to 11% higher (for this proxy customer). Because the implementing agency would have the ability to vary awards, some customers could receive awards to the point where the differential with the next highest competing jurisdiction would be functionally eliminated.

Figure 35. Illustrative average Class B rate and IRRI collective impact



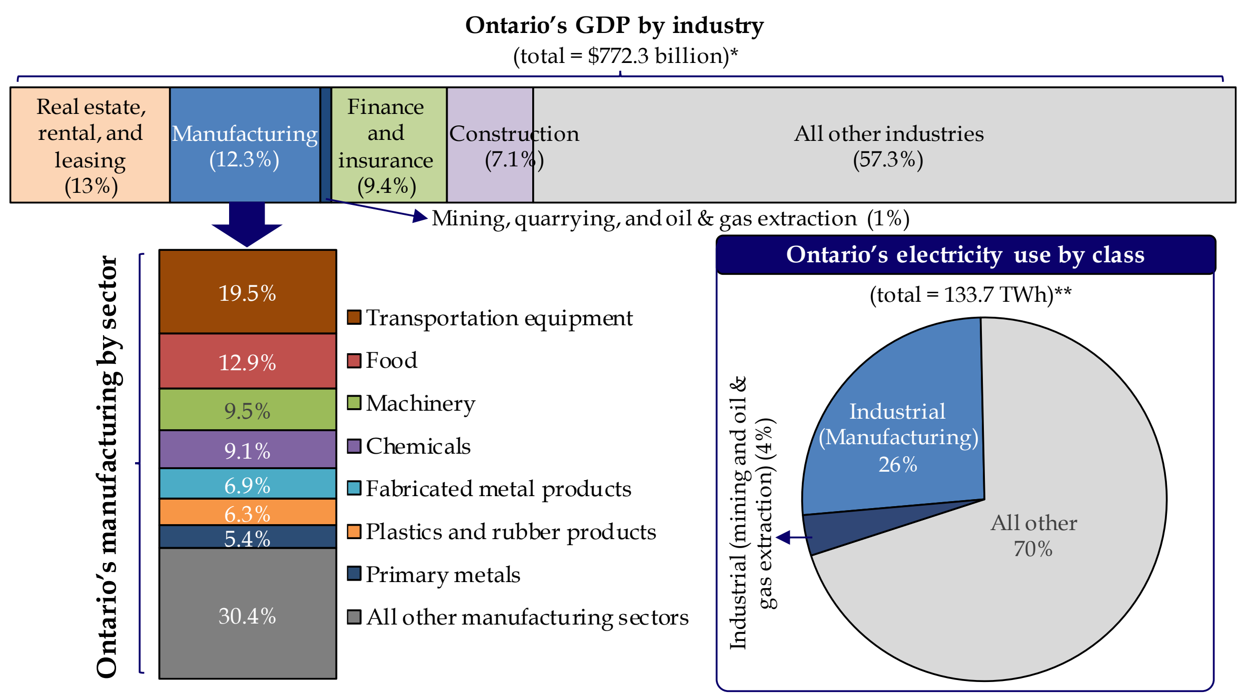
Note: As previously stated the rate buydown would be focused on Class B customers, but consideration would also be given to Class A customers that run energy-intensive operations, are trade exposed, and face higher than average Class A rates due to difficulty shifting load

5 Quantification of economic benefits from industrial rate adjustment

5.1 Overview of industrial contribution to GDP and electricity consumption

As presented in Figure 36, one of the largest individual contributors to Ontario's GDP is the manufacturing industry (second to real estate, rentals, and leasing based on 2017 data). Ontario's manufacturing industry is made up of a diverse group of sectors, including those involved in the manufacturing of transportation equipment (including motor vehicle manufacturing), food, machinery, chemicals, and fabricated metal products, among others. Ontario's diverse manufacturing base is therefore a large contributor to Ontario's overall GDP. As also visible in the bottom right of Figure 36, Ontario's industrial load, broken down into manufacturing as well as mining and oil & gas extraction, is a large consumer of total electricity – as industrial customers can run energy intensive operations in their production processes. For these customers, electricity costs can therefore form a large part of their input costs. In addition, these customers are also often trade exposed, and are therefore under a competitive disadvantage when trying to compete with goods that are manufactured in other lower-rate North American jurisdictions.

Figure 36. GDP by industry, manufacturing breakdown, and electricity use by sector (2017)



* Total GDP originally presented by Statistics Canada in 2012 dollars ($713 billion), which LEI inflated to 2017 dollar terms using Statistics Canada's Consumer Price Index data for Ontario (All Items).

** Consumption by class is based on Statistics Canada data, which may not match data from the IESO. Statistics Canada data was used to match the sources and years with the economic data also being presented. For analysis outside of this figure, LEI opted to use IESO data. Also note 'All other' customers are made up of mostly residential and commercial customers; additional details can be found on page 65 of this report.

Sources: Statistics Canada: Table 25-10-0030-01 Supply and demand of primary and secondary energy in natural units; Table 36-10-0402-01 Gross domestic product (GDP) at basic prices, by industry, provinces and territories (x 1,000,000); Table 18-10-0005-01 Consumer Price Index, annual average, not seasonally adjusted.

With this background in mind, this section explores how decreases in electricity costs for industrial consumers in Ontario could impact the provincial economy. For the purposes of quantifying potential impacts on GDP and total jobs in the province, LEI has opted to use the IMPLAN economic model. In so doing, this analysis aims to demonstrate the sensitivity of the provincial economy to changes in the price of electricity. LEI calculated the collective benefit of the rate relief provided by the IRRI; this benefit totaled approximately $849.5 million for industrial customers, as discussed in Section 4.[51] Because of the targeted nature of the programs, however, trade dependent customers would see higher savings, while other customers more insulated from international trade would see less. Regardless, all customers (including residential customers) would see some savings.

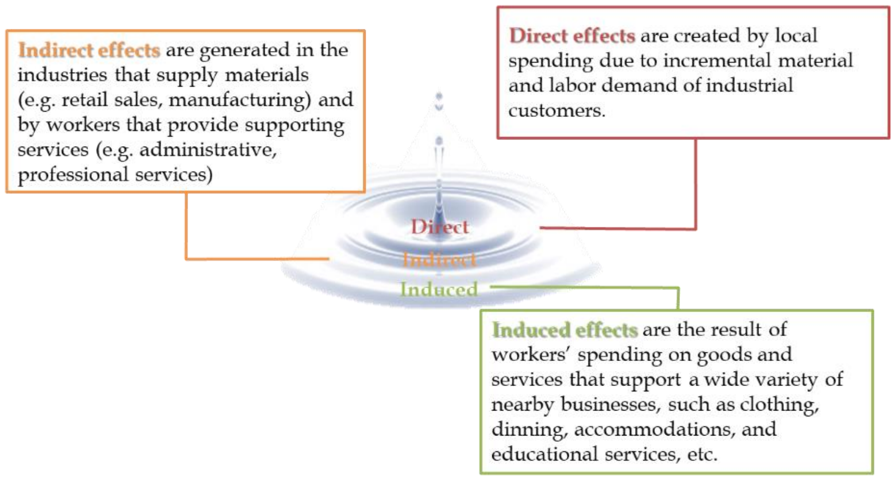
5.2 Overview of IMPLAN

IMPLAN is an input-output ("I/O") model developed under the direction of the United States Forest Service in 1976 and currently maintained by the IMPLAN Group, formerly known as the Minnesota IMPLAN Group ("MIG"), now based in Huntersville, North Carolina. Used for over 40 years, IMPLAN has been deployed by academics, governments, economic developers, corporations, nonprofits, and consultants conducting economic impact analysis.

I/O models trace the flow of goods and services through the economy based on a dollar flow I/O table known as the Social Accounting Matrix ("SAM"). Using this information, IMPLAN models the way a dollar injected into one sector is spent and re-spent in other sectors of the economy, generating waves of economic activity. These may be broken down into direct, indirect, and induced effects. **Direct effects** are created through local spending due to incremental material and labor demand of industrial customers. **Indirect and induced effects** are created as a consequence of the linkages between various industries and are also commonly referred to as the "multiplier effect" of direct effects, as illustrated in Figure 37. The model uses national industry data and county-level economic data to generate a series of multipliers, which in turn estimate the total economic implications of economic activity.

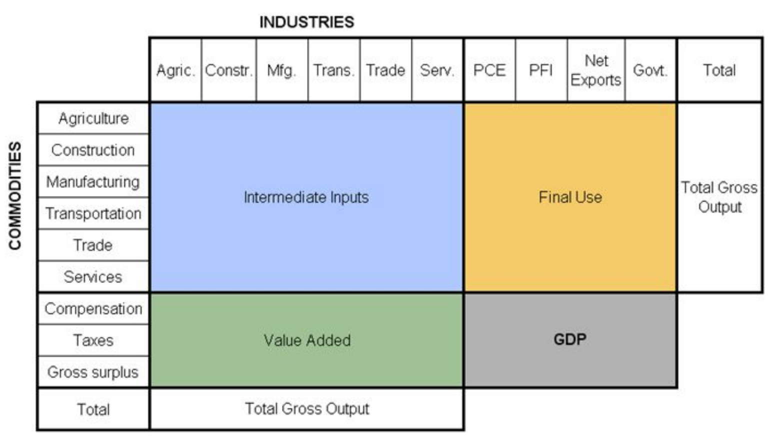
[51] Total amount of the IRRI impact covered in Section 4 was $1,688 million, based on: $1,105 million for the shifting of solar FIT/microFIT costs, $83 million for the monetization of green attributes, and $500 million for the CILRB program. The first initiative is assumed to benefit all customers (not just industrial), therefore benefit was reduced to the industrial customer proportional share of load (24%); the sum of this proportionally reduced amount, the $83 million from monetizing green attributes, and the $500 million rate buydown is $849.5 million.

Figure 37. Illustration of the "multiplier effect" from the local economic benefits



In an I/O table or SAM, such as the one presented in Figure 38, the rows represent the amount spent on a commodity or service by all other industries or institutions, including businesses and government.[52] Conversely, the columns denote the amount that an industry or institution spends on the various commodities and services as well as the wages and taxes paid. In the context of this exercise, electricity expenditure is a commodity row in the Ontario economy. The intersection of this row with each industry column represents the amount each industry spends on electricity.

Figure 38. Structure of the social accounting matrix



Source: *Bess, 2011.*

In addition to measuring the purchasing relationships between industry and household sectors, the SAM also measures the economic relationships between government, industry and household sectors, allowing IMPLAN to model transfer payments such as unemployment insurance.

[52] United States Department of Agriculture. *Guidelines for Economic Impact Analysis with IMPAN.* December 5, 2014.

5.3 Data sources

IMPLAN's data for Ontario is taken from Statistics Canada's I/O tables published in 2017 for the year 2012 and covers 103 sectors of the provincial economy. LEI has included a list of these sectors in the Appendix.

5.4 Model approach and assumptions

To specifically test the impact of reducing industrial rates, LEI first identified the sectors of the economy in which these customers are involved. As shown in Figure 39, the sectors include manufacturing and resource extraction.

