Delivered Cost of Electricity Report

MAY 2020

Contents

1. Executive summary

The Alberta Electric System Operator's (AESO) *Delivered Cost of Electricity Report* provides an overview of the cost of electricity delivered to a range of Alberta customers, the component parts of the cost of the electricity that is provided, and the alternatives that are available to consumers. The comparative cost of self-generated or self-supplied electricity sources was analyzed, as well as the Acts and Regulations that provide the governing framework that enables customer choice in electricity delivery, including the:

- *Micro-Generation Regulation*
- *Transmission Regulation*
- *Hydro and Electric Energy Act*
- *Electric Utilities Act*

Increasingly, grid-connected customers have options to generate some or all of their electricity needs from on-site generation, thereby avoiding a portion of the costs associated with electricity distribution and transmission tariffs and the majority of the costs associated with the commodity of electricity. An examination of the major customer classes provides an overview of the costs that electricity customers may incur throughout Alberta, and the trends in costs that can incent customers to produce their own on-site power.

The analysis suggests the following high-level conclusions:

➲ Consumer costs and choices are different, due to cost structures varying by service territory and rate class.

- In Alberta, as in other jurisdictions, rural service areas that are more sparsely populated (ATCO Electric and Fortis Alberta) are more expensive to serve than urban and dense service areas (ENMAX and EPCOR). A lower number of served customers over a larger geographic area results in higher costs for distribution and transmission of electricity to consumers.
- Costs also vary by rate class, with lower-volume residential, farm, and commercial customers having higher per megawatt hour (MWh) delivered electricity costs than industrial and transmission-connected load with transmission, distribution and retail costs per MWh being higher for the smaller customers.
- The costs of the major components of the delivery of electricity to consumers and their relative proportions of the total cost have evolved.
- To maintain a reliable and congestion-free system, transmission and distribution costs have been increasing at a rate higher than inflation whereas energy costs are more volatile and fluctuate subject to multiple factors including natural gas prices, carbon policy, and evolving supply and demand fundamentals.

➲ Trends indicate that consumers in some rate classes are nearing or at a point where self-supply may be economically attractive within certain service territories.

- Recent trends of increasing wires costs combined with decreasing technology costs, i.e., solar, and lower natural gas prices make the decision to self-supply more compelling for some consumers.
- Larger commercial and industrial customers are closer to such decision points while smaller customers may reach such points further in the future. Rapidly declining costs for solar generation may make residential self-supply increasingly attractive in the near future.

Other factors beyond the cost advantage for self-supply need to be considered and likely limit a transition to self-supply.

Although the economics indicate value in moving away from grid-supplied electricity as the sole source for some customer classes, other factors may create “stickiness” to obtaining energy supply from the grid and remaining grid connected. These factors include:

- Reliability of multiple supply sources
- Capital costs of financing generation
- The presence of more attractive or “core business” investment alternatives
- Increased complexity of on-site operations
- Tariff structures including exit provisions and fixed electricity costs that may not be reduced through self-supply
- Shift in risks that are not attractive – self-supply shifts power price risks to natural gas price, project development, and operational risks
- Regulatory uncertainty of future treatment of self-supply

Several key drivers influencing the incentive and ability to self-supply are important to monitor going forward.

- **Technology costs for solar:** decreases in the cost of solar technology over the past decade have been steady and significant; the continued pace of cost decreases will increase the likelihood that residential through medium commercial customers will transition to solar and disengage from the grid
- **Grid cost increases:** future increases in distribution and transmission costs
- **Tariff treatments:** rates which incorporate a larger amount of fixed costs may render some on-site generation options uneconomic but may also increase incentive to leave grid completely
- **Regulatory treatment of self-supply:** moves to restrict benefits or ability to self-supply could reduce economic incentive
- **Carbon costs:** could impact on-site generation options; may increase relative costs for gas generation, while adding potential revenue for renewable or cogeneration options
- **Natural gas pricing:** may make self-supply options for larger commercial and industrial customers less attractive
- **Investment considerations:** attractiveness of investment alternatives, cost of capital, operational considerations

2. Overview

The AESO has been engaging with stakeholders on a number of fronts, including the integration of distributed energy resources and new technology, evolving the energy-only market, and developing a coordinated planning framework for transmission/distribution. Through the exploration of these and many other issues, the AESO is gaining a better understanding of how changes in consumer energy management may impact the economics of grid-supplied electricity.

This report reviews the historic and current delivered cost of electricity in Alberta, including variable and fixed costs. It is intended as an introductory analysis to provide industry, government, and consumers with perspective and awareness on the different costs incurred by electricity consumers across geographic service territories, and reasons for variances among service providers. It also provides insight into the potential future direction of the delivered cost of grid-supplied electricity relative to the cost of self-supply.

Albertans have choices regarding when and how they consume electricity and, increasingly, opportunities to generate their own electricity. Understanding the components of monthly electricity bills can help inform consumers about the costs and benefits of electricity supply options.

This report is structured as follows:

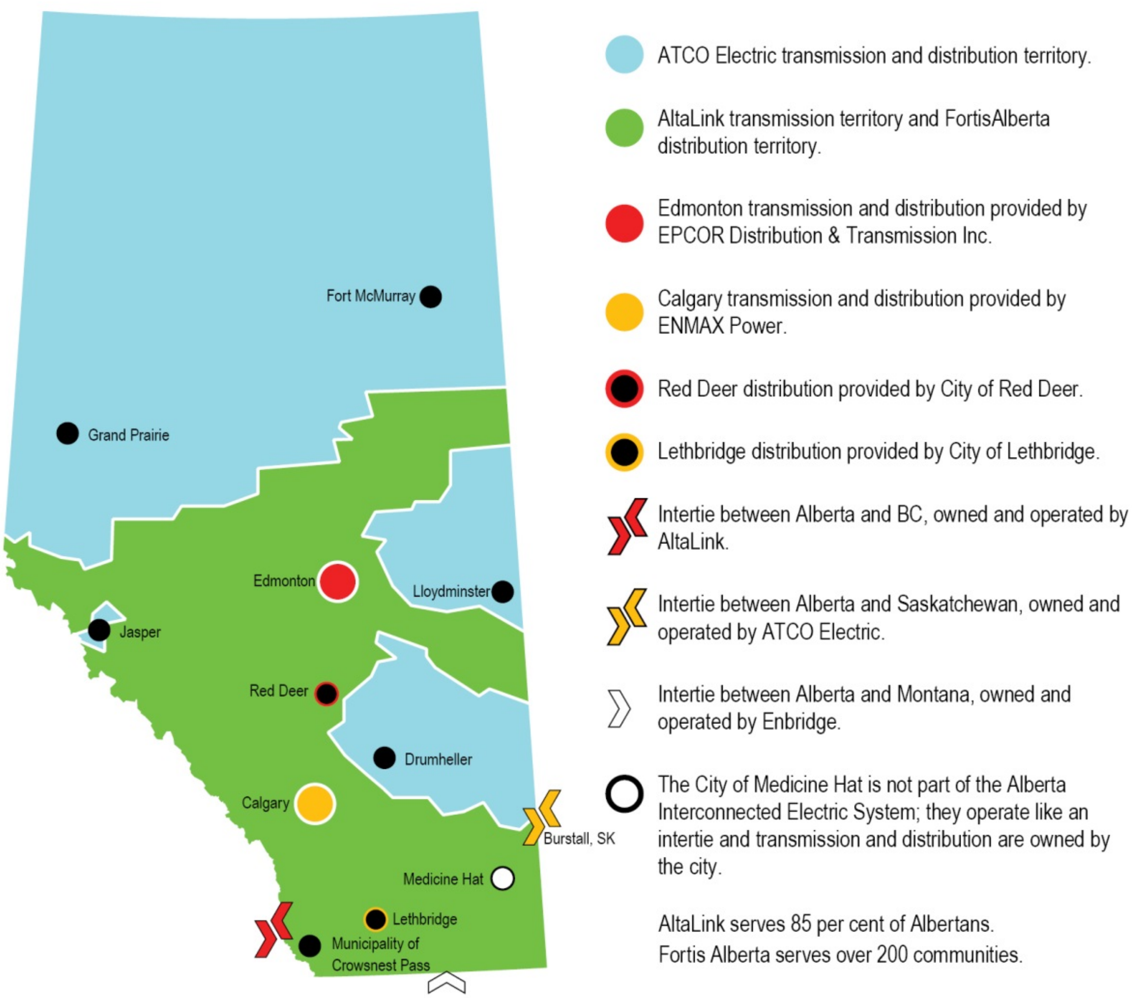
- Review of key drivers of delivered cost of electricity for major customer types
- Historic trends in the delivered cost of electricity and current state
- Options for self-supply and related considerations
- Economics of self-supply relative to current delivered costs of electricity and potential future trends
- Key factors to monitor when considering the potential of increased amounts of self-supply

3. Review of key drivers of delivered cost of electricity for major customer types

3.1 Distribution service territories

Alberta's distribution service territories consist of four major areas and a number of municipal and rural electrification entities. The four major areas include Calgary and Edmonton, operated by ENMAX Power (ENMAX) and EPCOR Distribution & Transmission Inc. (EPCOR) respectively, and two larger service territories in northern and southern Alberta, operated by ATCO Electric (ATCO) and FortisAlberta (Fortis) respectively. Each of these four service territories publishes a tariff that sets the distribution and transmission charges for various electricity customer classes in their service territories. The Alberta Utilities Commission (AUC) has the authority to approve tariffs for each distribution facility owner (DFO). The service territories applicable to the DFOs are depicted in Figure 3.1-1.

Figure 3.1-1: DFO service territories



Source: Electricity Distribution [Fact Sheet], Government of Alberta

3.1.1 Description of tariff classes

Each DFO sets the rates for various customer classes. These include:

- Residential service
- Farm service
- Commercial service
- Industrial service
- Lighting service
- Oilfield service

The customer segments are treated differently for the purposes of disseminating the system costs related to the construction and operation of the distribution and transmission systems that deliver electricity. Generally, customers with the highest volume of electricity consumption pay the lowest delivered cost of electricity on a per unit basis, i.e., $/MWh.

3.1.2 Description of cost types

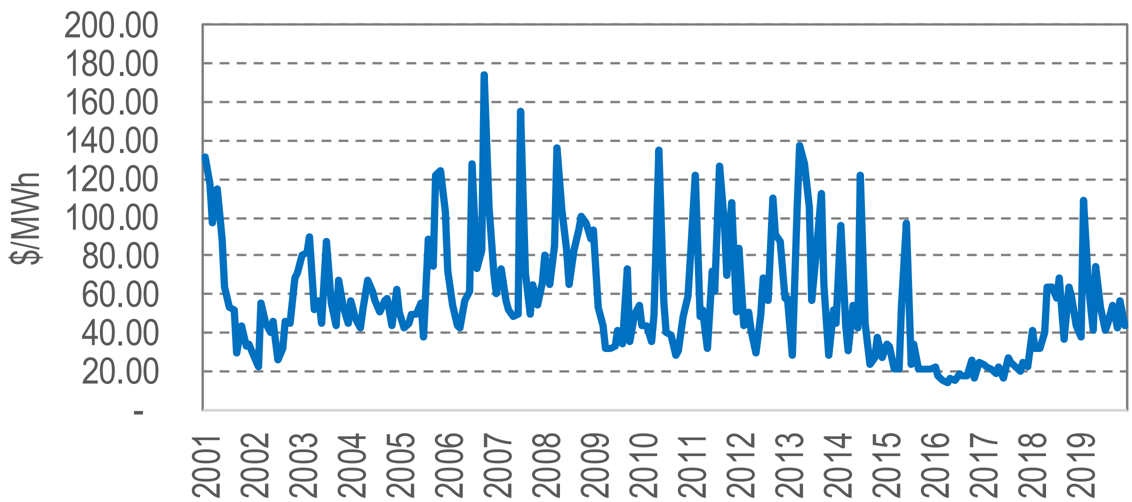
The delivered cost of electricity is comprised of:

- Commodity
- Transmission
- Distribution
- Administration
- Other expenses

Commodity costs are subject to market forces based on supply and demand interactions in the real-time energy market. These costs can be volatile and make up a substantial portion of the delivered cost of electricity. The following Figure 3.1.2-1 illustrates that monthly electricity pool prices can be volatile.

Most large customers will pay a shaped electricity price, based on the hourly pool price multiplied by their hourly consumption. As a result, customers who consume a significant portion of their electricity during on-peak periods may experience higher commodity costs than customers with a flatter load profile. The electricity commodity is a variable cost for all customer classes, but one which can be hedged to increase stability. Alberta has several retailers that compete to provide service to customers and a forward wholesale market where larger customers can transact to hedge their commodity cost.

Figure 3.1.2-1: Illustration of monthly pool price volatility



Distribution and transmission costs are less volatile than electricity commodity costs, but have tended to increase steadily over time. These delivery costs are based on a return on, and return of, capital plus operating costs, paid to the DFO and transmission facility owner (TFO) for their invested and operated infrastructure. As such, the costs tend to increase when distribution and transmission assets are replaced and when new infrastructure is constructed.

Distribution and transmission costs have increased over the past decade, as critical transmission infrastructure projects and other large transmission projects became operational. Distribution and transmission tariff costs are substantially based on variable energy use, i.e., the amount of electricity consumed, but also have fixed components for certain customer classes, i.e., connection costs that don't change with volume of consumption. Peak demand is a key determinant of several customer classes' distribution and transmission charges.

Administrative expenses are usually set by the service provider, while certain other costs, such as local access fees, are set by municipal districts. Local access fees vary widely by municipal district (MD) and are variable costs in all service territories.

The EPCOR and ENMAX service territories contain only one municipality's fee of $0.0085 per MWh and 11.11 per cent of the total distribution bill respectively. ATCO and Fortis' service territories span multiple MDs; therefore, customers in these service territories can be subject to local access fees that may vary between 0 per cent and 24 per cent, depending on the MD in which they are located. For the purposes of this analysis, a 10 per cent local access fee has been applied to ATCO and Fortis' service territories. Local access fees applicable to select municipalities are illustrated in Table 3.1-1.

Table 3.1.2-2: Municipality access fees[1]

Municipality or MD	Local Access Fee
Calgary	11.11%
Edmonton	$0.0085 / kilowatt hour (kWh)
Red Deer	13.55%
Lethbridge	15.5%
St. Albert	7.5%
Medicine Hat	$0.00546 to $0.08734 /day (fixed) plus $0.00026 to$0.00071/ kWh (variable)
Grande Prairie	11.68%
Wood Buffalo (Ft. McMurray)	0.12%

Tariff costs are in the form of: monthly fixed costs (customer connection costs regardless of load size); demand costs (based on peak consumption at the customer site); and, variable costs (based on the total consumption of electricity at the customer site during the billing period).