Figure 39. Industry sectors subject to rate impact analysis

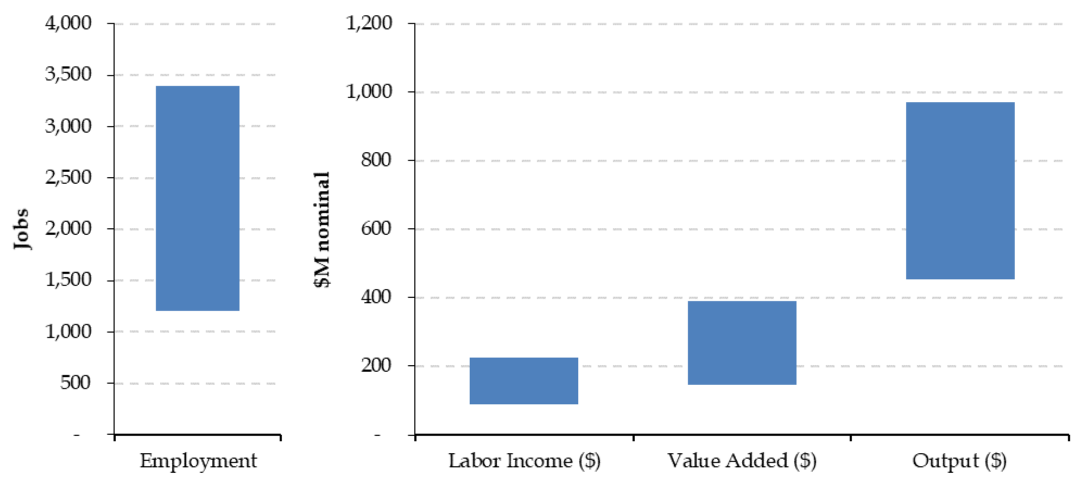
Code	Description	Code	Description
4	Support activities for agriculture and forestry	37	Pesticide, fertilizer and other agricultural chemical manufacturing
5	Oil and gas extraction	38	Pharmaceutical and medicine manufacturing
7	Metal ore mining	39	Miscellaneous chemical product manufacturing
8	Non-metallic mineral mining and quarrying	40	Plastic product manufacturing
9	Support activities for mining and oil and gas extraction	41	Rubber product manufacturing
17	Animal food manufacturing	42	Non-metallic mineral product manufacturing (except cement and concrete products)
18	Sugar and confectionary product manufacturing	43	Cement and concrete product manufacturing
19	Fruit and vegetable preserving and speciality food manufacturing	44	Primary metal manufacturing
20	Dairy product manufacturing	45	Fabricated metal product manufacturing
21	Meat product manufacturing	46	Machinery manufacturing
22	Seafood product preparation and packaging	47	Computer and peripheral equipment manufacturing
23	Miscellaneous food manufacturing	48	Electronic product manufacturing
24	Soft drink and ice manufacturing	49	Electrical equipment and component manufacturing
25	Breweries	50	Household appliance manufacturing
26	Wineries and distilleries	51	Motor vehicle manufacturing
27	Tobacco manufacturing	52	Motor vehicle body and trailer manufacturing
28	Textile and textile product mills	53	Motor vehicle parts manufacturing
29	Clothing and leather and allied product manufacturing	54	Aerospace product and parts manufacturing
30	Wood product manufacturing	55	Railroad product and parts manufacturing
31	Pulp, paper and paperboard mills	56	Ship and boat building
32	Converted paper product manufacturing	57	Other transportation equipment manufacturing
34	Petroleum and coal product manufacturing	58	Furniture and related product manufacturing
35	Basic chemical manufacturing	59	Miscellaneous manufacturing
36	Resin, synthetic rubber, and artifical and synthetic fibers and filaments manufacturing		

LEI used Ontario's economy-wide breakdown of value added or Gross Provincial Product ("GPP") to determine the percentage share attributed to each sector. LEI assumed savings from the reduction in electricity costs were received by the identified industrial sectors of the economy as incremental revenues. Each sector's incremental revenue was proportioned to the size of its value added compared to the group as a whole. Taking into account the percentage of local purchasing within each industrial sector, the model estimated the direct, indirect and induced impacts within the province. For the sake of simplicity, LEI assumed sectoral electricity consumption to be correlated with sectoral contribution to GPP.

5.5 Model results

A summary of the model results is provided in Figure 40 below, with results broken down by type of effect and category of impact. Annual results are presented as a range with direct effects making up the lower bound and the total of direct, indirect and induced benefits as the upper bound. Based on the results, the tested rate cut of $849.5 million for industrial customers would have annual job impacts ranging from 1,200 to 3,400 jobs created, a $90 million to $225 million increase in labor income, a $147 million to $389 million increase in value added, and a total output increase of $453 million to $972 million.[53]

Figure 40. Summary of indicative annual macroeconomic impacts



Impact Type	Direct effects	Indirect and induced effects	Range
Employment (Jobs)	1,200	2,200	1,200 - 3,400
Labor Income ($M)	90	135	90 - 225
Value Added ($M)	147	242	147 - 389
Output ($M)	453	519	453 - 972

Given the scope of LEI's engagement, the above analysis is purely indicative. A number of factors could influence the results, including changes in employment patterns, investment drivers, and tax rates. However, results suggest that funds invested in a carefully designed program to reduce industrial rates could earn a positive return for the Ontario economy.

[53] One caveat to these calculations is that they do not consider the source of the rate cut; to the extent that the rate cut is funded by diverting funds from other productive uses, net benefits may be smaller, or negative. While LEI believes this problem is partially addressed by proposing that rate reductions be targeted towards those entities for which the reductions would provide the greatest benefit to the provincial economy, net benefits are likely to be lower than the gross benefits presented here.

6 Concluding remarks

As covered in Section 3, Ontario rates and bills are in many cases significantly higher than competing jurisdictions, particularly in North America, though the magnitude differs depending on customer class. Ontario has the opportunity to design an Industrial Rate Relief Initiative which benefits industrial consumers while minimizing distortions to the overall economy. The initiative needs to be time-bound, targeted, commitment-linked, and to not interfere with what are otherwise economically efficient aspects of existing rate design. If the programs are appropriately administered,[54] the long run impact should be tax revenues higher than they otherwise would have been – the programs could thus be considered an investment by the province.

A summary of recommendations is as follows:

- promulgate a Hydro Prudency Pledge;
- create a Rate Impact Review Panel;
- encourage the IESO to develop early extension/early retirement standing solicitations;
- explore developing a capacity component for the ICI;
- move responsibility for solar FIT and microFIT costs to the provincial budget;
- develop a competitive investment linked rate buydown program; and
- design means to monetize green attributes.

As covered in Section 4, monetizing green attributes and shifting solar FIT and microFIT responsibility could result in an industrial rate reduction of 1.02¢ per kWh, while the CILRB program could result in an incremental rate reduction of 2.86¢ per kWh on average for qualified participants. The first two initiatives would mean a rate reduction for all industrial customers, while the rate buydown could result in some qualified customers reaching near-equivalency with rates in Ontario's higher-cost competing US jurisdictions.

The total impact of these programs on industrial customers as a whole would be a cost reduction of approximately $849.5 million. As discussed in Section 5, a cost reduction of this level for industrial customers could result in the creation of 1,200 to 3,400 jobs, a rise in labour earnings of $90 million to $225 million, value added of $147 million to $389 million, and a total output increase of $453 million to $972 million.

Whereas costs in Ontario can be expected to stabilize with careful management of the sector, those in competing US jurisdictions may begin to rise. By shifting policy driven costs to the province, and putting in place temporary but meaningful impact-based programs for industry, Ontario can improve its competitiveness without harming its overall fiscal health.

[54] LEI estimates it would take at least six months to fully design the rate buydown initiative, staff the implementing entity, and launch the first award solicitation.

7 Appendix

7.1 Rate schedules of comparators in the US

Detailed rate schedules that were used in billing calculations are listed below.

7.1.1 Alabama Power

Figure 41. Alabama Power's rate schedule

Electricity component	Unit ($CAN)	Rates
Charge for energy		
for the first 250 kWh, Oct. - May	$/kWh	0.05008
for all over 250 kWh, Oct. - May	$/kWh	0.04182
for the first 250 kWh, June - Sept.	$/kWh	0.05807
for all over 250 kWh, June - Sept.	$/kWh	0.04182
Energy Cost Recovery (ECR)		
rates vary across months	$/kWh	0.02413 - 0.03195
Delivery component	**Unit**	**Rates**
Charge for capacity		
Oct. - May; primary	$/kVa	4.88
June - Sept.; primary	$/kVa	6.18
Base charge		
Base charge	$/month	2600
Regulatory component	**Unit**	**Rates**
Natural Disaster Reserve (NDR)		
Natural Disaster Reserve (NDR)	$/month	2.42
Interim Income Tax Rate Adjustment (ITA)		
July - Dec.	%	-9.03%
Tax		
tax rate	%	1.50%

Note: Assumed power factor = 0.9.

7.1.2 ComEd

Figure 42. ComEd's rate schedule

Electricity component	Unit ($CAN)	Rates
Energy charge		
rates vary across months	$/kWh	0.03371 - 0.05106
Capacity charge		
2017/2018 Planning Reserve Auction	$/kW-month	4.68
2018/2019 Planning Reserve Auction	$/kW-month	8.39
Delivery component	**Unit**	**Rates**
Customer Charge	$/month	753.56
Standard Metering Charge	$/month	36.71
Distribution Facilities Charge	$/kW	7.36
Primary Voltage Transformer Charge	$/kW	0.39
IL Electricity Distribution Charge	$/kWh	0.00155
Regulatory component	**Unit**	**Rates**
Transmission Services Charge (PJM services)		
Jan. - May	$/kWh	0.01742
June - Sept.	$/kWh	0.01706
Oct. - Dec.	$/kWh	0.00963
Environmental Cost Recovery Adjustment		
Jan. - Mar.	$/kWh	0.00062
Apr. - Dec.	$/kWh	0.00043
Renewable Portfolio Standard		
Jan. - May	$/kWh	0.00122
June - Dec.	$/kWh	0.00185
Zero Emission Standard	$/kWh	0.00250
Energy Efficiency Programs	$/kWh	0.00013
Franchise Cost		
Franchise Cost, Jan. - May	%	1.95%
Franchise Cost, June - Dec.	%	2.06%
State Tax		
for the first 2,000 kWh used in a month	$/kWh	0.00429
for the next 48,000 kWh used in a month	$/kWh	0.00415
for the next 50,000 kWh used in a month	$/kWh	0.00394
for the next 400,000 kWh used in a month	$/kWh	0.00386
for the next 500,000 kWh used in a month	$/kWh	0.00372
for the next 2,000,000 kWh used in a month	$/kWh	0.00351
for the next 2,000,000 kWh used in a month	$/kWh	0.00330
for the next 5,000,000 kWh used in a month	$/kWh	0.00303
Municipal Tax		
for the first 2,000 kWh used in a month	$/kWh	0.00734
for the next 48,000 kWh used in a month	$/kWh	0.00484
for the next 50,000 kWh used in a month	$/kWh	0.00436
for the next 400,000 kWh used in a month	$/kWh	0.00417
for the next 500,000 kWh used in a month	$/kWh	0.00398
for the next 2,000,000 kWh used in a month	$/kWh	0.00373
for the next 2,000,000 kWh used in a month	$/kWh	0.00358
for the next 5,000,000 kWh used in a month	$/kWh	0.00345

Note: Assumed energy charge to be monthly wholesale energy prices in Illinois; assumed capacity charge to be capacity auction clearing price for Zone 5 (Illinois) in MISO; assumed regulatory charges based on riders in ComEd's rate schedule.

7.1.3 NIPSCO

Figure 43. NIPSCO's rate schedule

Electricity component	Unit ($CAN)	Rates
Energy charge		
up to and including 450 hours of the billing demand	$/kWh	0.05434
in excess of 450 hours up to and including 500 hours	$/kWh	0.11107
in excess of 500 hours	$/kWh	0.19679
(high load) up to and including 600 hours of the billing demand	$/kWh	0.05157
(high load) in excess of 600 hours up to and including 660 hours	$/kWh	0.04741
(high load) in excess of 660 hours	$/kWh	0.04611
Rider 770 fuel cost		
rates vary across months	$/kWh	(0.00535) - 0.00341
Delivery component	**Unit**	**Rates**
Demand charge		
industrial	$/kW	13.18
high load industrial	$/kW	20.38
Regulatory component	**Unit**	**Rates**
Rider 771 - RTO		
771 - RTO - Industrial	$/kWh	0.00057 - 0.00236
771 - RTO - HL Industrial	$/kWh	0.00080 - 0.00218
Rider 772 - Environmental cost		
772 - Environmental cost - Industrial	$/kWh	(0.00001) - 0.00283
772 - Environmental cost - HL Industrial	$/kWh	0.00269 - 0.00304
Rider 774 - Charges for Resource Adequacy		
774 - Charges for Resource Adequacy - Industrial	$/kWh	0.00153 - 0.00686
774 - Charges for Resource Adequacy - HL Industrial	$/kWh	0.00020 - 0.00207
Rider 783 - Adjustment for Charges for DSMA		
783 - Adjustment for Charges for DSMA - Industrial	$/kWh	0.00990 - 0.00999
783 - Adjustment for Charges for DSMA - HL Industrial	$/kWh	0
Rider 786 - Green Power		
786 - Green Power - Industrial	$/kWh	0.00235 - 0.00382
786 - Green Power - HL Industrial	$/kWh	0.00235 - 0.00383
Rider 787 - Adjustment of Charges for Federally Mandated Costs		
787 - Adjustment of Charges for Federally Mandated Costs - Industrial	$/kWh	0 - 0.00080
787 - Adjustment of Charges for Federally Mandated Costs - HL Industrial	$/kWh	0 - 0.00059
Rider 788 - Transmission/ Distribution/ Storage		
788 - Transmission/ Distribution/ Storage - Industrial	$/kWh	(0.00196) - 0.00143
788 - Transmission/ Distribution/ Storage - HL Industrial	$/kWh	0.00043 - 0.00086
State tax rate	%	7%

Note: "HL" stands for "high load"; industrial rate schedule was used for load profile 1, and HL industrial rate schedule was used for load profiles 2 - 4.

7.1.4 DTE Electric Company

Figure 44. DTE's rate schedule

Electricity component	Unit ($CAN)	Rates
Demand charge		
Jan. - Apr.	$/kW	20.53
May - July (capacity)	$/kW	15.43
May - July (non capacity)	$/kW	6.68
Aug. - Dec. (capacity)	$/kW	14.31
Aug. - Dec. (non capacity)	$/kW	7.79
Energy charge		
Jan. - Apr. (on-peak)	$/kWh	0.05629
Jan. - Apr. (off-peak)	$/kWh	0.04329
May - July (on-peak)	$/kWh	0.05649
May - July (off-peak)	$/kWh	0.04349
Aug. - Dec. (on-peak)	$/kWh	0.05395
Aug. - Dec. (off-peak)	$/kWh	0.04095
Delivery component	**Unit**	**Rates**
Subtransmission and transmission service charge	$/month	357.50
Distribution charges		
Jan. - Apr.	$/kW	5.148
May - July	$/kW	4.901
Aug. - Dec.	$/kW	4.641
Regulatory component	**Unit**	**Rates**
Power Supply Cost Recovery (PSCR) Clause	$/kWh	0.00113
Nuclear surcharge		
Jan. - Apr.	$/kWh	0.00095
May - Dec.	$/kWh	0.00099
Energy Waste Reduction Surcharge (EWRS)		
Jan. - Apr.	$/meter/month	54.665
May - Dec.	$/meter/month	71.201
Transitional Recovery Mechanism (TRM) terminated 2019		
Jan. - Apr.	$/kWh	0.00176
Oct. - Dec.	$/kWh	0.00175
U-18255 IS Implementation Surcharge, Jan - Mar., May	$/kWh	0.00246
U-18014 SIR Self- Implementation Refund, Apr.	$/ customer	-51.311
LIEAF Factor	$/ billing meter	1.209
Sales tax	%	6%

Note: Industrial process can be exempt from sales tax; in the billing calculation, we assumed 10% of the bill is taxable.

7.2 Response to feedback

Why does the report not discuss a nine cent rate or a flat rate?

LEI has seen no empirical evidence that a nine cent rate reflects system costs or customer impact. LEI has based its analysis on existing costs, targeted relief, and incentives compatible rate design. LEI does not believe that flat rates are appropriate in rate designs; time of use rates better reflect the system impact of users.

Why does the report not simply recommend to reduce the GA?

The GA represents the cost of provincial commitments to energy producers and programs net of wholesale energy market offsets. Some of these payments revert to provincially-owned entities like OPG. To reduce the GA would require either breaking some of these commitments or shifting the responsibility for paying them to taxpayers. Counterparties to the contracts underlying the GA represent a range from large developers to small businesses; in many cases the higher cost contracts may be with local farmers or small-scale entrepreneurs. Cancelling such contracts unilaterally would cause hardship to smaller investors and prompt larger ones to question Ontario as a stable investment destination.

Why use OEFC to administer the IRRI?

The OEFC is mentioned as an example of the type of entity that could be used. The objective is to have an entity which is at arm's length from the Ministry, to reduce perceptions of political interference, and also at a distance from the IESO, so as not to prompt suspicions of conflict of interest by both operating a market and assisting a customer class in reducing costs associated with that market. OEFC or any other entity would need to be staffed up to perform the added functions envisioned under the IRRI. However, some of the workload could be contracted out, similar to the way that review of various applications to the former Ontario Power Authority ("OPA") was.

Have you considered NIER?

> *"The NIER program assists Northern Ontario's largest industrial electricity consumers to reduce energy costs, sustain jobs and maintain global competitiveness. The NIER program is part of the government's plan to strengthen the economy and support a dynamic and innovative business climate that attracts investment and helps create jobs"*
>
> Source: Ontario ENDM

The Northern Industrial Electricity Rate ("NIER") Program, administered by the Ministry of Energy, Northern Development, and Mines ("ENDM"), provides eligible large industrial customers in Northern Ontario with electricity price relief. The current version of the program was launched in April 2017 and will operate until March 2022. Qualified participants receive electricity cost rebates of 2¢/kWh, with individual rebates capped at the lower of $20 million or certain predefined consumption levels (e.g. 2013-2016 average consumption levels). According to ENDM, the NIER program can reduce electricity prices for participating industrial customers by 25% on average. The NIER is a discretionary, non-entitlement program funded through provincial revenues, and subject to participants meeting and maintaining all eligibility and program requirements. The total spending limit is $120 million per fiscal year (subject to approval of annual program funding).[55]

Some aspects of NIER are consistent with the proposed CILRB program. Like NIER, the CILRB program is targeted, time-limited, and commitment-linked. However, the CILRB program would be available to a wider array of customers across the province. Participants in NIER would not be eligible for the CILRB program, and buydown awards would vary among applicants depending on their circumstances.

What about interruptible rates as an alternative to the ICI for those that volunteer?

While current demand response programs provide mechanisms and incentives similar to an interruptible rate, additional mechanisms could be explored. From the system's perspective, interruptible rates in place of the ICI for customers that **volunteer** could provide similar benefits. From the customer's perspective, consideration would need to be given to the comparative cost savings associated with interruptible rates (compared to the ICI), as well as the cost interruptions could have on their operations.

Could you consider reducing allowed returns for regulated businesses, or examining returns in the contracts that make up the non-regulated portion of the GA?

No. The allowed returns for the regulated businesses are consistent in magnitude and methodology with those found across North America, and reflect the concept of "just and reasonable" rates intended to produce a return similar to that of a competitive business facing an equivalent level of risk. Reducing allowed returns would impair the ability of the regulated businesses to raise capital and maintain investment at levels required to maintain safety and reliability. Such underinvestment would ultimately be detrimental to customers.

With regards to the non-regulated portion of the GA, examining returns in such projects would require re-opening contracts. Forcing renegotiation of contracts would reduce the attractiveness of Ontario as an investment destination, as investors may fear that what happens in one sector can occur in another; any company with government contracts where profits are perceived as "high" could potentially face the same fate. Furthermore, there is nothing untoward about returns to unregulated businesses being higher than those of regulated businesses, consistent with risk. Unlike regulated businesses, independent power producers ("IPPs") cannot pass through most costs to consumers; they cannot go to the regulator to ask for funding for repairs if equipment fails; and any successful project is the result of development of prospects across several sites, the remainder of which may never come to fruition. For all these reasons, IPPs require a higher return than they would if they were under a regulated rate. In return, however, ratepayers benefit from the reallocation of risk – developers whose projects fail lose their shareholder's money; they cannot pass through the costs of the failure on electricity bills.

[55] Ontario Ministry of Northern Development and Mines. *Northern Industrial Electricity Rate Program (NIER Program) - Program Rules*. June 20, 2017.

Why should the support be targeted?

Current rate levels are not the result generally of poor rate design; instead, they are the result of significant investments made in the system. While those investments may have been more expensive than they needed to be, current rates reflect actual system costs, were developed based on broadly accepted rate design principles, and are transparent. No rate class has an entitlement to rates set in relation to other jurisdictions. Rate support is not free; funds used for rate support could have been deployed in different ways in the economy. Given this fact, funds need to be deployed wisely. Investing funds in reducing rates to customers who are largely indifferent is wasteful; failure to target funds to those for whom the rate support has the greatest impact will over time reduce Ontario's competitiveness. By making support time limited and commitment linked, the province can monitor impact and calibrate programs. ReCharge NY and Tariff L, covered subsequently, are examples of targeted support programs or programs with targeted elements.

How does the proposal compare to ReCharge NY? Tariff L?

Both ReCharge NY and Quebec's Tariff L conform to some or all of the principles of the CILRB program. Both are targeted, time-limited, and to a greater or lesser degree, commitment-linked. ReCharge NY has a long list of evaluative criteria and is a competitive program; Quebec's program focuses on large industrial customers. Below, we briefly describe each program.