Depending on the applicable distribution tariff and the customer class, the combination and composition of customer billing charges may differ substantially. The methods of allocating delivery costs to customer classes within the distribution and transmission tariffs have remained relatively consistent, but the rates have changed over time.

[1] http://www.auc.ab.ca/Shared%20Documents/ENMAXPower-LocalAccessFee.pdf

http://www.auc.ab.ca/Shared%20Documents/EPCOR-LocalAccessFee.pdf

https://www.atco.com/content/dam/web/for-home/electricity/rates-and-regulatory/2020-01-01-atco-rider-a.pdf

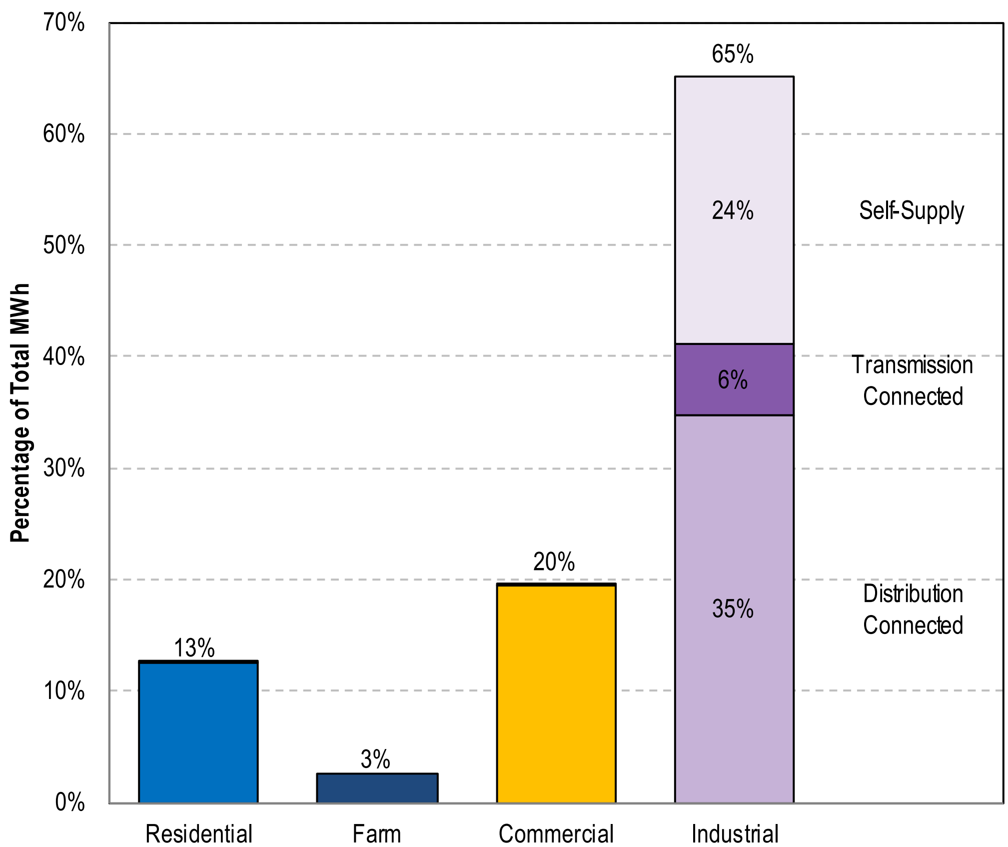
https://stalbert.ca/site/assets/files/1840/council_motion_ar-18-178_re_electrical_franchise_fee_increase.pdf

https://www.medicinehat.ca/Home/ShowDocument?id=16253

4. Representative customers & load description

This analysis relies on representative load profiles. Various customer types consume electricity at different times of the day and year, and the characteristics of their load can vary materially. On aggregate, industrial customers account for approximately 65 per cent of Alberta Internal Load (AIL), while commercial customers consume approximately 20 per cent. Residential customers make up 13 per cent of load and farm customers consume 3 per cent of AIL (refer to Figure 4.1).

Figure 4-1: AIL Profile



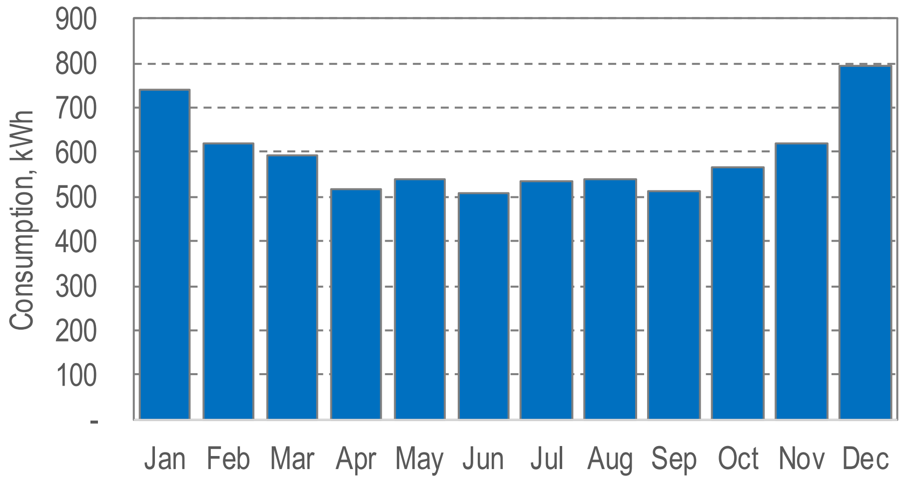
Source: AESO 2018 Annual Market Statistics Report

Approximately one quarter of the total AIL is currently industrial self-supply customers with on-site generation. These customers include petro-chemical facilities, pulp/paper and forestry processing facilities, oil sands mines, and steam assisted gravity drainage (SAGD) oil extraction facilities. In many of these applications, cogeneration of electric and thermal requirements enhances the economics of on-site generation.

In order to calculate comparable delivered cost of electricity for customer classes across the province, the AESO used representative load profiles for residential, farm, commercial, and industrial customers. These load profiles emulate the unique characteristics of different customer types, depicting the time of consumption for typical loads.

4.1 Residential customer profile

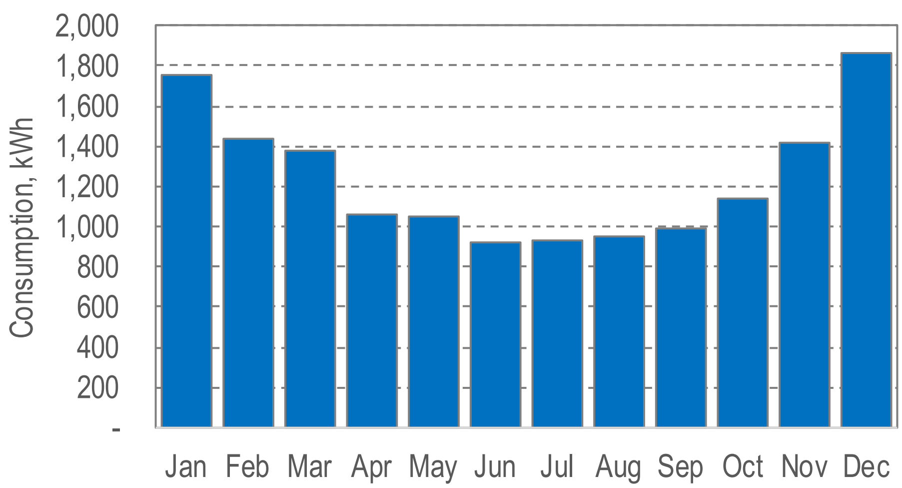
Figure 4.1-1: Monthly residential consumption profile



Residential customer profiles average under 600 kWh of monthly consumption, as illustrated in Figure 4.1-1. For the purposes of this analysis, the residential load profile incorporates a customer's load factor, seasonal and daily profiles, and average monthly consumption. The average instantaneous load is 808 watts and the peak hourly load for the residential profile is 1.73 kW. The residential profile has an average monthly load factor (average monthly load divided by peak monthly load) of 59 per cent and has a distinctive winter peak.

4.2 Farm customer profile

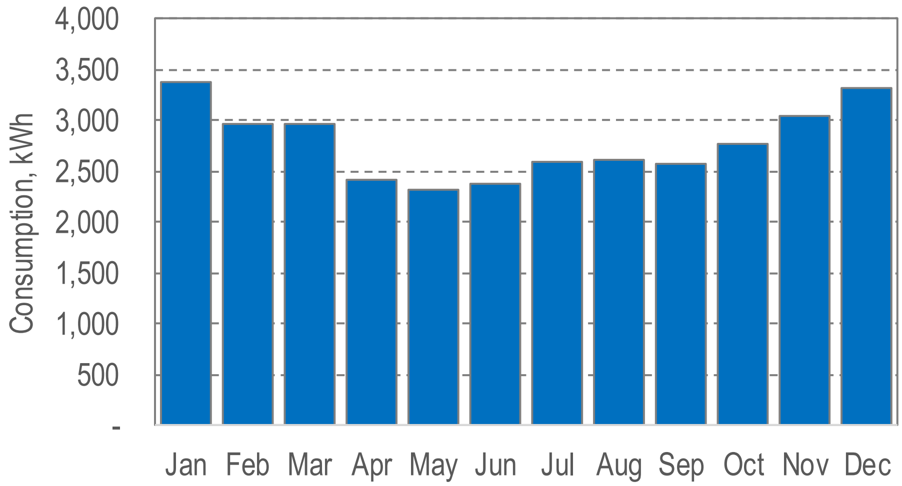
Figure 4.2-1: Monthly farm consumption profile



Farm customer profiles average 1,241 kWh of monthly consumption and have similar profiles to residential customers, as illustrated in Figure 4.2-1. The farm consumption profile peaks in the winter at 3.55 kW of hourly load and has an average load of 1.7 kW, with an average monthly load factor of 70 per cent.

4.3 Small commercial customer profile

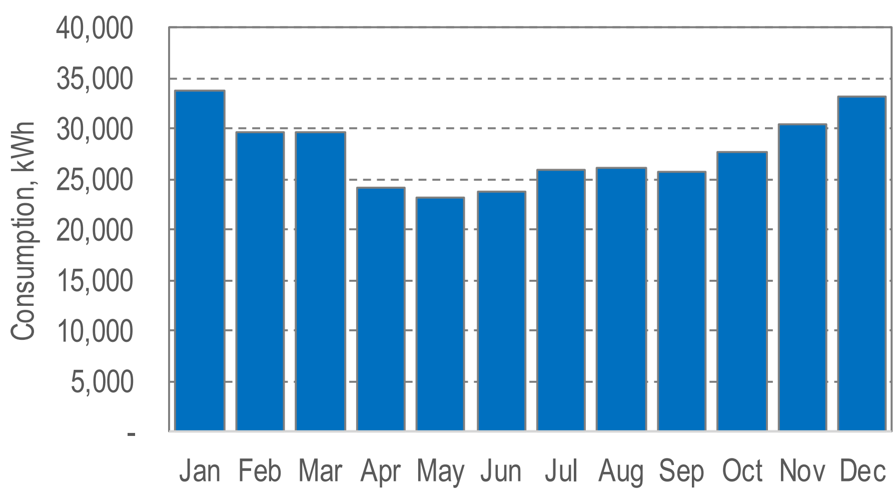
Figure 4.3-1: Monthly small commercial consumption profile



The small commercial customer profile, as illustrated in Figure 4.3-1, is also a winter peaking profile. This profile would represent many small retail stores, restaurants, and small businesses. This load profile differs from the residential load profile since it has a higher average monthly load factor of 67 per cent. The peak load for the small commercial profile is 6.27 kW, which occurs in the winter. Average load for the small commercial profile is 3.8 kW.

4.4 Medium commercial customer profile

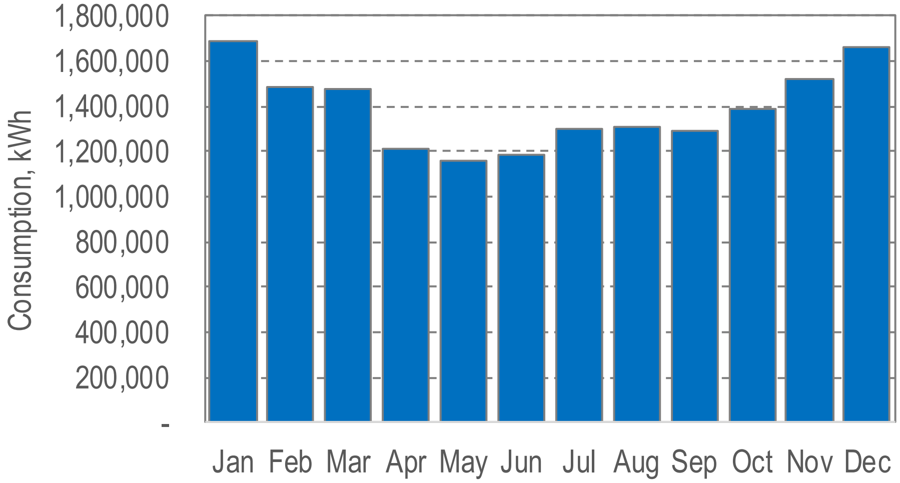
Figure 4.4-1: Medium commercial consumption profile



The medium commercial customer profile is similar in shape to the small commercial customer, as illustrated in Figure 4.4-1, but represents a larger customer. It follows the same seasonal and daily patterns and also has a 67 per cent average monthly load factor. This customer profile is 10 times larger than the small commercial customer, but similar in consumption patterns. This load profile emulates medium-sized businesses or large retail stores.