7.2.1 ReCharge NY

New York's ReCharge NY ("RNY") program offers qualifying businesses and nonprofits the opportunity to lower their energy costs by up to 25%. Cost reductions are made possible through specially allocated New York Power Authority ("NYPA") power (901 MW of capacity from its own supply and power purchases from the market) that is set aside by the state government and NYPA Board for economic support. The program is open to most businesses and nonprofit organizations, with over 700 businesses receiving lower-cost power through the program.[56]

Power contracts are awarded on a competitive basis for a period of up to 7 years. To receive allocated power, companies must make commitments such as remaining in the state, maintaining or growing employment, expanding operations, and/or investing significantly in local businesses. The RNY program is "meant to attract, keep, and grow businesses throughout" the state and "supports job creation and retention for existing, expanding or new businesses and nonprofits." [57]

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[56] The program is not open to retail businesses, sports venues, gaming or entertainment-related establishments, and places of overnight accommodation.

[57] All information based on NYPA's description of the RNY program accessible at: https://www.nypa.gov/innovation/programs/recharge-ny

ReCharge NY applications are evaluated according to:

- Significance of the cost of electricity to applicant's total cost of doing business and the impact an allocation would have on the applicant's operating costs;
- New capital investment in New York State resulting from an allocation;
- Type and cost of buildings, equipment and facilities to be constructed, enlarged or installed;
- Extent to which an allocation would be consistent with existing regional economic development strategies and priorities;
- Applicant's payroll, salaries, benefits and number of jobs at the facility receiving an allocation;
- Number of jobs created or retained within New York State;
- Applicant's risk of closure, curtailing facilities or operations, relocating out of state, or losing jobs in the state;
- Significance of applicant to the local economy;
- Extent of applicant's investment in energy efficiency measures;
- Whether applicant receives a NYPA hydropower allocation or benefits supported by the sale of NYPA hydropower;
- The extent to which an allocation would result in an advantage relative to the applicant's competitors within the state; and
- For not-for-profits, the significance of the critical service or substantial benefits to the local community.

7.2.2 Tariff L

Rate L is Hydro Quebec's ("HQ") industrial rate for large power consumers. It applies to annual contracts with a minimum billing demand of 5,000 kW that are principally related to an industrial activity. The cost of energy under Rate L is a flat ¢3.28/kWh, and the demand charge is $12.90/kW-month.

Customers with Rate L contracts also have access to a number of offerings from HQ, including (but not limited to):

- *interruptible electricity options,* providing eligible customers credits if they choose to participate in winter load shaving/curtailment;
- an *industrial revitalization rate*, where qualified customers can return unused production capacity to operation or to convert an industrial process that is currently powered by fossil fuels to electricity, with supplementary electricity charged at avoided electricity costs (subject to a minimum of ¢3.28/kWh); and
- an *economic development rate*, which provides qualified customers a 20% rate reduction if they are "planning to build and commission a **new** facility **or expand an existing** facility operating in a promising growth sector." To qualify, new load must be at least 1,000 kW, while expanding load must be at least 500 kW and correspond to at least 10% of current contracted load. Other eligibility criteria exist, including for example that electricity costs for the facility must account for at least 10% of total operating expenses. Projects will be

evaluated based on application criteria, the project's added value, and economic benefits to the province (with aid provided by government in assessing economic growth contribution of projects). The economic development rate will end in 2027, with the rate reduction of 20% diminishing by 5% points a year over the final three years.[58]

In addition, the provincial government launched a program in 2016 meant to **promote investments in the manufacturing and natural resource processing sections, and stimulate capital investment** by eligible large industrial Rate L customers. Under this electricity discount program, eligible companies can receive assistance (in the form or electricity cost reductions), which can effectively enable them to recover up to 50% of eligible project costs, through the reimbursement of 40% of eligible costs incurred, and an additional reimbursement of up to 10% of eligible costs for projects aimed at emissions intensity reductions. Under this program, the maximum electricity bill reduction is 20% over a maximum period of four years; if the eligible investment projects are $250 million or more, the maximum period is extended to six years.[59]

Why isn't the voluntary program just a feel-good green energy program?

The purpose of the program is not to incentivize more green power to be built. It is not funded through rates or taxes, nor does it rely on carbon pricing. Instead, it makes it more difficult for environmentally minded consumers to claim green credentials without contributing to the cost. Green branding is perceived as valuable; however, large manufacturers and industrial companies may receive less benefit from such branding than other entities, such as consumer goods and retail companies. A voluntary REC program allows participants to brand themselves as 100% green and contribute a greater share to the existing costs of Ontario's nearly emissions-free grid. Setting such a program up is not difficult, nor need it be particularly costly; production from the eligible units is already tracked and REC registry software can be easily attained, or Ontario generation could be added to existing REC tracking programs.

Why include the Hydro Prudency Pledge?

The GA is the main cost driver of differences in rates between Ontario and other North American jurisdictions. In turn, government decisions are the primary driver of the size of the GA. Consequently, we need to address both the impact of previous government decisions, and work towards assuring future government decisions do not make the situation worse.

How does Ontario's industrial consumption compare to residential and commercial?

As shown in Figure 45, Ontario's main consumers fall into three groups: residential, commercial, and industrial, with most industrial consumption being associated with manufacturing. Ontario's total consumption over the past two decades has increased, growing at a compound annual

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58 All information based on Hydro Quebec's overview of Rate L, accessible at: http://www.hydroquebec.com/business/customer-space/rates/rate-l-industrial-rate-large-power-customers.html#

59 All information based on the Quebec Ministère des Finances summary of the *electricity discount program applicable to consumers billed at Rate L*, accessible at: http://www.finances.gouv.qc.ca/en/Department677.asp

growth rate ("CAGR") of 0.84% from 1998 to 2017, as presented in Figure 46. This growth was associated mostly with commercial and other institutional consumption, and partially with residential consumption. Industrial load associated with manufacturing, however, has declined at a CAGR of -0.92% over the same period.

Figure 45. Electricity use by customer class (2017)

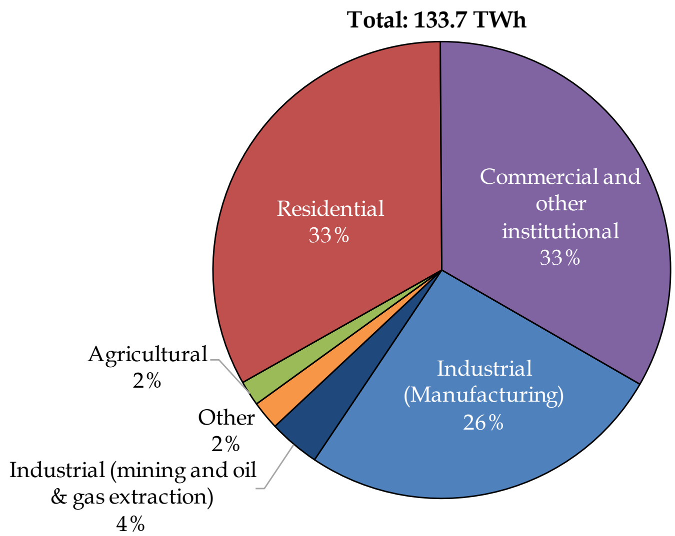
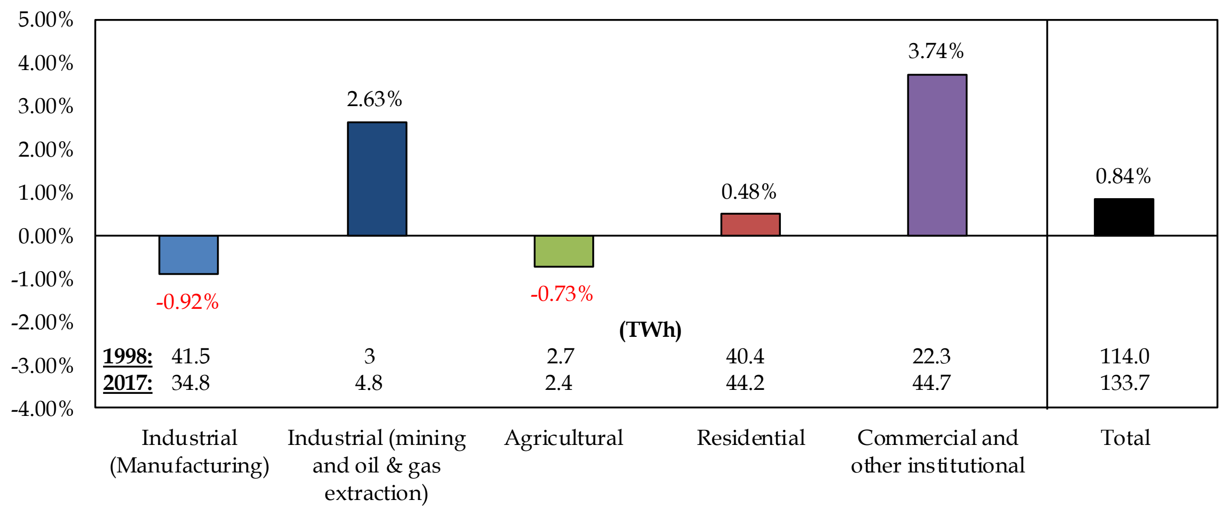


Figure 46. Compound annual growth rate in annual consumption (1998 to 2017)



Note: Based on Statistics Canada data, which may not exactly match data from the IESO. For example, based on data from the IESO's 2016 OPO, residential consumption in 2015 was 52 TWh, commercial was 51 TWh, and industrial was 35 TWh (36%, 36%, and 24% respectively of total). While total consumption by type may differ based on the source, the conclusion that these are the three main consumption groups does not.

Source: Statistics Canada. *Table 25-10-0030-01 Supply and demand of primary and secondary energy in natural units.*

While these three groups make up the majority of consumption, they do exhibit different load patterns. Aggerated residential and commercial consumption would typically exhibit a greater degree of seasonality, variability between months, and variability between hours – driven by consumption habits and weather conditions.

To get a sense of this difference, Figure 47, Figure 48, and Figure 49 present respectively: monthly peak, monthly consumption, and the average hourly demand shape for two aggerated consumption groups in 2018. The first group, "large industrials", uses the hourly data on aggregated large industrial consumption provided by AMPCO as a non-exhaustive proxy for industrial consumption. The second group, "all other consumption", uses the IESO's data on hourly Ontario demand less AMPCO's hourly aggregated large industrial load data. By removing large industrial consumption from Ontario's total demand, the remaining amount is largely made up of residential and commercial load.

As can be seen in the figures, the group consisting of "all other consumption" (made up mostly of residential and commercial) exhibited a more pronounced amount of seasonal, monthly, and hourly variability. In comparison, the aggregated industrial consumption group exhibited relatively flat monthly peaks and monthly consumptions, and average hourly demand that declined during peak hours.

Figure 47. 2018 monthly peak demand (MW)

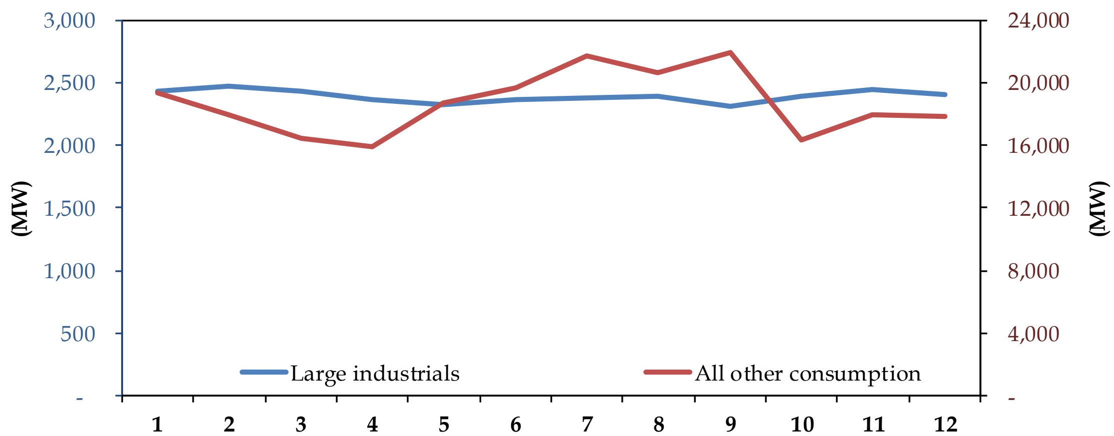
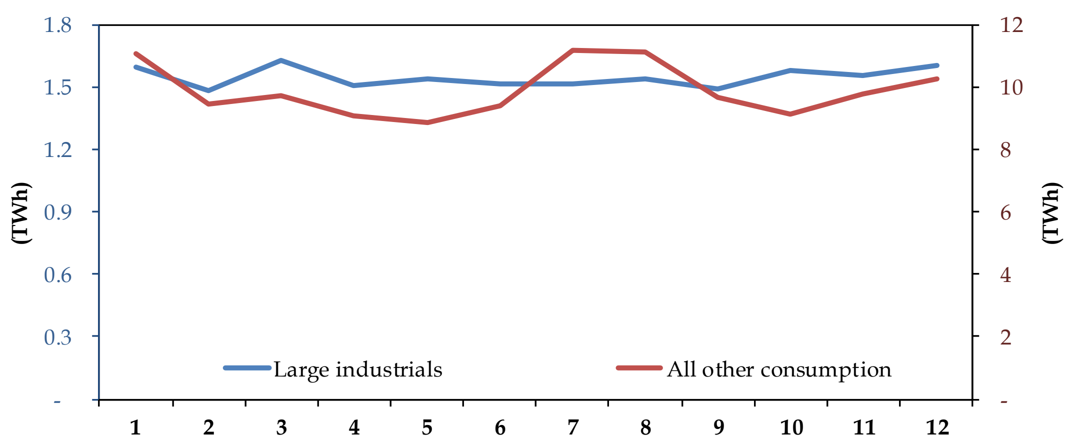
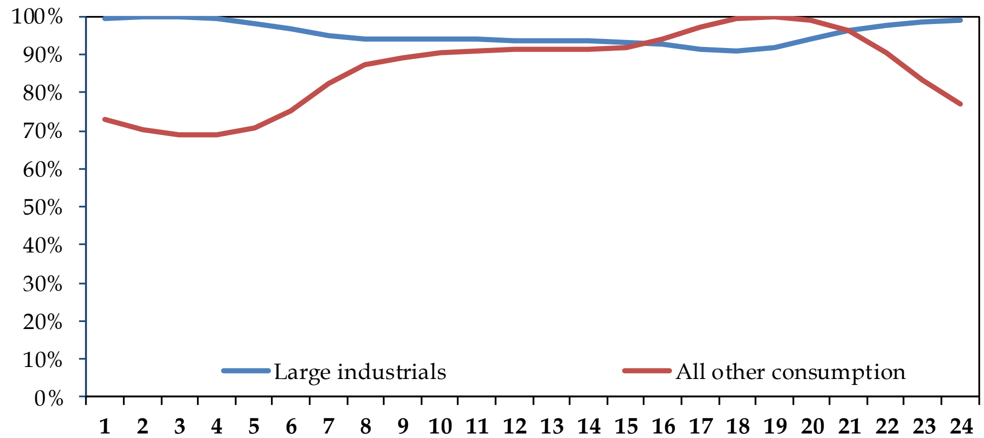


Figure 48. 2018 monthly consumption (TWh)



Source: LEI analysis using AMPCO and IESO data

Figure 49. 2018 load shape based on average hourly demand (%)



Source: LEI analysis using AMPCO and IESO data

Why was the IMPLAN model chosen to conduct the macroeconomic analysis and where else has it been used?

There are a limited number of macroeconomic models capable of conducting the analysis required for this study that are available for use. IMPLAN's proprietary input-output model has been used to conduct a wide number of economic studies in jurisdictions across Canada. These include:

The Brattle Group. *Employment and Economic Benefits and Transmission Infrastructure Investment in the U.S. and Canada.* 2011. <http://www.capx2020.com/media/WIRES_study/WIRES_jobs_study_05.2011.pdf>

Bureau of Business and Economic Research. *Enbridge Pipeline Construction Economic Impact Study.* April 18, 2017. <http://www.apexgetsbusiness.com/media/userfiles/subsite_159/files/Enbridge%20Line%203%20Impact%20Study%20-%20April%202017(2).pdf>

Canadian Energy Research Institute. *Economic Impacts of New Oil Sand Projects in Alberta (2010-2035).* May 2011. <http://www.americanpetroleuminstitute.net/~/media/Files/News/2011/Economic_Impacts_of_New_Oil_Sands_Projects_Alberta.pdf>

Chen, Xi. *Economic and Environmental Impacts of Biofuel Policy in Canada: An Application of Input-Output Modelling.* July 2015. <http://digitool.library.mcgill.ca/webclient/StreamGate?folder_id=0&dvs=1510704718628~251>

Deloitte. *Economic Impact Study on the Ontario Veterinary College at the University of Guelph.* 2014. <https://ovc.uoguelph.ca/doc/economic/OVC-Economic-Impact-Study.pdf>

Frank, Rimerman + Co. LLP. *The Economic Impact of the wine and grape industry in Canada.* 2015. <http://www.canadianvintners.com/wp-content/uploads/2017/06/Canada-Economic-Impact-Report-2015.pdf>

Ontario Corn Producers' Association. *The Economic Importance of Ontario's Corn Sector.* December 2005. <https://www.ridgetownc.com/research/documents/vyn_Impact_of_Corn_Report.pdf>

Across North America more broadly, the following sample of reports use IMPLAN:

Bureau of Business and Economic Research. *The Economic Impact of the Canada/Northeastern Minnesota Relationship on the Arrowhead Region of Minnesota.* June 30, 2016. <https://lsbe.d.umn.edu/sites/lsbe.d.umn.edu/files/canada_minnesota_connection_report_final.pdf>

Henneberry, S., Whitacre, B., and Agustini, H. *An Evaluation of the Economic Impacts of Oklahoma Farmers Markets.* 2008. <http://ageconsearch.umn.edu/bitstream/99760/2/Evaluation%20pg%2064-78.pdf>

Massachusetts Energy Storage Initiative Study. *State of Charge.* 2016. <http://energystorage.org/system/files/attachments/ma_storage_study.final_w5768299x7ac2e.pdf>

Midcontinent Independent System Operator. *Economic Impact of MTEP In-service Projects from 2002-2015.* July 2015. <https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Economic%20Impact%20of%20MTEP%20In-Service%20Projects.pdf>

Minnesota Power. *Minnesota Power/Manitoba Hydro Great Northern Transmission Line Economic Impact on Northern Minnesota.* July 2013. <http://www.greatnortherntransmissionline.com/files/3713/7882/6435/MN_Power_Manitoba_Hydro_FINAL_July_2013.pdf.pdf>

National Renewable Energy Laboratory. *National Economic Value Assessment of Plug-In Electric Vehicles.* December 2016. <https://www.nrel.gov/docs/fy17osti/66980.pdf>

Can you comment on the recent OEB report on alternative price designs for GA recovery from non-RPP Class B customers?

The OEB's research paper on alternative price designs for Class B consumers focused on examining alternative approaches to the recovery of GA costs for Class B consumers.[60] Under

[60] All information based on the OEB Staff Research Paper entitled "Examination of Alternative Price Designs for the Recovery of Global Adjustment Costs from Class B Consumers in Ontario" (February 28, 2019). Available at: <https://www.oeb.ca/sites/default/files/rpp-roadmap-staff-research-paper-20190228.pdf>

the current structure, the GA is collected from RPP Class B customers through time-of-use rates. In contrast, non-RPP Class B customers pay a separate, flat volumetric charge that varies by month but not within the month. Therefore, non-RPP Class B customers face a "markedly weaker incentive to proactively manage their energy consumption relative to RPP consumers and Class A consumers alike."[61]

In the OEB's paper, a range of pricing prototypes for GA cost recovery are introduced and run through a simplified model to evaluate each prototype on a preliminary basis based on principles of revenue adequacy, economic efficiency, and consumer bill impacts. Based on this analysis, OEB staff conclude that an electricity price that charges consumers a GA price that is directly correlated to total Ontario electricity demand in each hour – labelled the demand-shaped prototype – yields the most positive results for electricity consumers.[62] Generally, the OEB notes that such changes "can generate moderate savings on average and individual savings for those consumers who can respond to price signals."[63]

While the concepts discussed by the OEB are sensible, overall they serve largely to reallocate who pays the GA rather than to reduce rates to consumers. Although the proposed changes are beneficial and should be pursued, they assist in deferring future capacity needs, and thus moderating future electricity costs, rather than addressing relatively high costs in the present.

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[61] OEB Staff Report page 1.

[62] Other prototypes assed were: Status Quo pricing; flat pricing; time-of-use pricing; supply-shaped pricing; and high-N pricing (where market costs are recovered through HOEP, and a fraction e.g. 50% of GA costs are recovered based on Class B consumption during highest demand hours within each cost recovery period).

[63] OEB Staff Report page 6.