4.5 Large commercial customer profile

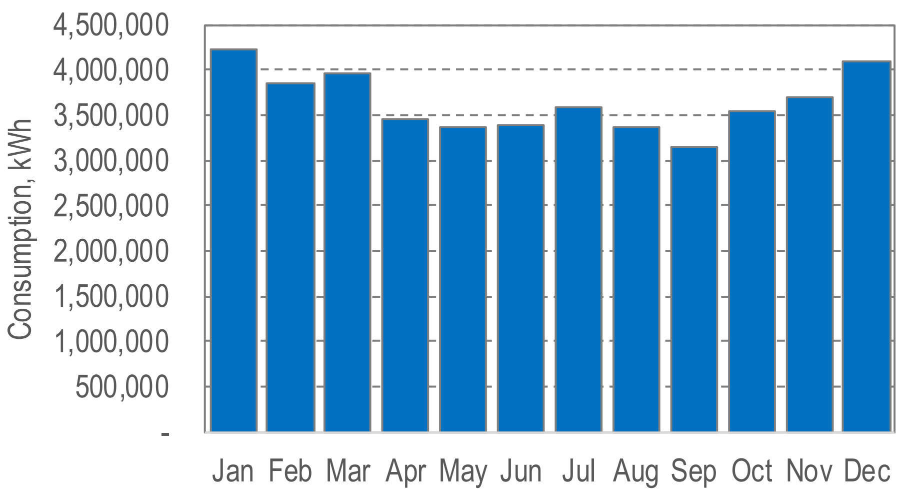
Figure 4.5-1: Monthly large commercial consumption profile



The large commercial customer profile shares the same profile as the small and medium commercial customers, but has a larger volume of consumption, as illustrated in Figure 4.5-1. This customer profile has a peak load of 3.14 MW and an average load of 1.90 MW. This customer profile represents an approximation of a large commercial office building or a large shopping centre.

4.6 Industrial customer profile

Figure 4.6-1: Monthly industrial consumption profile



The representative industrial customer profile has a higher load factor than the other profiles, as illustrated in Figure 4.6-1. This customer segment has an average monthly load factor of 82 per cent, with an average 4.97 MW of load and a peak of 6.77 MW. As with the other load profiles, the annual peak occurs in the winter months. Industrial customers are site specific, and their characteristics may vary greatly. Industrial customer connections may be to the distribution system or the transmission system, depending on the size of their load. These customers may have specific processes that determine their geographic location, e.g., forestry, refining, oil sands, etc., and related opportunities to connect to the existing system.

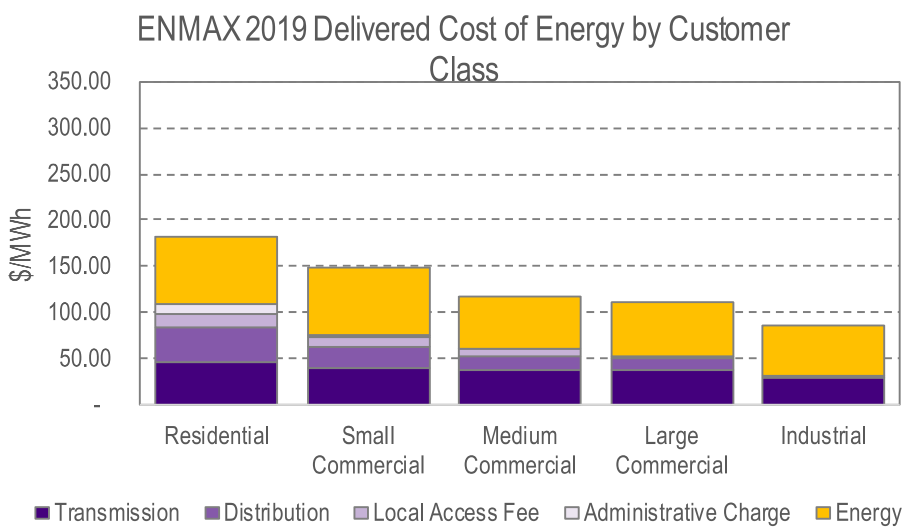
5. Delivered cost of electricity comparison

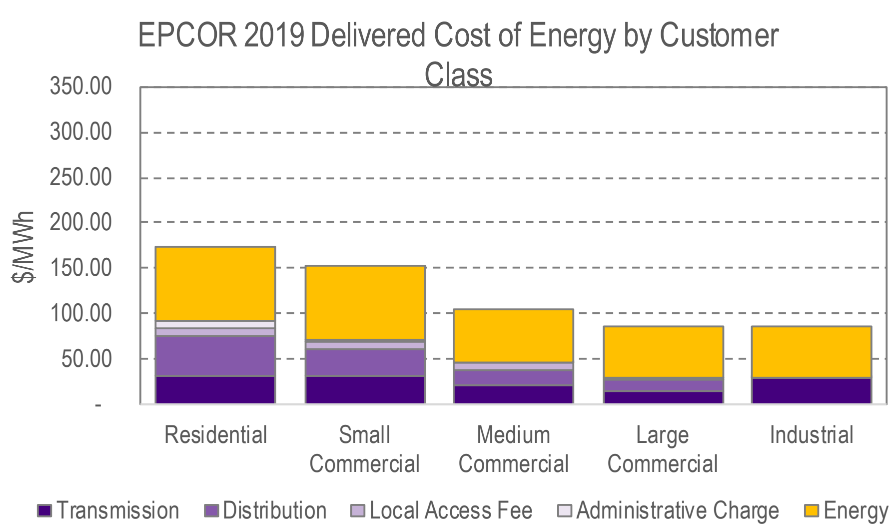
5.1 Distribution of costs

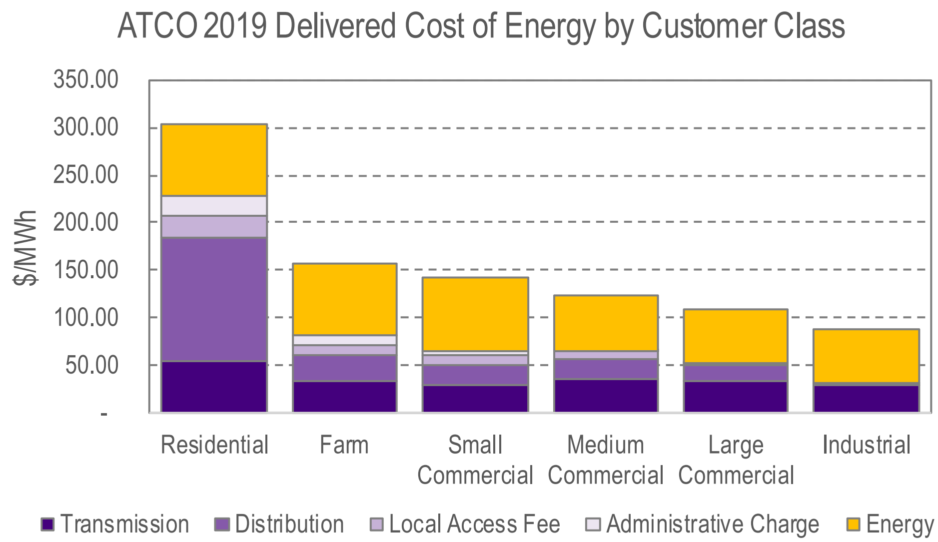
Customer electricity consumption meaningfully affects the delivered cost of electricity. Residential customers generally consume the lowest amount of electricity, while large commercial and industrial customers consume significantly higher volumes of electricity. The tariff rates consistently result in higher unit costs for smaller customers in each of the four major distribution service territories, with costs decreasing for customer classes with higher loads.

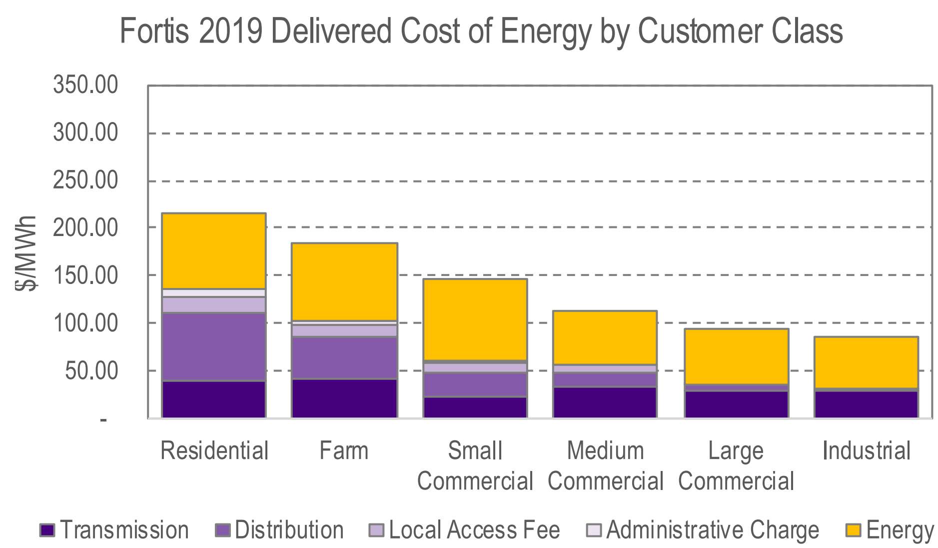
The following graphs in Figure 5.1-1 illustrate the delivered cost of electricity for various customer segments across the four major distribution territories in 2019. The consumption profiles were used to derive billing determinants based on the applicable tariff in each distribution service territory. For the purpose of this analysis, rate riders were generally excluded, except in circumstances where they were material and consistently represented a cost. ENMAX's Transmission Access Charge deferral account rider was material, and therefore was added to the transmission costs in this analysis.

Figure 5.1-1: 2019 Delivered cost of electricity by customer class across distribution territories





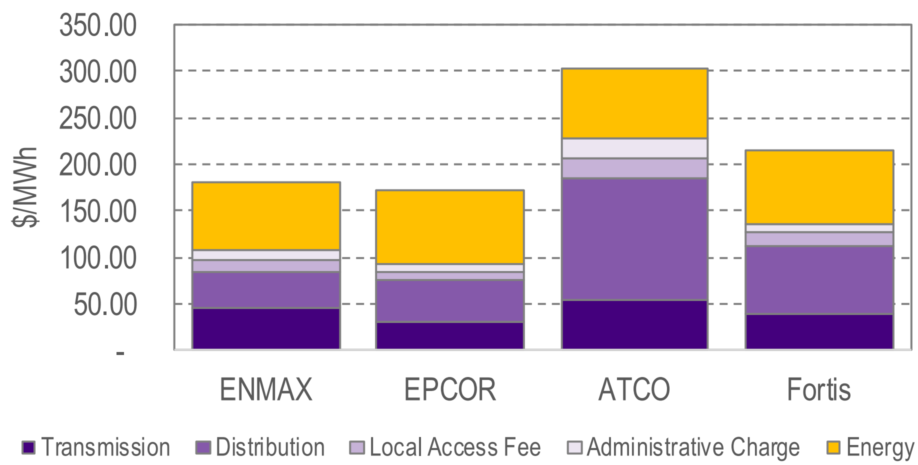

ATCO 2019 Delivered Cost of Energy by Customer Class
350.00
300.00
250.00
200.00
150.00
100.00
50.00
-
$/MWh
Residential
Farm
Small Commercial
Medium Commercial
Large Commercial
Industrial
Transmission
Distribution
Local Access Fee
Administrative Charge
Energy


Fortis 2019 Delivered Cost of Energy by Customer Class
350.00
300.00
250.00
200.00
150.00
100.00
50.00
-
$/MWh
Residential
Farm
Small Commercial
Medium Commercial
Large Commercial
Industrial
Transmission
Distribution
Local Access Fee
Administrative Charge
Energy

6. Estimated per unit delivered electricity cost by customer class and distribution service territory

6.1 Residential

Figure 6.1-1: 2019 Residential – delivered cost of electricity across service territories



The delivered cost of electricity for residential customers primarily consists of:

- Transmission charges
- Distribution charges
- Energy charges
- Local access fees
- Administrative charges

For the purpose of this analysis, the Regulated Rate Option (RRO)[2] price was used to illustrate the energy component of the total delivered cost of electricity. On a month-to-month basis, energy prices can fluctuate meaningfully for residential and RRO customers. In addition, customers can lock into a fixed rate for various durations by selecting options offered by a competitive retailer. The more consistent components of the delivered cost of electricity relate to distribution and transmission of electricity. Local access fees represent franchise fees charged by municipal districts to customers in the service area, as compensation or rent on the utility rights of way used to deliver electricity. Administrative charges represent a cost associated with billing and administration of customer accounts by electricity retailers.

[2] The RRO rate is determined from market electricity prices using a process approved by the AUC and is meant to fairly compensate energy providers, while also ensuring that customers pay a fair and reasonable price.

The delivered cost of electricity varies between service territories. Electricity commodity costs have been estimated based on the applicable RRO rate in each service territory for the purposes of this analysis. The variation in delivered cost of electricity can be primarily attributed to the different costs associated with distribution and transmission in each service territory, since the single-price energy market provides a similar energy cost across service territories.

The urban service territories, ENMAX and EPCOR, have lower combined delivery costs (distribution and transmission) than the rural service territories operated by ATCO and Fortis. ATCO's distribution costs for a typical residential customer are higher than the same customer would experience in other service territories. This is the result of the relatively long distances between customers, the relatively small number of customers in the service territory, and complexities of the terrain in northern Alberta.

The delivered cost of residential electricity has increased over time, primarily due to increased distribution and transmission costs. Over the past decade, residential customers throughout Alberta have experienced steady and significant increases in the distribution and transmission components of their electricity bill.

Figure 6.1-1: Residential – delivered cost of electricity over time across service territories

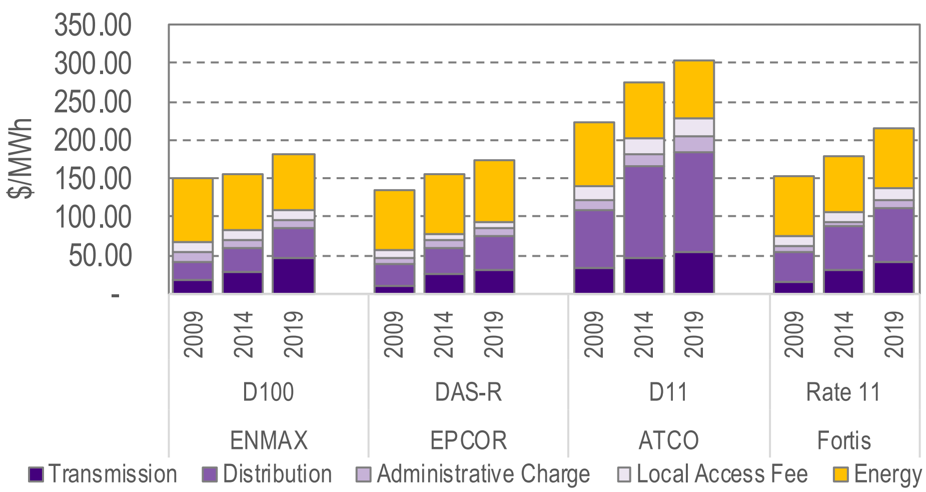
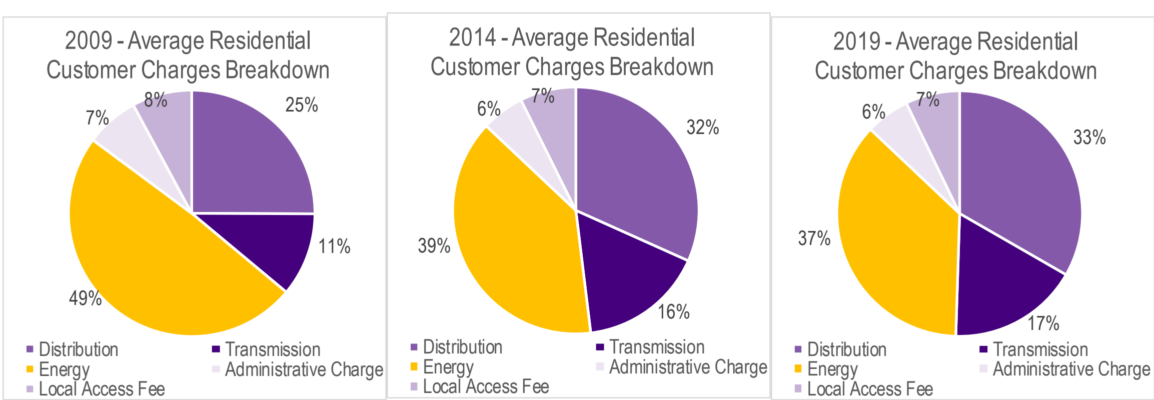


Figure 6.1-2: Average residential customer charges breakdown over time

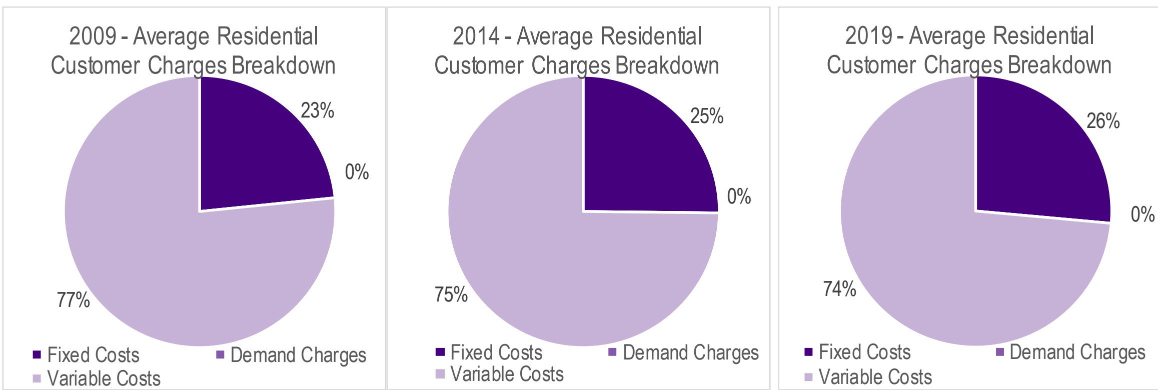


The AESO reviewed each DFO tariff to break down the delivered cost of electricity into fixed, demand, and variable expenses.

- Fixed costs: incurred by customers irrespective of the monthly consumption at their site
- Demand charges: based on the highest periodic demand (peak consumption) during the billing period
- Variable costs: based on the total consumption of electricity at a customer site during the billing period

Residential customers do not have a demand charge included in their tariff, unlike other customer classes. Most residential sites are metered with cumulative meters, which inhibit metering of instantaneous loads.

Figure 6.1-3: Average residential customer charges breakdown over time



6.2 Farm

Farm customers represent a customer class in ATCO and Fortis service territories. Their delivered cost of electricity is comprised of lower distribution and transmission costs than residential customers. However, a higher portion of the typical farm electricity bill is based on maximum capacity of monthly consumption (peak demand), compared to other customers. The electricity commodity costs for farm customers were also based on the RRO applicable to each service territory.

Figure 6.2-1: 2019 Farm – delivered cost of electricity across service territories

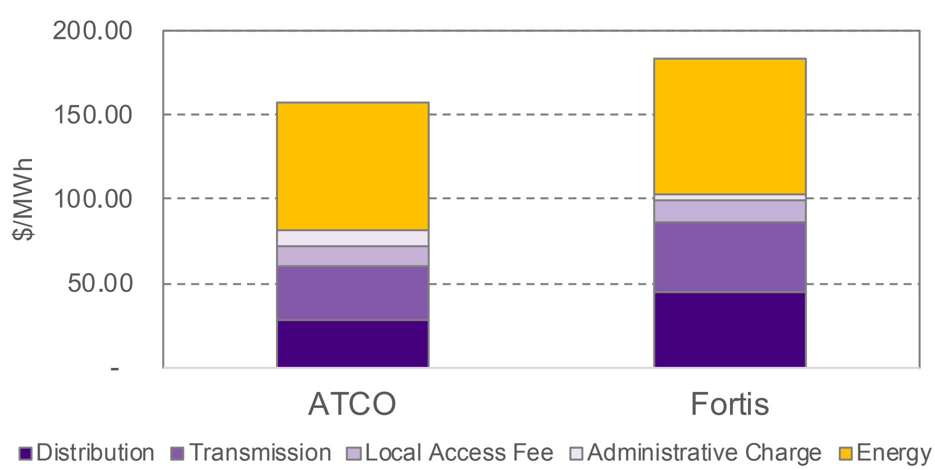


Figure 6.2-2: Farm – delivered cost of electricity over time

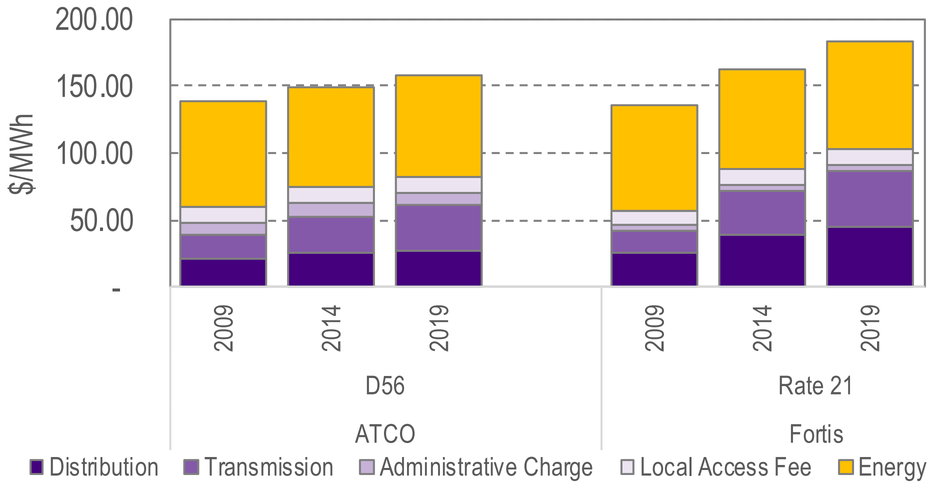
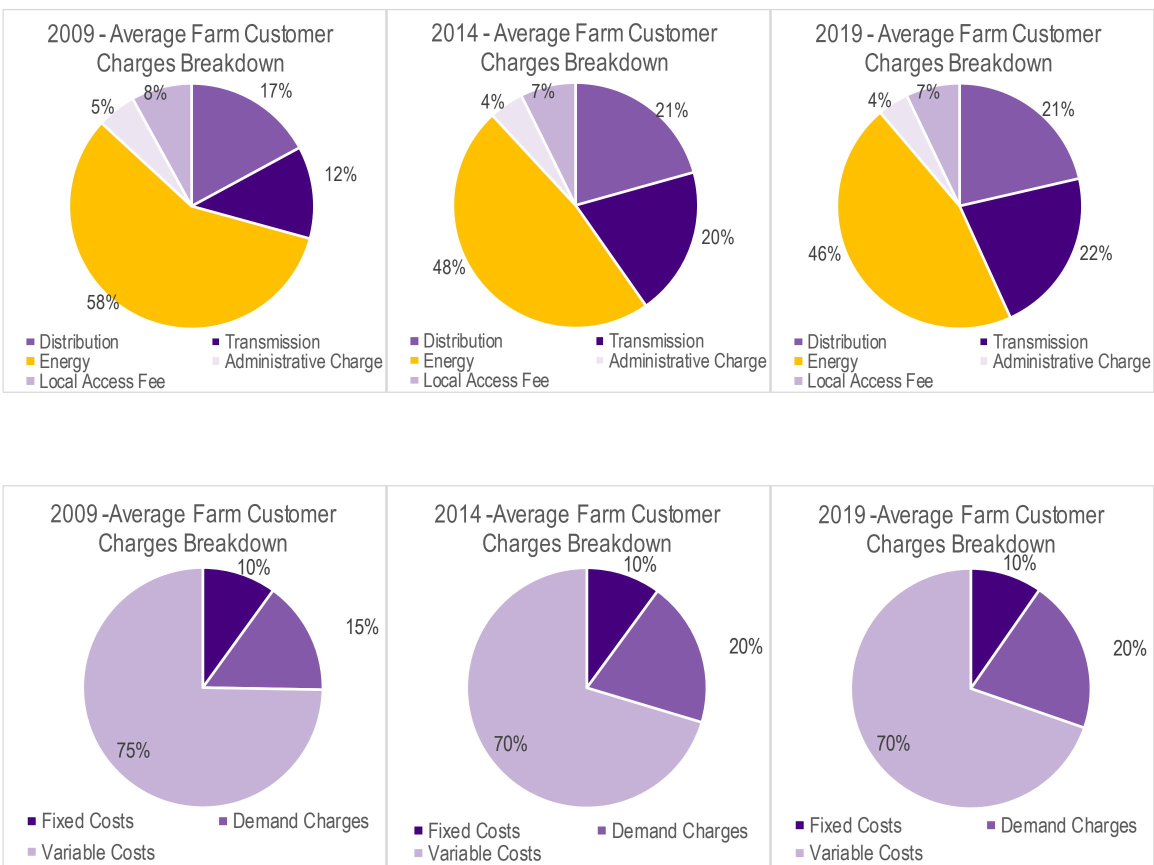


Figure 6.2-3: Average farm customer charges breakdown over time



As with other rate classes, the delivered cost of electricity to farm customers has increased over the past decade. This increase is the result of higher distribution and transmission costs.

6.3 Commercial

6.3.1 Small commercial

Figure 6.3-1: 2019 Small commercial – delivered cost of electricity across service territories

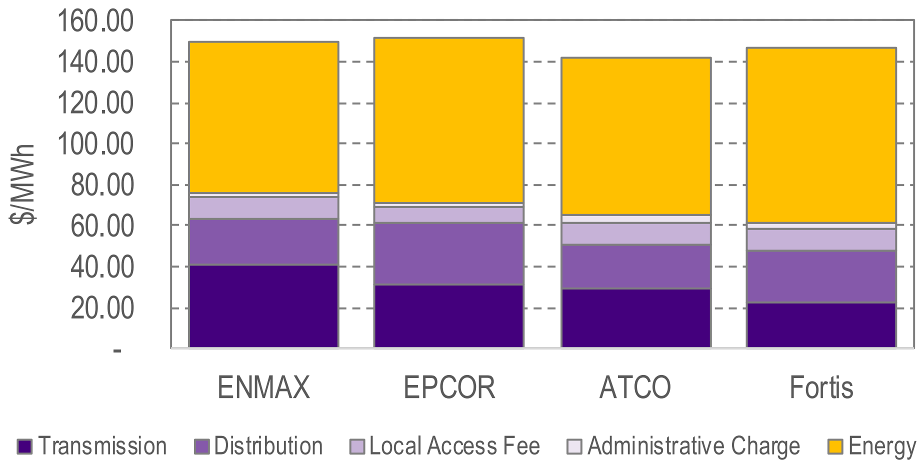


Figure 6.3-2: Small commercial – delivered cost of electricity over time, across service territories