7.3 Case study of Germany

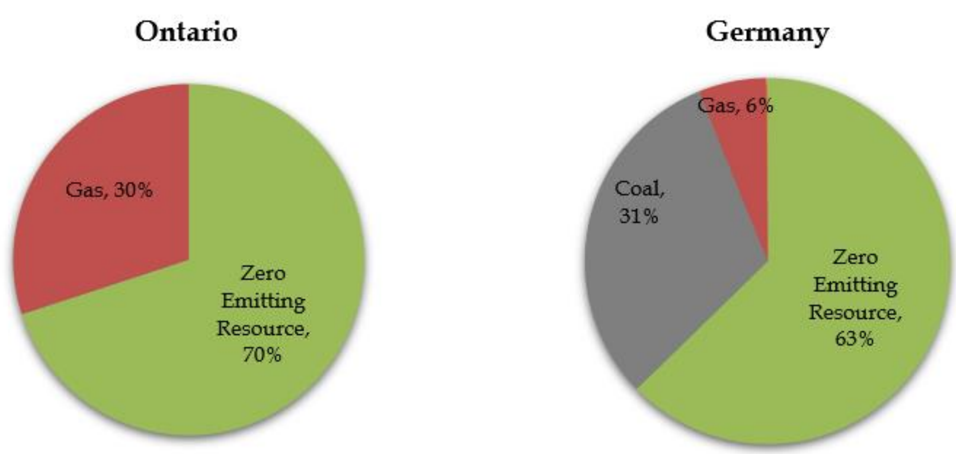
Germany serves as a comparative example for competitors to Ontario outside of North America. Key metrics between Ontario and Germany are shown in Figure 50. Germany's population is almost six time larger than Ontario's, while the land area is three times smaller, which makes the population density almost 18 times higher in Germany. Figure 51 shows the fuel mix for Germany and Ontario. Despite its efforts to increase the share of renewable energy sources, Germany's fuel mix still consists of 31% coal and 6% gas. Zero emitting resources (consisting of renewable resources including biomass and nuclear) make up the remaining 63%, compared to Ontario's 70% zero emitting resources share.

Figure 50. Key metrics comparison

Key metrics	Ontario	Germany
Real GDP growth, 2018	2.2%	1.5%
Population, estimates 2018	14,193,384	82,979,100
Land area, square kilometers	1,074,850	357,582
Average industrial rates, Canadian cents/kWh	9.6/13.6	13.7

Notes: Ontario's population estimate is for 2017; exchange rate used is CAN$ 1.5 = Euro 1.
Sources: Ministry of Finance, Ontario; Government of Ontario; Statistics Canada; Ontario industrial rates are estimated by LEI based on information contained in the Q3 2018 OER and the IESO's December 2018 monthly market report (for distribution-connected customer, including HST).

Figure 51. Supply fuel mix comparison, as of May 2019



Note: Zero Emitting Resource consists of renewable resources (including biomass) and nuclear.
Sources: Velocity Suite, Fraunhofer ISE.

7.3.1 Brief overview of Germany's "Energiewende"[64]

The so-called "Energiewende" literally means energy turnaround or energy transformation, and describes the country's planned transition from its coal-based power sector to a low-carbon,

[64] Clean Energy Wire. *A (very) brief timeline of Germany's Energiewende. Available at:* <https://www.cleanenergywire.org/factsheets/very-brief-timeline-germanys-energiewende>

nuclear-free economy. So far, policies have focused on the electricity sector and date back to the 1970s.

While the anti-nuclear movement was born in the 1970s, the Chernobyl disaster in 1986 triggered the first phase-outs of nuclear plants in the old German Democratic Republic ("GDR") in 1990 with Germany's reunification. That same year, the Federal Cabinet adopted its first emission reduction targets, 25% to 30% fewer CO_2 emissions by 2005, compared to 1987 levels. In 1991, the first renewables legislation was started, introducing feed-in tariffs for renewable power. In 2000, the Renewable Energy Act (Erneuerbare Energien Gesetz or "EEG") was passed, stipulating fixed feed-in tariffs and grid priority for renewables. Further, a nuclear phase-out was agreed with utilities for around 2022. In 2007, the EU defined climate targets for 2020 to be implemented by all member states: 20% of electricity to come from renewables, a 20% decrease in greenhouse gas emissions, and 20% more energy efficiency. In 2010, the German government set climate and renewable targets for 2020 and 2050 via the Energy Concept. Also in 2010, the government, then ruled by the conservative Christian Democratic Union ("CDU"), cancelled the nuclear phase-out, but it was re-introduced in 2011 shortly after the Fukushima disaster.

In 2014, feed-in tariffs under the EEG were lowered, and an auction system for solar PV capacity was introduced. In 2015, the Energiewende Monitoring Report showed that the 2020 emission target was likely to be "missed considerably." In 2016, utilities E.ON and RWE separated renewables from fossil fuel operations, while the carmaker Volkswagen's emission scandal triggered an increase in carmakers' step-up to electric mobility. The same year, the federal government agreed on its Climate Action Plan 2050, defining decarbonization targets for individual economic sectors. It aimed to power heating and transportation with renewable energy, with large implications for Germany's carmakers, freight industry, and gas companies.

In 2017, the renewables reform replaced fixed feed-in tariffs with auctions for renewables. Further, at the COP23 Climate Conference in Bonn, delegations negotiated a rulebook for the Paris Agreement from 2015. In 2018, the renewed grand coalition of the federal government gave up on the 2020 climate targets but raised the renewables expansion goal and announced the Climate Protection Law.

In the first half of 2018, renewable energy resources overtook coal as Germany's most important power source.[65] The government started a multi-stakeholder process to decide on the country's exit from coal, which in early 2019 was determined to be 2038.[66] Several uncertainties come with further renewable expansion, most importantly the lagging grid expansion as distributed, small-scale generation needs to be integrated, and fears of wavering supply security. The 20-year feed-

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65 Clean Energy Wire. *Renewables overtake coal as Germany's most important power source.* Available at: <https://www.cleanenergywire.org/news/renewables-overtake-coal-germanys-most-important-power-source>

66 Reuters. *Germany to phase out coal by 2038 in move away from fossil fuels*. Available at: <https://www.reuters.com/article/us-germany-energy-coal/germany-to-phase-out-coal-by-2038-in-move-away-from-fossil-fuels-idUSKCN1PK04L>

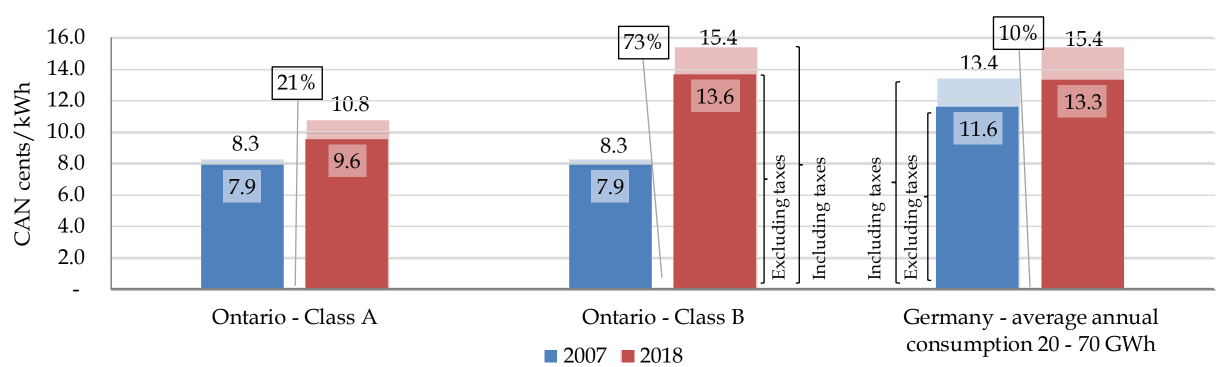
in tariffs from the early 2000s are about to expire, which could cause some of the renewable power capacity to go off the grid in the next few years.

7.3.1 Industrial electricity prices in Germany compared to Ontario

The policies introduced over the past few decades resulted in an increase in electricity prices both for households and industrial customers. Wholesale electricity prices on average have declined in recent years, but levies, taxes, and grid fees raised the bill especially for private households and small businesses. For a typical German household, the electricity rate including VAT (as this generally reflects the end price paid by household consumers) increased by 45% in local currency terms, from CAN¢30.2/kWh in 2007 to CAN¢45.8/kWh in 2018.

However, large industrial customers with an annual average consumption of 100 MWh and above are subject to special agreements with utilities and can negotiate significant reductions. For industrial customers with an annual average consumption of 20 to 70 GWh, which are comparable to the proxy load customers used as examples in this study, rates increased only moderately by 10% in local currency terms from 2007 to 2018, from CAN¢11.6/kWh in 2007 to CAN¢13.3/kWh in 2018. Figure 52 compares industrial electricity rates in Germany and Ontario on a pre-tax basis (post-tax rates also included for consistency with Figure 28). In 2007, German industrial rates for customers with an annual average consumption of 20 to 70 GWh were noticeably higher than Ontario rates, while in 2018 German rates continued to be higher than Ontario's for Class A customers but were very close to Class B customer rates. Considering the higher starting rate in 2007, electricity rates for industrial customers increased less in Germany than in Ontario from 2007 to 2018 but remained higher than the average rates seen by Ontario industrial customers in 2018.

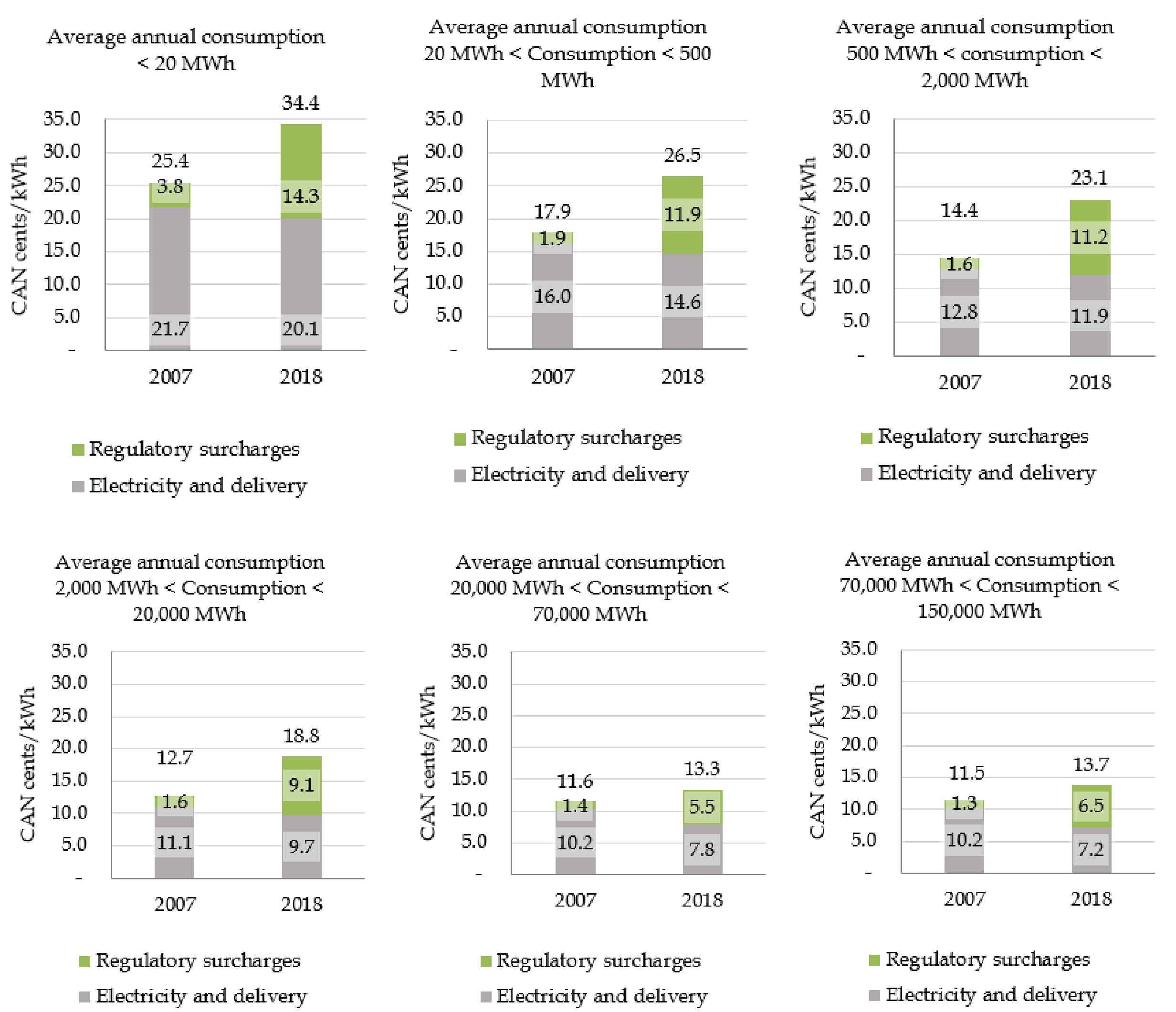
Figure 52. Electricity rates change for industrial customers, Ontario vs Germany, 2007 vs 2018