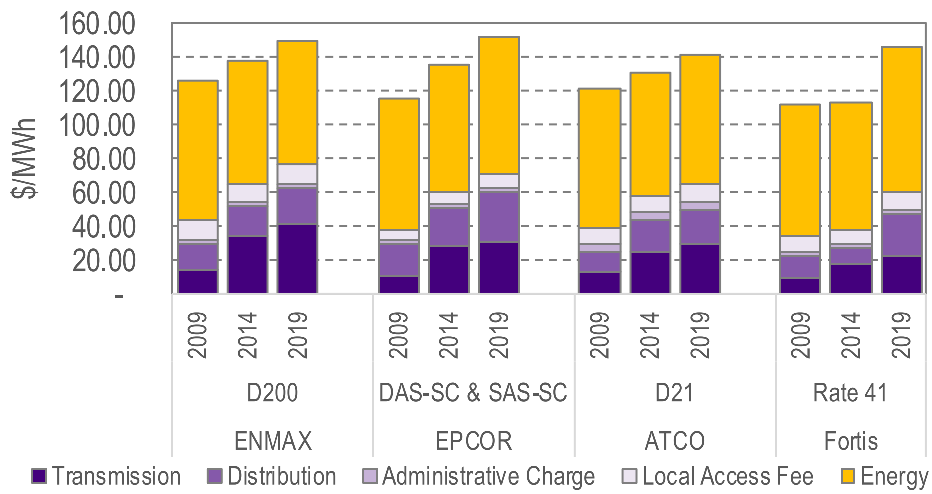
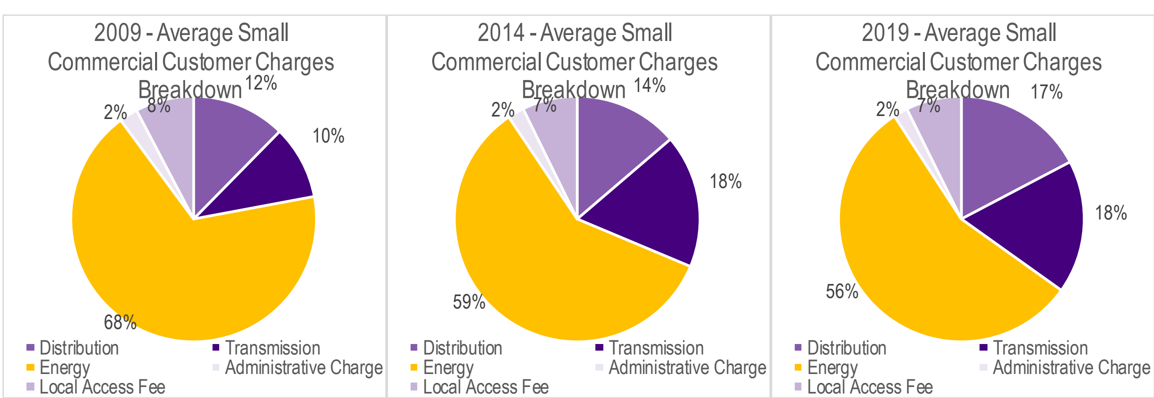
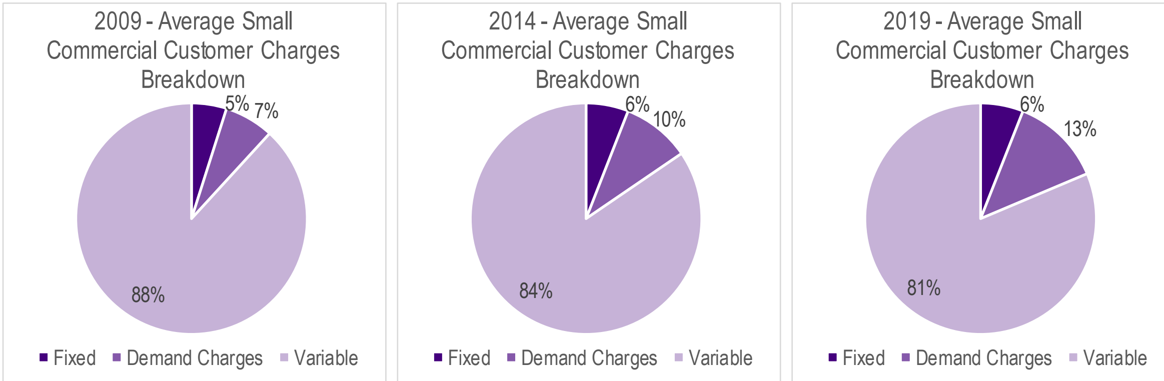


Figure 6.3-3: Average small commercial customer charges breakdown over time





6.3.2 *Medium commercial*

Figure 6.3.2-1: 2019 Medium commercial – delivered cost of electricity across service territories

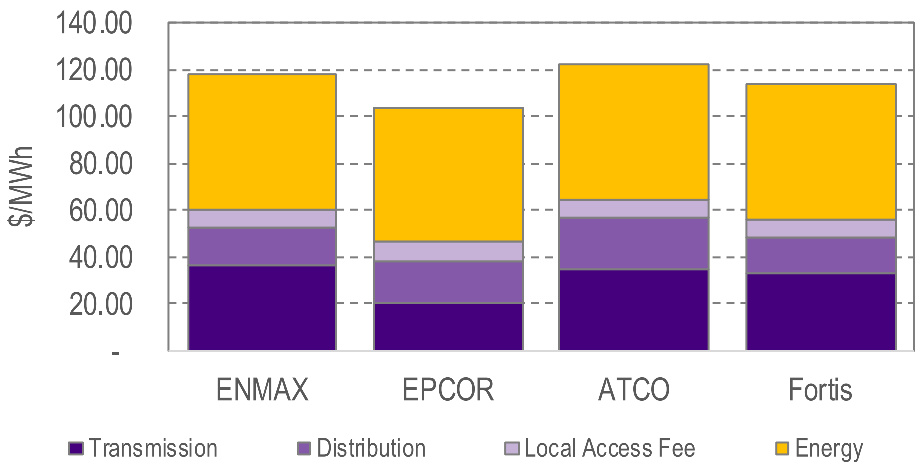


Figure 6.3.2-2: Medium commercial – delivered cost of electricity over time, across service territories

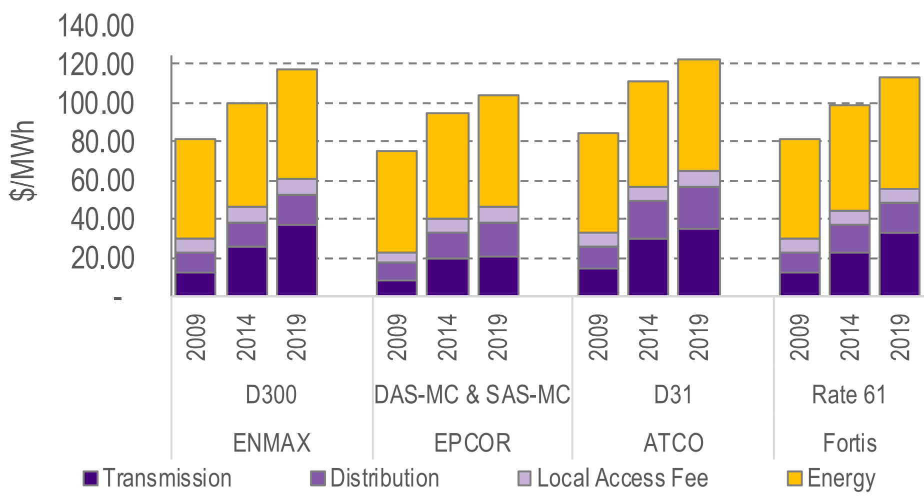
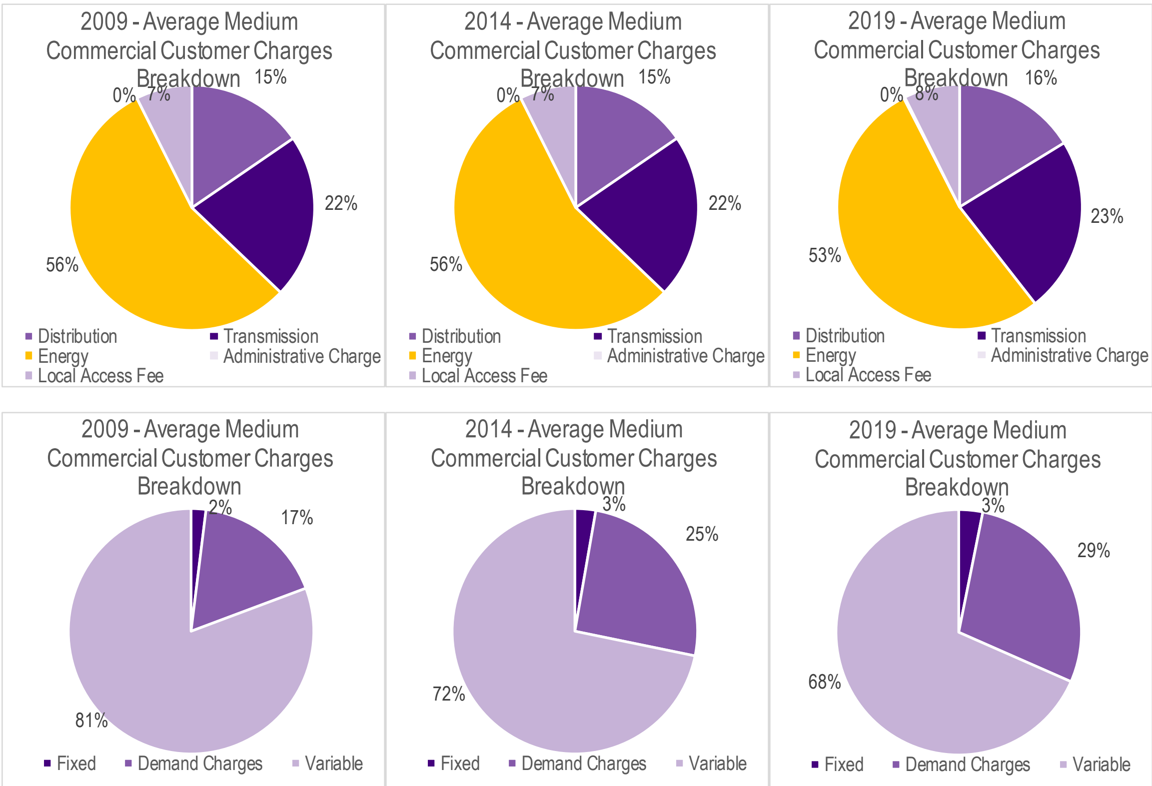
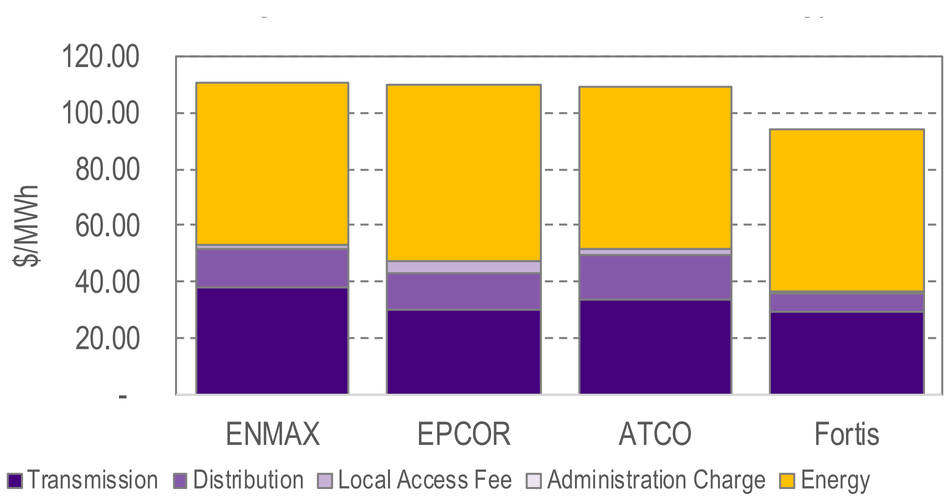


Figure 6.3-3: Average medium commercial customer charges breakdown over time

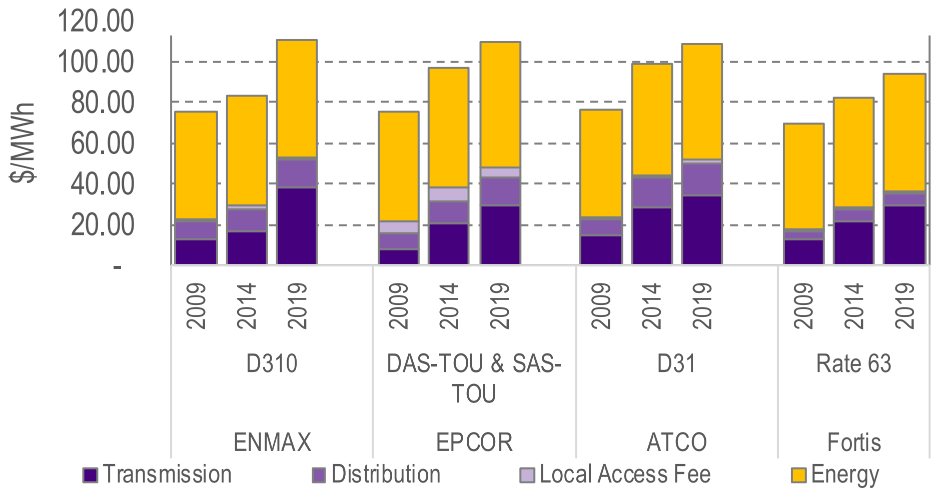


6.3.3 *Large commercial*

Figure 6.3.3-1: 2019 Large commercial – delivered cost of electricity across service territories

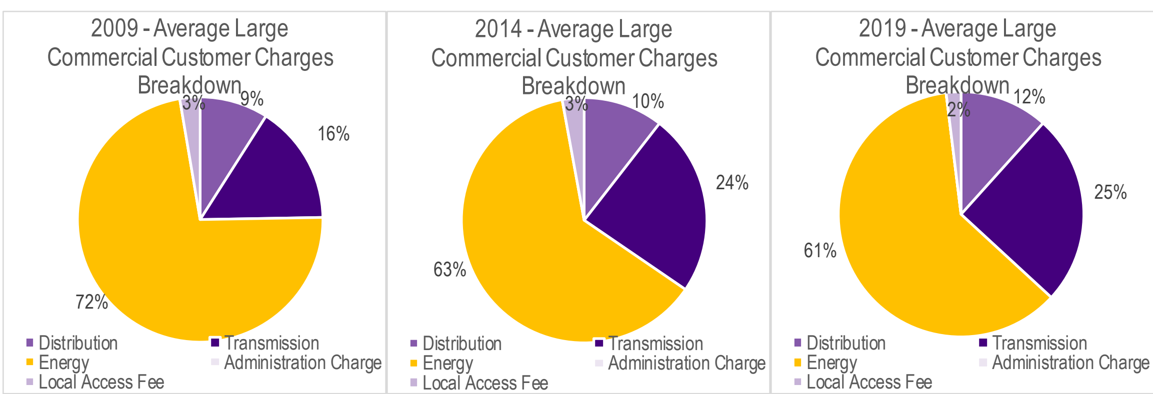


6.3.3-2: 2019 Large commercial – delivered cost of electricity over time

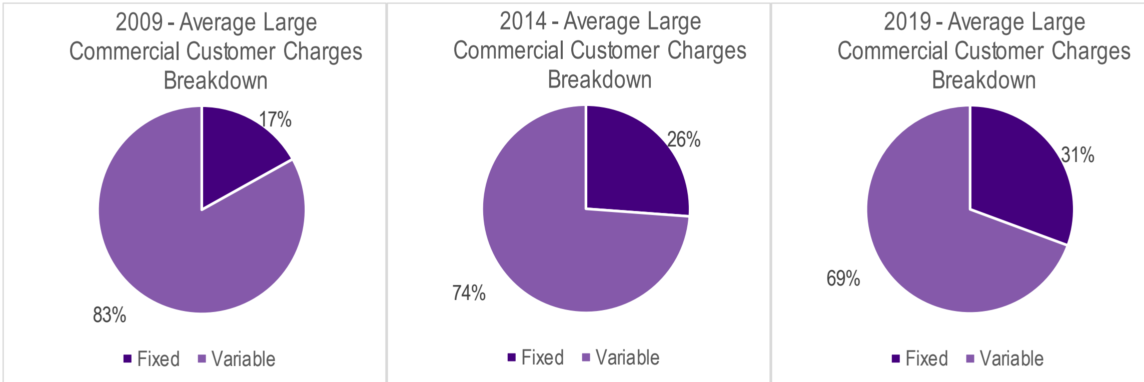


The commercial customer class varies greatly in electricity use, peak demand, and load factor. ENMAX, EPCOR, and Fortis have three customer classes that represent commercial loads, while ATCO has two[3]. The delivered cost of electricity for commercial customers is weighted to energy costs, although distribution and transmission costs have represented an increasingly large component for these customers over the past decade. Small commercial customers pay higher transmission expenses than their medium and large commercial counterparts. In this analysis the small commercial customer commodity costs were based on the applicable RRO for the service territory, while medium and large customers were analyzed based on the hourly pool price multiplied by their hourly consumption profile.