Notes:
(i) Exchange rate: 2007: CAN$1.46 = Euro 1; 2018: CAN$1.53 = Euro 1;
(ii) 2007 Ontario rates are from the OPA's "Delivered Electricity Price Comparison" [August 2008]. 2018 industrial rates are estimated by LEI based on information contained in the Q3 2018 OER and the IESO's December 2018 monthly market report (for distribution-connected customer) and IESO data on average HOEP, Class A GA, and Class B GA;
(iii) Percentage change shown above is based on the change of electricity rates in its original currency only, excluding the impact of exchange rate. Electricity rates exclude taxes, as it can be reclaimed in Germany for industrial customers. However, pre- and post-tax rates are shown here for consistency with Figure 28.
Sources: Eurostat Electricity prices for non-household consumers; OPA; IESO; Ontario Energy Report; IESO December 2018 Monthly Market Report; LEI analysis.

The increase in industrial rates in Germany was mainly driven by taxes and levies, while the electricity price excluding taxes and levies in fact declined. Figure 53 shows electricity rates for 2007 and 2018 for different consumption groups, broken down into electricity and delivery payments and taxes and levies, excluding VAT which can be reclaimed. For all groups, the increased share of renewable power sources pushed the wholesale electricity price down, while increasing taxes and levies, especially fixed feed-in tariffs, led to an overall increase in the electricity rates. This increase is far more pronounced for customers with consumption levels below 20 GWh per year. The larger the annual average consumption, the lower were both electricity and delivery rates as well as the regulatory component, showing the impact of companies' special contracts with utilities as well as exemptions from regulatory surcharges.

Figure 53. Breakdown of electricity rates change for German industrial customers, 2007 vs 2018



Notes:
(i) Exchange rate: 2007: CAN$1.46 = Euro 1; 2018: CAN$1.53 = Euro 1.
(ii) Industrial rates are given for all industrial customer groups as classified by Eurostat, excluding VAT.
Source: Eurostat. Electricity prices for non-household consumers.

7.3.2 Rate design in Germany

Within Germany, the rate design is generally the same across the country. It can be differentiated into an electricity component, delivery component, and regulatory component. While taxes and levies are regulated via federal law, the charges for the electricity and delivery component can vary across different utilities. Further, large industrial customers are eligible for reductions of certain taxes and levies. At an annual average consumption of 100 MWh and more, companies are considered "special contract customers" ("Sonderverträge"). Contract details are then negotiated directly between the industrial company and utilities and are not publicly available. Based on those contract agreements, industrial electricity rates vary widely, depending on how customers source their electricity, how much they consume from the grid, when they use it, and which levies, taxes and surcharges they are required to pay or are exempt from.

For a specific case study, LEI has selected the largest German utility by market share of both capacity and dispatched energy, RWE.[67] LEI selected the applicable rate schedule for industrial customers considering all regulatory requirements and exemptions according to size but disregarding any special conditions that a customer could potentially negotiate with the utility directly. This example intends to show a base case. Actual rates paid can be significantly lower, depending on the industrial customers load profile, usage, location, and individual agreements with the utility. RWE offers several contract variations for industrial customers with a consumption of 100 MWh per year and above: RWE Individual Business Strom, RWE Vario Business Strom, RWE Natur Business Strom, RWE Modular Strom, and RWE Portfolio-Management Strom.[68] In a 2015 study on industrial electricity rates, the Fraunhofer Institute assumed that one third of the long-term contracts are concluded with two years lead time, one third a year in advance, and one third during the given year.[69]

In terms of rate design types, industrial consumers have a two-part rate, including a capacity charge ($ per kW) and a volumetric charge ($ per kWh):

- capacity charge – $ per kW, based on the customer's highest 15-minute demand over the course of the year or month, depending on the rate contract chosen; and
- volumetric charge - $ per kWh, based on volumetric energy use; generally flat, but can be designed in a variety of forms via individual contracts including seasonal rates, time-varying rates, or agreements including demand response measures.

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[67] 26% of Germany's capacity and 32% of dispatched energy is owned by RWE. See Bundesnetzagentur Bundeskartellamt. *Monitoringbericht 2018*. Website. <https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Allgemeines/Bundesnetzagentur/Publikationen/Berichte/2018/Monitoringbericht_Energie2018.pdf;jsessionid=9603BD22AA9CEE2C9F7DA87787C403BC?__blob=publicationFile&v=5>

[68] Energiemarie. *Die RWE AG. Tarifangebote für Geschäftskunden mit einem Jahresverbrauch über 100 000 kWh.* Available at https://energiemarie.de/energieanbieter/rwe

[69] Fraunhofer Institute. *Electricity costs of energy intensive industries*. Available at: <https://www.isi.fraunhofer.de/content/dam/isi/dokumente/ccx/2015/Electricity-Costs-of-Energy-Intensive-Industries.pdf>

All industrial customers of 100 MWh and above are charged via "registered load measuring". A meter measures the load average for every 15 minutes. The total of all 15-minute load averages then gives the load per year. The registered load values are sent to the grid operator either in real time or the next day.

RWE's grid operator, Westnetz, generally differentiates into customers with an annual load utilization below 2,500 hours and equal or above 2,500 hours, which covers all industrial customers. Among industrial customers, it differentiates between low voltage, medium voltage, and high voltage. The delivery component is divided into a capacity and volumetric charge. Its capacity charge is based on the maximum integrated 15-minute capacity during each billing period.[70] The volumetric charge consists of a charge for energy consumed during the billing cycle. The electricity component as well as all parts of the regulatory component are volumetric charges. All taxes and levies are defined on an annual basis by the federal government.

Figure 54 presents the detailed rate schedules that were used in the exemplary billing calculation. This rate schedule does not consider any special agreements that customers with an annual consumption of 100 MWh or more can negotiate with utilities, which may lead to significant rate reductions.

The federal government only receives revenues from the two taxes (value-added tax and electricity tax) and the concession fee only. The other surcharges go to grid operators, renewable power producers, and conventional power generators.

The Renewable Energy Act ("EEG") makes up the biggest portion of the regulatory component. It is intended to finance the increase in renewables via guaranteed feed-in-tariffs, but the actual surcharge level is also driven by other factors. According to the Federal Association for Renewable Energy (Bundesverband Erneuerbare Energien or "BEE"), the share of the EEG surcharge directly dedicated to the support of renewable energy was 42% in 2015, while the reduction in wholesale electricity prices accounted for 23% and privileges for industrial customers accounted for 20%. Similar to the relationship between HOEP and the GA in Ontario, decreasing wholesale electricity prices increased the amount that needs to be covered for the guaranteed feed-in-tariffs. As for the privileges for industrial customers, according to the Federal Office of Economics and Export Control (Bundesamt für Wirtschaft und Ausfuhrkontrolle or "BAFA"), a total of 2,154 industrial customers were exempt from the renewable energy surcharge in 2015. This number increased to 2,209 in 2018, accounting for about one fifth of the national electricity consumption.[71] The BEE calculated that those customers without exemptions paid $7.06 billion to cover the subsidies for industrial customers in 2014, which is equivalent to ¢1.84/kWh. An average household with an annual consumption of 3,500 kWh paid $323 for

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[70] Westnetz. *Netzentgelte Strom*. Available at: https://iam.westnetz.de/ueber-westnetz/unser-netz/netzentgelte-strom

[71] pv magazine; *Mehr als 2200 Unternehmen beantragen teilweise Befreiung von EEG-Umlage*. Available at: <https://www.pv-magazine.de/2018/08/20/mehr-als-2200-unternehmen-beantragen-teilweise-befreiung-von-eeg-umlage/>

the renewable energy surcharge in 2014, of which the BEE attributed $65 to allowances for industrial customers.[72]

Figure 54. RWE power's rate schedule for 2018

Electricity component	Unit ($CAN)	Rates
Charge for energy		
Generation and Sale	$/kWh	$ 0.0716
Delivery component	**Unit ($CAN)**	**Rates**
Charge for capacity		
Grid charges - capacity charge measured for highest 15-minutes during year or month, depending on contract*	$/kW	$ 124.8
Charge for energy		
Grid charges - energy component**	$/kWh	$ 0.0106
Regulatory component	**Unit ($CAN)**	**Rates**
Taxes and levies		
Renewable Energy surcharge	$/kWh	$ 0.0980
Renewable Energy surcharge, lowest for non-ferrous metal producers	$/kWh	$ 0.0008
Renewable Energy surcharge, lowest for all others	$/kWh	$ 0.0015
Concession fee	$/kWh	$ 0.0017
CHP surcharge to to fund a guaranteed price for combined heat and power (CHP) plants, paid on grid charges	$/kWh	$ 0.0043
Network access surcharge for first 1,000,000 kWh	$/kWh	$ 0.0047
Network access surcharge for above 1,000,000 kWh	$/kWh	$ 0.0008
Network access surcharge for above 1,000,000 kWh and IF producing industry or rail transportation and electricity costs were 4% of prior year's revenue	$/kWh	$ 0.0004
Offshore liability surcharge (most industrial customer are exempt)	$/kWh	$ 0.0064
Demand response surcharge	$/kWh	$ 0.0001
Electricity tax	$/kWh	$ 0.0314
Electricity tax for manufacturing, agriculture, forestry	$/kWh	$ 0.0236
Value Added Tax		
VAT	%	16%

* The capacity charge depends on the annual load profile. For customers with peak months, a monthly charge is more beneficial. For customers with a rather stable load profile, the annual charge is more beneficial. The rate applies to industrial customers connected to the grid at medium voltage (3-30V).
** The example provided applies to industrial customers connected to the grid at medium voltage (3-30V).
Sources: Westnetz Netzentgelte, Bundesnetzagentur, Energiemarie RWE AG, Stadtwerke Neuss Preisvereinbarung.