6.3.3-3: Average large commercial – customer charges breakdown over time

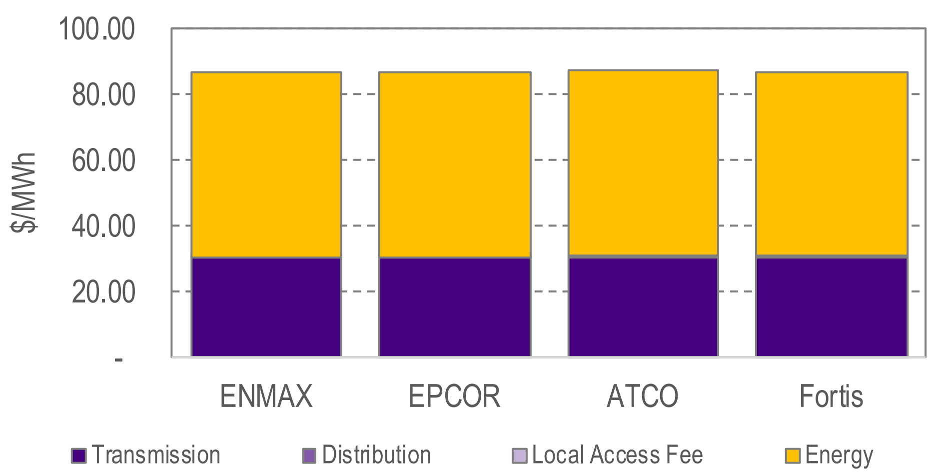


[3] ENMAX's D200, D300, and D310 rates represent different sizes and connections of commercial load. EPCOR's DAS-SC, DAS-MC, and DAS-TOU rates may apply to commercial loads. ATCO's D21 and D31 general service rates apply to commercial loads in their service territory, and Fortis' Rate 41, Rate 61, and Rate 63 apply to commercial loads in their service territory. Larger commercial loads could apply to alternative rate classes as well.

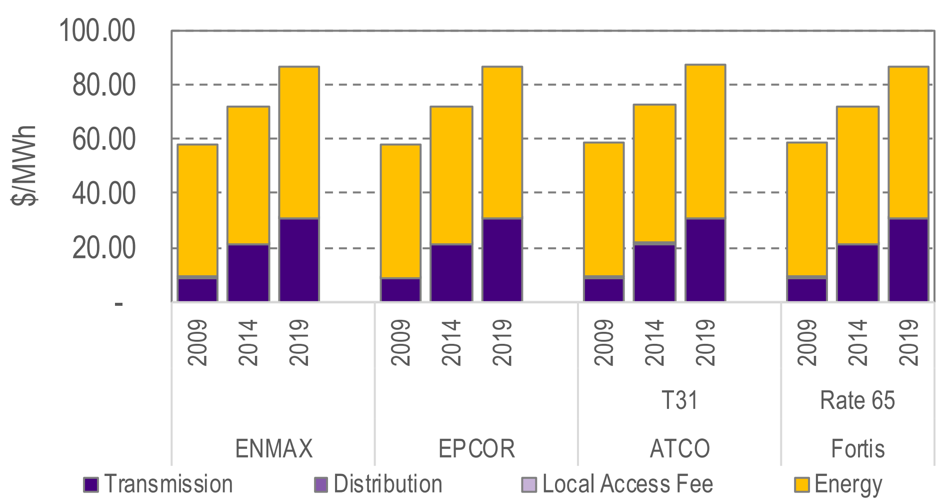


6.4 Industrial

6.4-1: 2019 Industrial – delivered cost of electricity across service territories



6.4-3: Industrial – delivered cost of electricity over time, across service territories



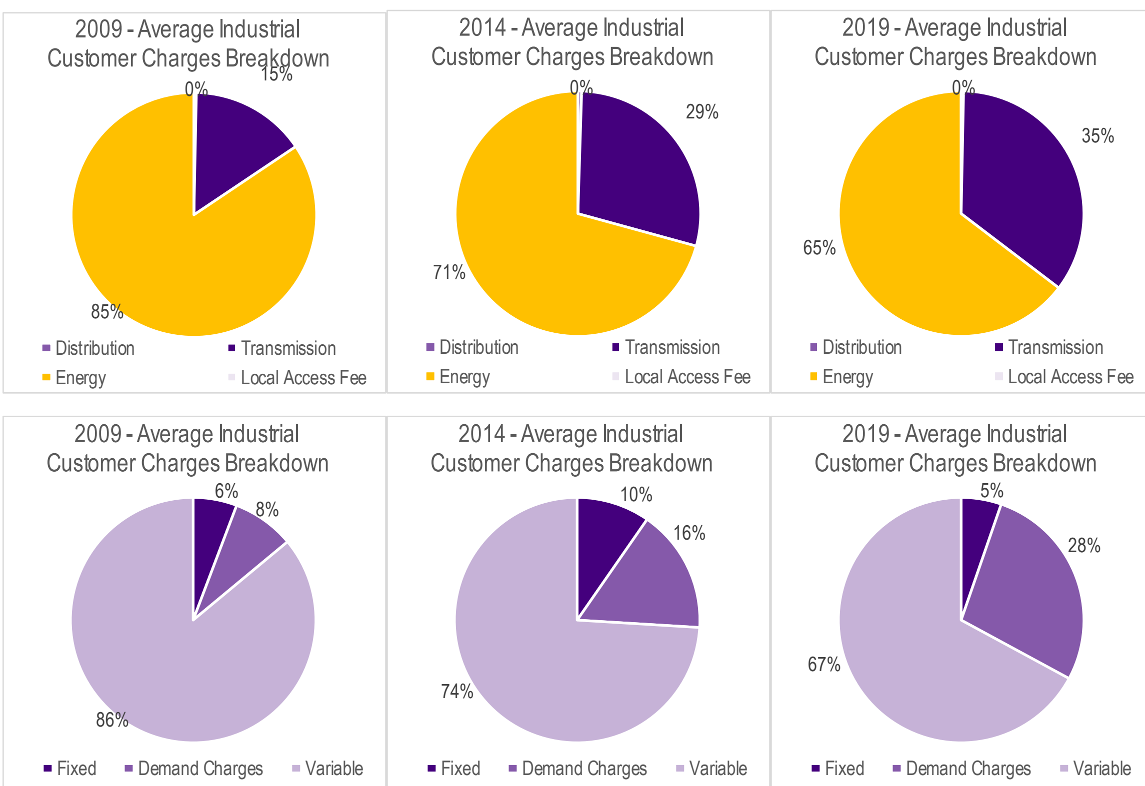
An industrial customer could be distribution-connected or transmission-connected, which will impact its tariff treatment and delivered cost of electricity. The industrial transmission-connected customer, previously illustrated in Figure 6.4-3, pays a modest fee to the distribution utility, and pays the transmission system tariff set by the AESO.

- A distribution-connected industrial customer would fall under the same tariff as a large commercial customer in ENMAX (D410), Fortis (Rate 63), and ATCO's (D31) service territories
- A distribution-connected customer in EPCOR's service territory:
  - could fall into the large commercial class (SAS-TOUP, if the load is 150kVA to <5000kVA)
  - or into a distribution-connected commercial/industrial class (SAS-CS, if the load is >=5,000 kVA), which has rates similar to a transmission-connected customer (SAS-DC)

Industrial transmission-connected customers experience the lowest delivered cost of electricity among the major rate classes. These customers tend to consume the largest volumes of electricity and often have higher load factors than other customers. Industrial processes can vary greatly between customers, and these consumers are often the most active load participants in Alberta's electricity market, since electricity may represent a primary input cost to their production.

The industrial transmission-connected tariff costs have increased materially between 2009 and 2019, as several major transmission projects were commissioned within this timeframe. The delivery costs have tripled for industrial customers in the past 10 years, compounding at an annualized rate of approximately 24 per cent, and representing over one-third of the industrial customer delivered cost of electricity. Demand charges have also increased meaningfully for industrial customers in Alberta over the past decade.

6.4-4: Average industrial customer charges breakdown over time



7. Annualized growth rates of delivered electricity costs

Total delivered electricity costs have, with limited exceptions, increased at an annualized rate greater than general inflation over the past decade. Key components of the delivered cost have experienced even greater cost growth.

Over the past decade, the distribution & transmission costs for all classes of customers have increased:

- Residential customers have experienced annual delivery cost increases between 7 per cent and 11 per cent
- Commercial customers have experienced annual delivery cost increases between 10 per cent and 18.3 per cent
- Industrial customer delivery costs have increased at an annual rate of approximately 24 per cent

Although distribution & transmission costs represent only one element of the delivered cost of electricity, this proportion has increased materially over the past decade.

Delivered cost of electricity: annualized rate of increase (2009 to 2019)				
Customer class	**ENMAX**	**EPCOR**	**ATCO**	**Fortis**
Residential	2.1%	3.0%	3.7%	4.1%
Farm	N/A	N/A	1.4%	3.5%
Small commercial	1.8%	3.1%	1.7%	3.0%
Medium commercial	4.4%	3.9%	4.5%	3.9%
Large commercial	4.7%	4.6%	4.3%	3.4%
Industrial	4.9%	4.9%	4.9%	4.9%

Distribution costs: annualized rate of increase (2009 to 2019)				
Customer class	**ENMAX**	**EPCOR**	**ATCO**	**Fortis**
Residential	5.6%	6.6%	7.2%	8.7%
Farm	N/A	N/A	3.5%	7.1%
Small commercial	5.0%	5.7%	7.7%	9.4%
Medium commercial	4.8%	10.2%	8.9%	3.8%
Large commercial	4.9%	8.6%	8.5%	5.2%
Industrial	5.3%	12.7%	2.7%	6.9%

Transmission costs: annualized rate of increase (2009 to 2019)				
Customer class	**ENMAX**	**EPCOR**	**ATCO**	**Fortis**
Residential	18.0%	18.8%	6.7%	16.8%
Farm	N/A	N/A	8.5%	16.4%
Small commercial	17.5%	17.7%	12.2%	13.0%
Medium commercial	20.3%	14.2%	13.8%	17.6%
Large Commercial	19.4%	27.1%	13.6%	12.6%
Industrial	24.2%	24.2%	24.2%	24.2%

Electricity Costs: Annualized Rate of Increase (2009 to 2019)				
Customer Class	**ENMAX**	**EPCOR**	**ATCO**	**Fortis**
Residential	-1.2%	0.4%	-0.8%	0.2%
Farm	N/A	N/A	-0.5%	0.1%
Small commercial	-1.2%	0.4%	-0.6%	1.0%
Medium commercial	1.0%	1.0%	1.0%	1.0%
Large commercial	1.0%	1.5%	1.0%	1.0%
Industrial	1.4%	1.4%	1.4%	1.4%

Note: The commodity portion of the delivered cost of electricity did experience volatility between 2009 and 2019. Annual average electricity prices settled between a low of $18.28 per MWh in 2016 and high of $80.19 per MWh in 2013.

8. Self-supply options

Customers have several options to reduce their electricity costs:

- Find ways to reduce consumption, thereby reducing variable costs and possibly influencing peak demand charges
- Consider augmenting grid connection with a generation source, such as a solar panel or a natural gas generator
- Install sufficient control systems and generation to disconnect from the electrical system altogether; however, this would be an extreme case, as grid disengagement could sacrifice the reliability of the islanded electrical system or entail higher costs

When a customer elects to install supply at their site, they are able to offset some (or all) of their commodity costs and a significant portion of transmission, distribution, and other costs; however, they will incur generator-associated operating costs. Generally, the variable costs can be reduced substantially because metered volumes are reduced, and fixed costs that are based on peak load may be reduced depending on the resulting net load profile, subsequent to the installation of on-site generation.

The *Micro-generation Regulation* streamlines the installation and operation of distribution-connected generators (5 MW or less) in Alberta, by explicitly defining requirements of a generator and the DFO. The capital costs associated with the installation and operation of the generator are borne by the customer, but the DFO must enable the installation and operation of the micro-generation. Effectively, the *Micro-generation Regulation* streamlines the process of installing a generator at a customer site, and also sets out the payment and credit options and mechanisms that a micro-generator can receive for the on-site generation.

On-site generation provides an opportunity for electricity consumers to supply a portion of their own electrical needs. There are several different forms of on-site generation including:

- Solar
- Wind
- Hydro
- Geothermal
- Cogeneration
- Fossil-fuel fired

In Alberta, a large proportion of small-scale consumers can install:

- Solar photovoltaic (PV) systems
- Natural gas generators (to enable on-site power generation)

Only a small subset of niche customers would be able to install options including:

- Wind
- Hydroelectric
- Geothermal
- Cogeneration

Complete grid disengagement would require an islanded system, with the following considerations:

- Incorporation of control systems, redundant generation, and operation systems
- More expensive and burdensome to manage than an integrated on-site generation system
- Small isolated grids may experience lower power quality and less flexibility of dispatch than a larger integrated electrical system

For these reasons, islanded systems have not historically been considered as viable alternatives for most Alberta consumers.

Large industrial customers may have scope for complete grid disengagement, but this has not been evidenced to date as an emerging trend. However, the size of a customer load, geographic location, and isolation are more likely to drive an islanded system than economically elected isolation.

The following table provides an overview of on-site generation options. It compares the key considerations of various self-supply options across customer classes, and indicates the most relevant technologies for typical on-site generation in each customer class.

<table>
<tr><th>Customer class:
Self-supply options</th><th>Residential</th><th>Farm</th><th>Small commercial</th><th>Medium commercial</th><th>Large commercial</th><th>Industrial</th></tr>
<tr><td>Solar PV</td><td colspan="4">- benign electricity source
- easily integrated into many buildings' existing footprint
- low maintenance burden</td><td colspan="2">- area available for PV arrays is likely insufficient to offset load</td></tr>
<tr><td>Battery</td><td colspan="4">- uneconomic in most arbitrage and storage applications
- could be used as part of an "off-grid system"</td><td colspan="2">- possible niche applications, but not generally useful for self-supply</td></tr>
<tr><td>Wind turbine</td><td>- too tall for urban environment</td><td>- plausible, but site specific
- may not cover a significant portion of load</td><td colspan="3">- too tall for urban environment</td><td>- plausible, but site specific
- may not cover a significant portion of load</td></tr>
<tr><td>Natural gas generation</td><td colspan="4">- limited economic generation options
- noise and emissions concerns
- complex operation of systems
- small cogeneration units may have site-specific opportunities, but current adoption rates are low</td><td colspan="2">- economic size
- efficiency aligns with Micro-generation Regulation definition of "renewable or alternative energy"
- simple cycle and cogeneration options</td></tr>
</table>

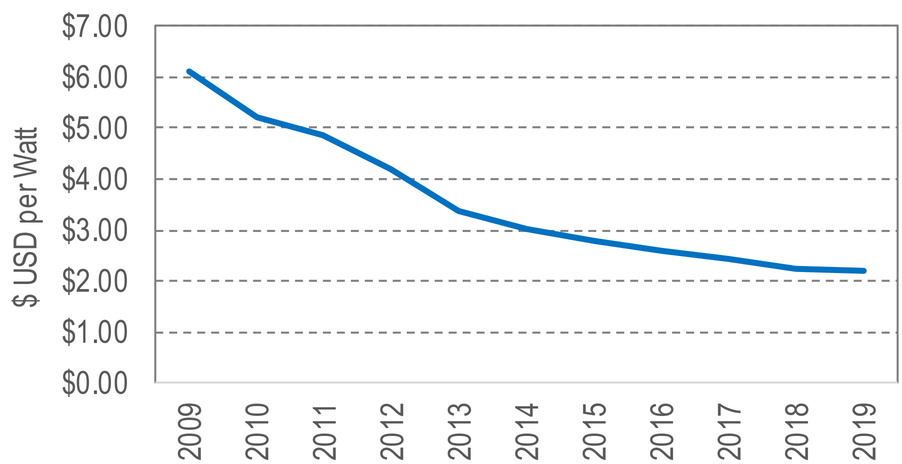
8.1 Solar photovoltaic generation

Solar PV generation currently represents the most common self-supply option for smaller customer classes. Residential, farm, small-commercial and medium-commercial customers may install solar PV panels on their site to cover a substantial portion of their electricity needs. When a customer installs solar generation at a large enough size, they can generate surplus electricity in the solar-intensive summer months, which provides revenue to offset commodity consumption in future periods.

Solar PV systems are relatively benign, i.e., they have no moving parts and can be integrated on top of existing structures. Small solar systems do not require significant maintenance. Other small generation options tend to have greater externalities for urban customers, such as noise, emissions, or tall towers, which render them prohibitive to small customer classes. As such, solar PV is a logical self-supply choice for residential, farm, and commercial electricity customers who may have limited operational experience with power systems.

The cost of roof-mounted solar PV generation has decreased significantly in the past decade. IHS Markit estimates that the cost has declined from $6.11 USD ($7.03 CAD) per watt of installed capacity in 2009 to $3.03 USD ($3.34 CAD) per watt in 2014 and $2.13 USD ($2.83 CAD) per watt in 2019[4].

Figure 8.1-1: Solar PV capital costs



Analysis assumptions

- Operating costs for a fixed-array rooftop mounted solar PV system are very low, considered negligible
- The estimated cost of electricity supplied by a small-scale solar PV system is calculated as the fixed cost divided by the estimated production
- Three levels of required return on capital (0%, 5%, and 10 per cent) in addition to the required return of capital for the solar PV system, resulting in a 2019 delivered cost range between $140 and $365 per MWh, depending on the customer class[5]
  - These discount rates were selected to represent different incentives that customers may face when making a decision to self-supply
  - A zero per cent return represents a customer who is assumed to be seeking to cover the cost of the capital equipment over its useful life (such a customer is likely motivated by social objectives such as sustainability)
  - A 10 per cent return represents the expectation of a financially motivated investor who is switching to self-supply as an investment in capital, which can reduce their ongoing electricity costs
- Solar generation is strongest in Alberta in the summer months, when the sun is overhead for longer periods than the winter months, when the sun is low on the horizon for shorter intervals
- The production profile for each solar system was estimated using the National Renewable Energy Laboratory's PVWatts model[6]
- For residential, farm and commercial customers, the estimated capacity factor of a solar PV module is around 14 per cent, and relies on a south-facing exposure with a tilt of 20 degrees

[4] Source: IHS Markit. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without written permission by IHS Markit.

[5] Fixed, demand, and variable tariff components for different customer classes impact the delivered cost of electricity, in addition to the capital and operating costs of onsite generation equipment

[6] Available at https://pvwatts.nrel.gov/pvwatts.php

Understandably, not all the customer locations will have unobstructed access to such an ideal solar site. Since the capital costs will be sunk upon installation, a customer will effectively convert a large portion of their variable electricity commodity costs into fixed capital expenses. As such, a customer could incur higher unit electricity costs if the solar PV system does not generate optimally. Further, some customers may not have sufficient surface area to accommodate the ideally sized PV array. These factors are an important consideration in determining the value realized by a customer with on-site solar generation.

8.2 Gas generation

For larger commercial and industrial customers, solar PV generation may not be a practical option due to the large physical area required to offset the on-site electrical load. For these larger classes of customers, natural gas generation is a practical and economic technology choice for on-site generation. Unlike the capital cost of solar PV technology, natural gas generator costs have remained relatively stable over the past decade. The cost of a large-scale natural gas turbine or reciprocating internal combustion engine is typically around $1,100 per kilowatt (kW) of capacity.

Analysis assumptions

- Analysis in this report focuses on smaller-scale technology, typically a reciprocating internal combustion engine, which is conservatively estimated to cost $2,000 per installed kW of capacity
- Operating costs associated with a generator of this size consist of fuel and operating & maintenance costs for a total variable operating cost of $36.25 per MWh:
  - Fuel costs are conservatively estimated using a 10.5 gigajoule (GJ) per MWh heat-rate and a $2.5 per GJ natural gas cost[7]
  - Variable operating costs of a generator are estimated at $10 per MWh
- System operation is expected to be baseload operation, running at a 95 per cent capacity factor
- Since this analysis focuses primarily on gas generation options less than 5 MW, carbon costs have been excluded; Alberta's *Carbon Competitiveness Incentive Regulation* (CCIR) does not apply to emitters who produce less than 100,000 tonnes of greenhouse gas annually, such as a high efficiency baseload generator of approximately 25 MW of capacity or less
- If an on-site gas generator is expected to exceed this capacity, its emissions cost would be less than $2 per MWh for a high efficiency natural gas generator[8]
- Customers may optimize production by dispatching their facilities in a more dynamic manner; however, for the purposes of this analysis, a baseload operation profile demonstrates a baseline operating condition reflective of a customer that intends to source a significant portion of their power from an on-site generator

8.3 Micro-generation Regulation

The *Micro-generation Regulation*[9] enables grid-connected customers to connect a generator under 5 MW in size to the electric distribution system with the intention of offsetting customer on-site consumption. The *Micro-generation Regulation* separates customers into "Small Micro-generation," representing customers with less than 150 kW of generation capacity, and "Large Micro-generation," representing customers with between 150 kW and 5 MW of

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[7] 2019 natural gas prices in Alberta averaged less than $1.50/GJ. The $2.50/GJ price was conservatively estimated to reflect commodity and delivery costs.

[8] High efficiency natural gas generators can achieve efficiencies better than 8.5 GJ/MWh. If a generator is burning natural gas with an emissions factor of 0.04946 t/GJ, it can achieve an emissions intensity of 0.418 t/MWh. When compared with the 0.37 t/MWh High-performance Benchmark from the *Technology Innovation and Emissions Reduction Regulation*, the unit cost of emissions can be approximated as (0.418 – 0.370) x $30 per tonne = $1.44 per MWh, depending on the heat rate.

[9] http://www.qp.alberta.ca/documents/Regs/2008_027.pdf

generation capacity. Larger generators are not covered under this regulation. Small Micro-generation customers can use cumulative meters and gain credit for their generation that must be applied against load in future billing cycles.

Large Micro-generation customers require interval meters that enable them to sell generation and consume load, based on real-time interval pricing. The intention of the *Micro-generation Regulation* is to enable customers to cover their load, not to generate excess power for sale to the grid. However, the regulation does enable customers to receive credit and payment for excess generation.

8.4 Distributed generation tariff options

Fortis, ATCO, and ENMAX's tariffs each contain a customer class specifically for distribution-connected generation. These tariffs provide an explicit schedule for distribution-connected generation costs. The intention of these rate classes is to reflect charges and credits for independent generators, but they may be applicable in cases where customer generation exceeds customer load.

At present, customers can deliver surplus electricity and receive credit for forgone transmission costs, which can provide a supplemental source of revenue for a distribution-connected generator. These options may convince a customer with on-site generation to oversize their generation equipment to receive the benefits of offset distribution and transmission charges on other loads connected to the same point of delivery.

8.5 Generation options for transmission-connected industrial consumers

Large industrial consumers are frequently sophisticated participants in the electric industry. Many large industrial consumers, especially those large enough to warrant direct connection to the transmission system, install on-site generation to self-supply much of their own load and sometimes export to the electric system any electricity that is surplus to their on-site load.

As illustrated previously in this report, about one-quarter of industrial load is self-supplied by on-site generation. This proportion has increased slowly, at about 1 per cent per year, over the past twenty years. The economics of many industrial self-supply sites are enhanced by the availability of excess process heat that may be used to generate electricity or from the opportunity to simultaneously produce heat and electricity in a cogeneration installation.

8.6 Industrial system designations

Industrial consumers with on-site generation may also apply for an Industrial System Designation (ISD) from the AUC, which provides additional flexibility in location and ownership of the generation. The AUC will make a determination based on the principles outlined in Section 4 of the *Hydro and Electric Energy Act*[10]. A designation must support the economical supply of generation to meet the requirements of integrated industrial processes and efficient exchange of electric energy that is in excess of the industrial system's own requirements. Further, the location of generation and consumption facilities should improve the efficiency of the interconnected electric system, including improved voltage stability and reduced losses and congestion on transmission lines.

A transmission-connected industrial consumer with on-site generation and an ISD is subject to the ISO tariff Supply Transmission Service Rate (STS) and the Demand Transmission Service Rate (DTS) on an instantaneous net flow basis; their instantaneous net supply and consumption position will determine the import or export amount from the site. Therefore, if an industrial customer can match their load and on-site generation precisely, they will minimize their tariff exposure.

Recent decisions by the AUC have created uncertainty as to whether industrial sites without an ISD can both self-supply on-site load and supply surplus generation to the electric system. In its Decision 23418-D01-2019 on the E.L.

[10] http://www.qp.alberta.ca/documents/Acts/H16.pdf

Smith Solar Power Plant application[11], the AUC determined that, where an industrial site is not an ISD and where the *Micro-generation Regulation* does not apply, the owner of a generating unit is prohibited from using that unit to supply on-site load and to export surplus electricity generated by that unit to the electric system.

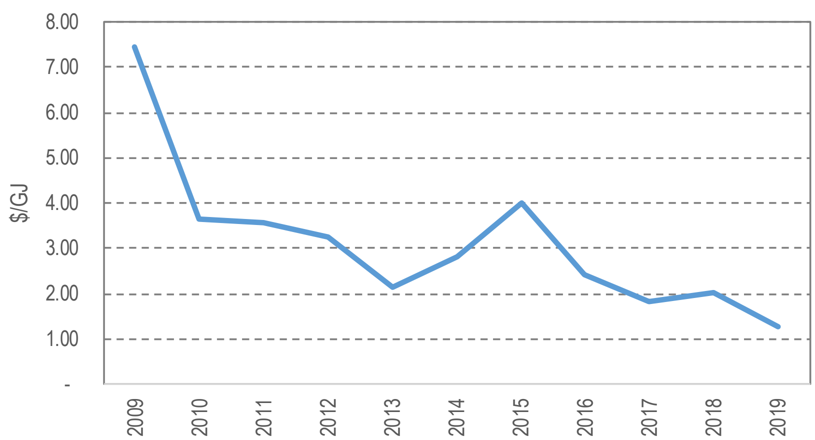
The AUC is currently consulting with stakeholders regarding whether additional exemptions to the prohibition against self-supply and export are appropriate and, if so, the potential regulatory solutions. The outcome of the AUC's consultation could guide industry and impact the incentives to self-supply electricity.

8.7 Trends in self-supply generation costs

While delivered costs of grid-supplied electricity have increased significantly, the cost of certain renewable electricity sources, such as solar PV and wind, has declined materially. IHS Markit reports that rooftop solar PV capital costs have declined from approximately $7.03 CAD per watt in 2009 to $2.83 CAD per watt in 2019, an annual cost decline of 8.7 per cent. If on-site generation costs remain at this level or decline further, certain DFO service territories may experience increased self-supply for loads from smaller customer classes seeking to reduce their electricity costs.

The capital cost of natural gas generators has remained relatively constant over the past decade, while the operating costs have declined significantly as natural gas commodity prices have weakened. The currently depressed natural gas price environment provides favourable economic conditions for on-site natural gas generation. As indicated in Figure 8.7-1, Alberta natural gas prices in 2019 were less than half of the cost that they were in 2009[12]. If low natural gas prices persist into the future, additional on-site generation facilities will likely emerge at industrial and large commercial sites.

Figure 8.7-1: Alberta natural gas prices



With increases in distribution and transmission costs, decreases in on-site generation costs, and accommodating regulations, many customer classes have the ability to install economic generation options to reduce their overall bills. Residential customers in certain distribution service territories may have the incentive to generate their electrical needs via solar PV, while large commercial and industrial customers may be incented to generate electricity using a natural gas-fired generator.

[11] Available at http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2019/23418-D01-2019.pdf

[12] Natural gas prices, available at https://www.alberta.ca/alberta-natural-gas-reference-price.aspx, indicate an annual average price of $3.65 per GJ in 2009 and a price of $1.40 per GJ in 2019.

9. Estimated per unit delivered electricity cost by customer class and distribution service territory with self-supply generation

The following cost estimates review the delivered cost of electricity, with and without on-site generation, in 2009, 2014, and 2019 to provide a perspective of the trends in self-supply economics.