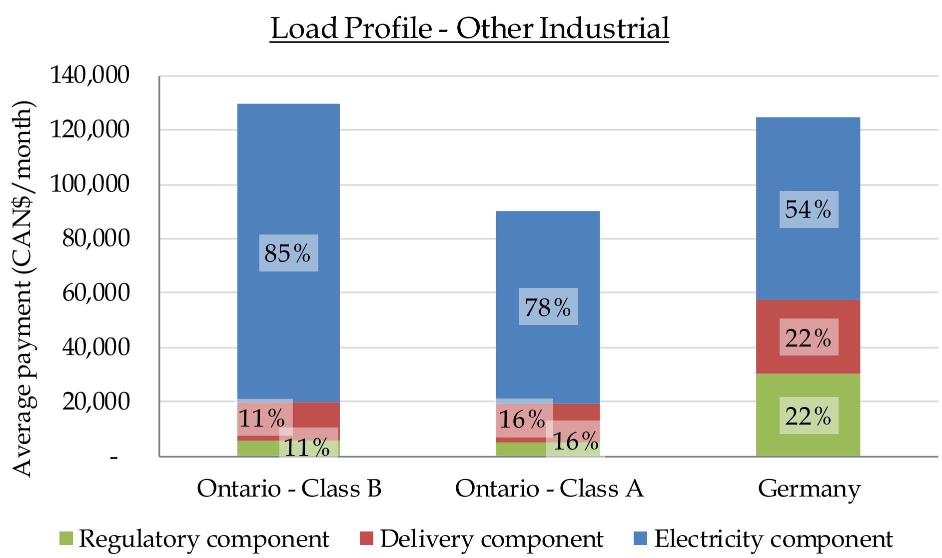
LEI estimated a typical monthly bill for each proxy customer based on their load profiles and rate schedules in 2018. Figure 55 shows the typical monthly bills in Germany compared to Ontario. In general, all of the proxy customers would have higher monthly bills in Germany than in Ontario,

[72] Stromreport Zahlen Daten Fakten. *EEG Umlage*. Available at: <https://iam.westnetz.de/ueber-westnetz/unser-netz/netzentgelte-strom>. Costs were translated from Euro into CAN$ at the 2014 exchange rate of CAN$ 1.47 = 1 Euro.

with the difference becoming significant for Ontario Class A customers. While the electricity and delivery component are also higher in Germany, the regulatory component is the driving force for the price difference. Before considering any "special contracts", 22-23% of German industrial customers' electricity charges are related to the regulatory component, while this component only makes about 5-11% for Ontario's industrial customers.[73]

As shown in Figure 55, for the Other Industrial load profile, Germany's modeled bill is 4% lower than that of the same customer in Ontario facing Class B rates, and 38% higher than that of the same customer facing Class A rates.

Figure 55. Typical modeled monthly bill in 2018 in Germany vs Ontario, Other Industrial



As can be seen in Figure 56 and Figure 57, the bill estimates for the Metals Manufacturing and Motor Vehicle Manufacturing loads come to almost the same amount in Germany, as both profiles have very similar annual peak loads and consumption levels and are subject to very similar surcharge reductions as specified by regulations. In contrast, these two proxy customers would face more differentiated bills in Ontario due to their respective load shifting abilities at system peaks and associated Class A GA costs. Comparatively, Germany's modeled typical bills are higher than Ontario's for these proxy customers: 69% higher for the Metals Manufacturing proxy load, and 30% higher for the Motor Vehicle Manufacturing load.

It is important to note that these illustrative industrial profiles for Germany do include all regulatory components and related surcharge reductions but do not consider any special contract conditions, which could include load shifting agreements, a reduced electricity component etc. Based on data from the European Commission, actual paid industrial rates for customers between

[73] Some of what is accounted for in the regulatory component for German rates is accounted for in the GA for Ontario, which in modeled rates is part of the electricity component.

20 and 50 GWh per year in 2018 were significantly lower than what our illustrative bills show, as can be seen in Figure 52.

Figure 56. Typical modeled monthly bill in 2018 in Germany vs Ontario, Metal Manufacturing

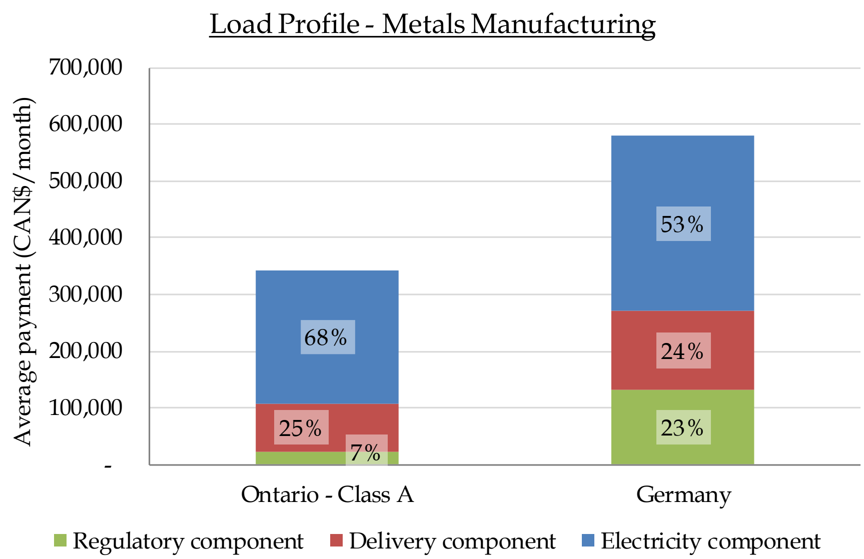
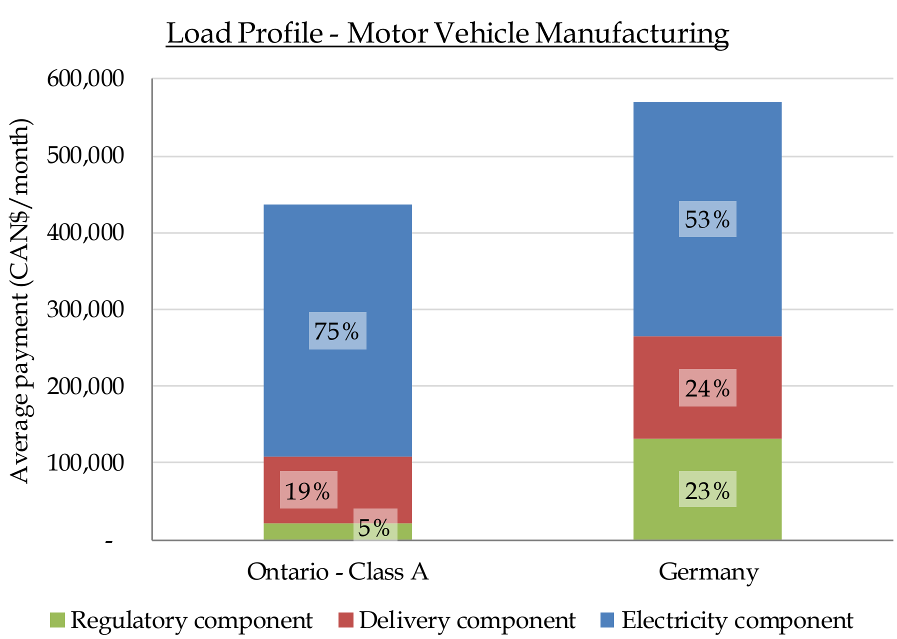


Figure 57. Typical modeled monthly bill in 2018 in Germany vs Ontario, Motor Vehicle Manufacturing



The key takeaway from the German case study centers around exemptions from renewable energy surcharges, and the ability for special contracts to be negotiated between utilities and industrial customers, which can reduce industrial rates significantly. While general regulatory surcharges can support policy goals, exemptions and special contracts can reduce industrial customers' bills and help utilities with annual planning through load shaving and energy efficiency agreements with large customers. However, studies suggest that to cover for industry exemptions from renewable energy surcharges, in the German case as much as ¢1.84/kWh may have been shifted away from industrial consumers onto other consumer groups.

7.3.3 Observations

In summary, LEI has the following observations:

- Modeled typical monthly bills show that all load profiles face significantly higher monthly charges in Germany than in Ontario (before any special agreements);
- In absolute value, Germany's monthly bills would be higher for all three components: electricity, delivery, and regulatory. Taxes and levies make up almost 20% of total electricity rates (after surcharge exemptions, before any special agreements);
- Customers with an annual load of 100 MWh or more are subject to "special contracts" with utilities and can negotiate special rates and exemptions. Actual prices paid by industrial customers are comparable to Ontario's industrial rates; and
- Special programs like the IRRI in Ontario could help reduce the burden for large industries, while keeping important policies in place and helping utilities with load shaving while avoiding burden shifting to other rate classes or customers.

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7.4 About LEI and its Ontario experience

LEI is a global economic, financial, and strategic advisory professional services firm specializing in energy, water, and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results. LEI has been active in Ontario since 1998.

The firm has in-depth expertise in economic and financial issues related to the electricity, gas, and water sectors, such as asset valuation, procurement, regulatory economics, and market design, assessment and analysis. The firm has its roots in advising on the initial round of privatization of electricity, gas, and water companies in the UK. Since then, LEI has advised private sector clients, market institutions, and governments on privatization, asset valuation, deregulation, tariff design, market power, strategy, and strategy development in virtually all deregulated markets worldwide, including Canada, the United States, Europe, Asia, Latin America, Africa, and the Middle East. Figure 58 provides a summary of selected LEI clients throughout the world.

LEI maintains primary offices in Toronto, Boston, and Chicago.

Figure 58. Selected LEI clients throughout the world

LEI is active across the power sector value chain and has a comprehensive understanding of the issues faced by investors, utilities and regulators alike. LEI's areas of expertise are briefly described in Figure 59, and include:

- Price forecasting and asset valuation;
- Regulatory economics, performance-based ratemaking, and market design;

- Expert testimony and litigation consulting;
- Transmission and distribution;
- Renewable energy; and
- Procurement.

Figure 59. LEI's areas of expertise

LEI has **significant experience in the Ontario market**, including previous engagements with the Independent Electricity System Operator ("IESO"), the former Ontario Power Authority ("OPA"), the OEB, Ontario Power Generation ("OPG"), Hydro One, various local electric and gas distribution companies ("LDCs"), and a number of Ontario-based independent power producers ("IPPs"), market players, and stakeholders. LEI's experience also includes testimony before the OEB on multiple occasions.

LEI performs "multi-client" forecasts for eleven regional wholesale markets across North America, including Ontario, on a semi-annual basis. These forecasts include an examination of recent market developments, key assumptions used in the modelling, and a 10-year wholesale electricity price and, where relevant, capacity price forecast. The modelling analysis - presented in the form of a 30-page report - is designed to provide clients with a concise update on trends, developments, key drivers, and price projections. It also provides a rigorous introduction to market conditions – ideal for policymakers, lenders, and investors. Each report consists of easy to understand charts, tables, and market descriptions.

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