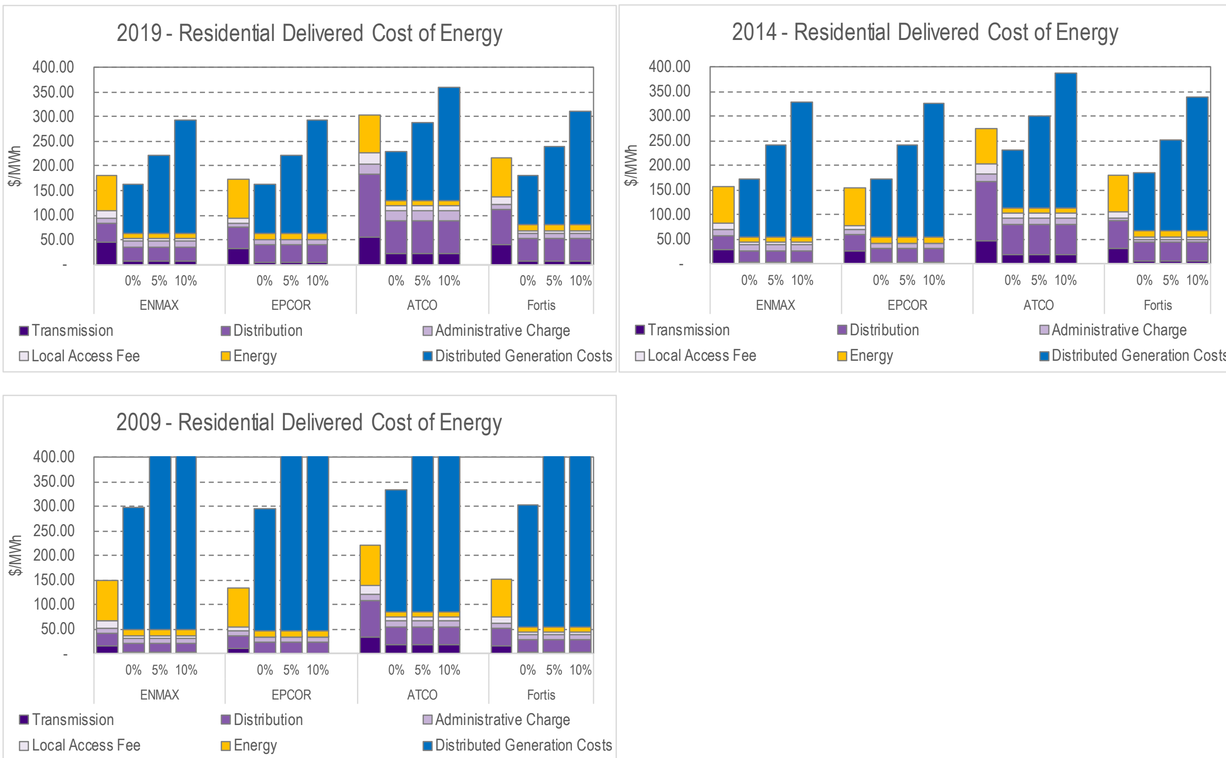
The stacked bar charts demonstrate the delivered cost of grid-supplied electricity and compare that to the cost profile of a customer with an on-site generator. Since on-site generators require capital investment, costs based on a range of required returns from 0 per cent to 10 per cent are illustrated. This is intended to reflect a range that might attract niche investors, i.e., a 0 per cent return representing those simply looking to cover their costs, or pursue green initiatives, and financially motivated investors, i.e., those looking at on-site generation in the context of a financial investment, requiring a 10 per cent return.

The second set of linear trend graphs demonstrates the potential growth in grid-supplied delivered electricity costs, based on expected annual increases to the Performance Based Regulation (PBR) formulas for each service territory. Transmission cost growth rates are consistent with projects identified in the *AESO 2020 Long-term Transmission Plan.* These increasing grid-supplied electricity costs contrast with the decreasing or flat projections for on-site generation-delivered electricity costs. The grey shaded area represents a range of delivered cost projections when on-site generation is used, based on expected tariff costs combined with the costs associated with on-site generation. The on-site generation costs include the capital and operating costs associated with installing and operating an on-site generator, as well as a 10 per cent return on capital.

In the case of natural gas-fired generation, these costs include fuel costs (estimated using forward prices) and operation and maintenance costs. None of the on-site generation costs incorporate carbon costs or credits (neither offsets nor renewable electricity certificates). The delivered cost of electricity with on-site generation also incorporates the grid-based electricity costs, including the tariff costs and the commodity costs for electricity consumed when on-site generation is unavailable. These commodity costs were estimated using the forward curve for electricity.

9.1 Residential

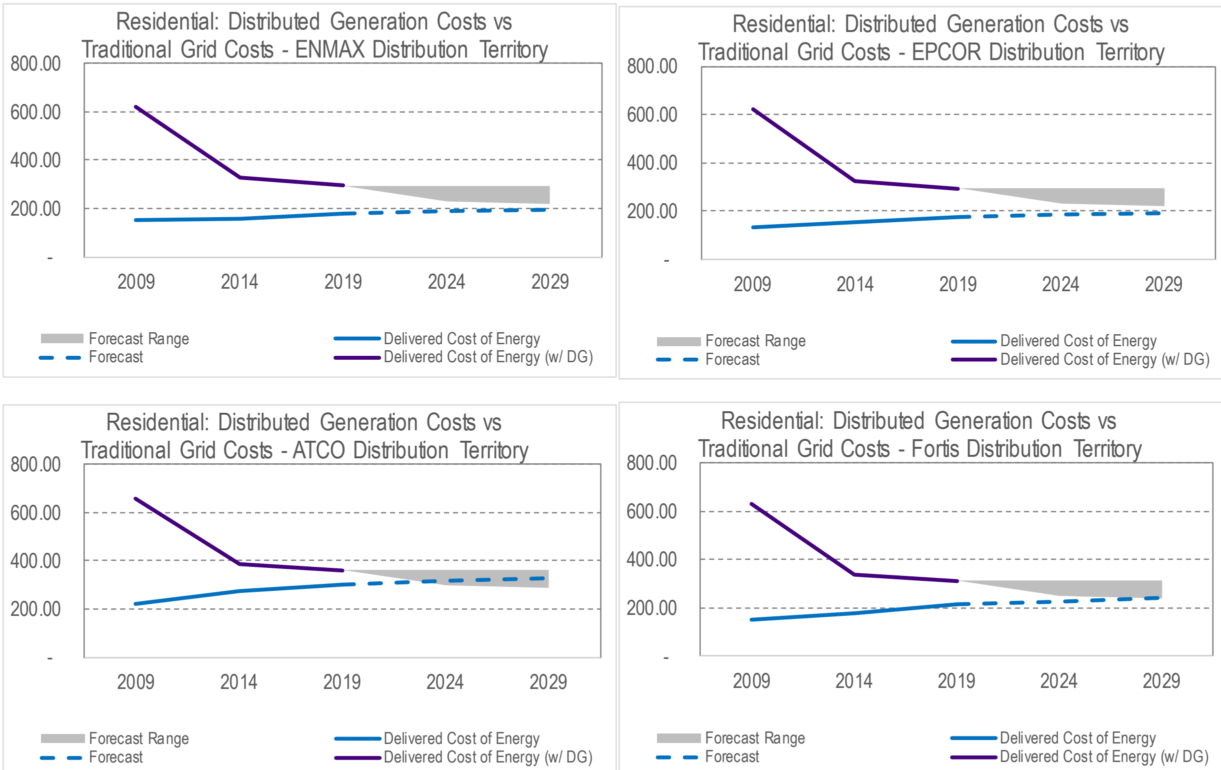
Figure 9.1-1: Residential – delivered cost of electricity over time, across service territories



While the traditional delivered cost of electricity has increased with distribution and transmission costs, the overall cost of residential rooftop solar panels has declined significantly. With capital costs of $7 per watt, the levelized cost of solar electricity for a residential household was between $300 and $600 per MWh in 2009 (depending on the capital return or discount rate applied to the project). By 2014, residential solar capital costs had declined to $3.34 per watt, which equates to a levelized cost of delivered solar electricity between $172 and $386 per MWh.

At this cost, residential rooftop solar could only be competitive in ATCO's service territory, and only if a very low discount rate is applied. However, by 2019, the cost of rooftop solar had declined enough to make PV competitive with grid-delivered electricity in each service territory, at low discount rates. If the cost of solar generation continues to decrease while the cost of traditionally delivered electricity increases, there is additional scope for residential customers to augment their grid connections with solar PV panels.

Figure 9.1-2: Residential – distributed generation costs vs. traditional grid costs over time, across service territories

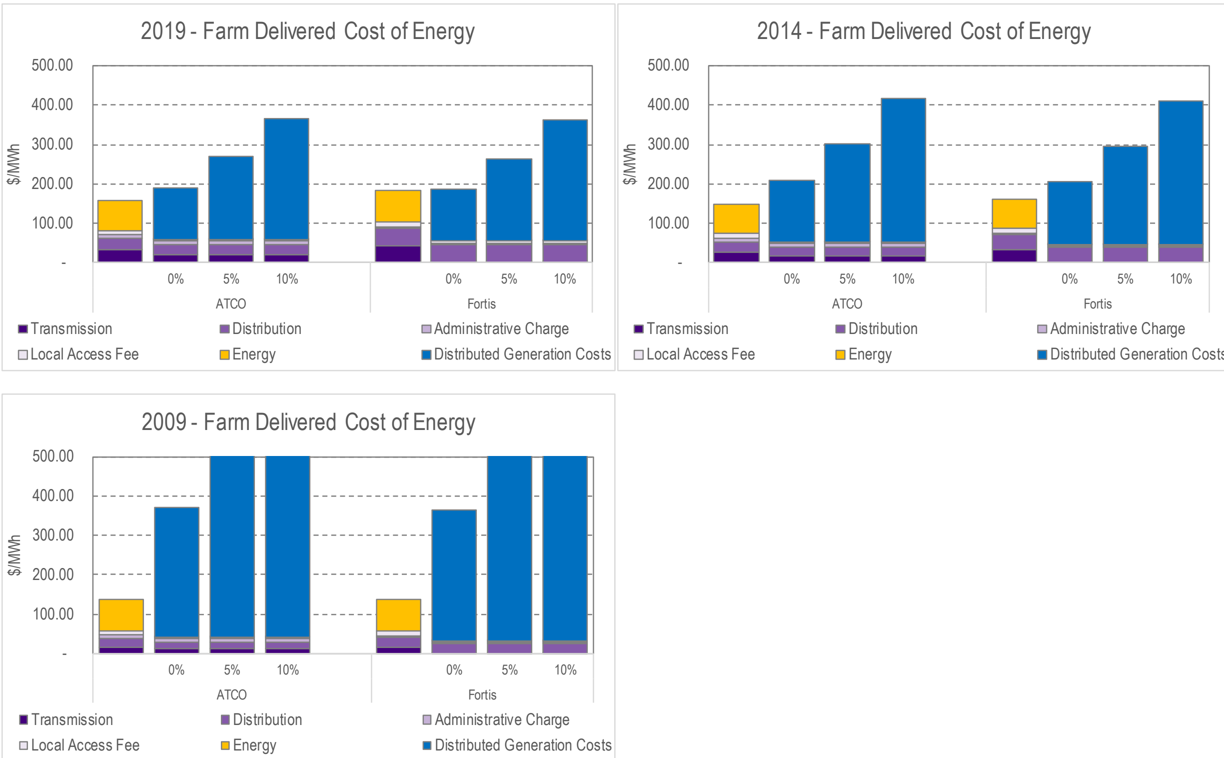


The trend figures above demonstrate the potential increase in traditional delivered cost of electricity and delivered cost of electricity with distributed generation, i.e., self-supply. The distributed generation cost includes a 10 per cent return on capital. The distributed generation was sized to cover almost all of the on-site load requirements on an annual basis. The distributed generation forecast range reflects PV cost-decline projections from IHS Markit research, combined with the balance of tariff costs. The traditional delivered cost line indicates the expected tariff cost increases based on PBR growth rate forecasts from each DFO.

In the near future, certain residential customers may be able to achieve a 10 per cent return by installing solar PV generation at their residence. If lower returns are acceptable, due to social objectives or preferences, solar PV may be an attractive option already.

9.2 Farm

Figure 9.2-1: Farm – delivered cost of electricity over time across service territories



Farm customers in ATCO and Fortis service territories incur lower delivered electricity costs than residential customers. Although the delivered cost of grid-supplied electricity has increased over the past decade, the cost of rooftop solar generation remained uncompetitive with grid-supplied electricity until very recently. Farm customers have a larger fixed portion of their overall delivered cost of electricity related to customer charges and peak demand charges. In Alberta, farm customer peak demand will not change after solar PV installation because it is based on the installed breaker size.

Farm customers should not currently expect cheaper electricity from on-site solar generation, but if PV costs decline further, then solar PV may become attractive to farm customers with low discount rates.

Figure 9.2-2: Farm – distributed generation costs vs. traditional grid costs by service territory

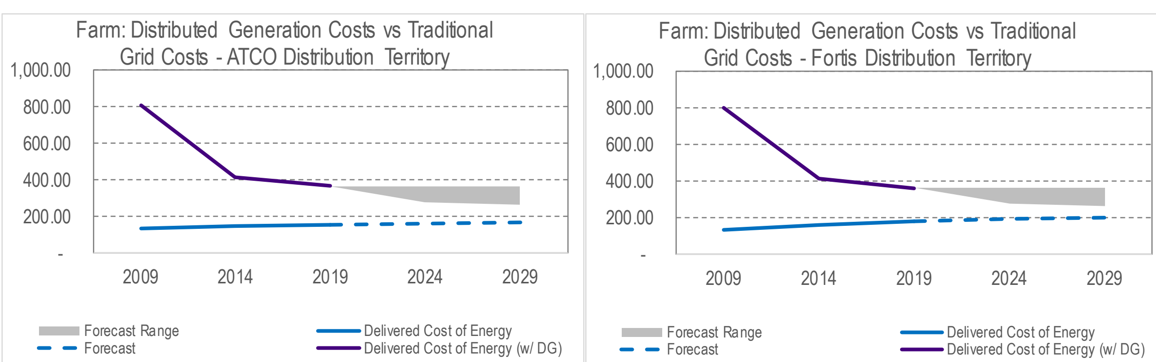
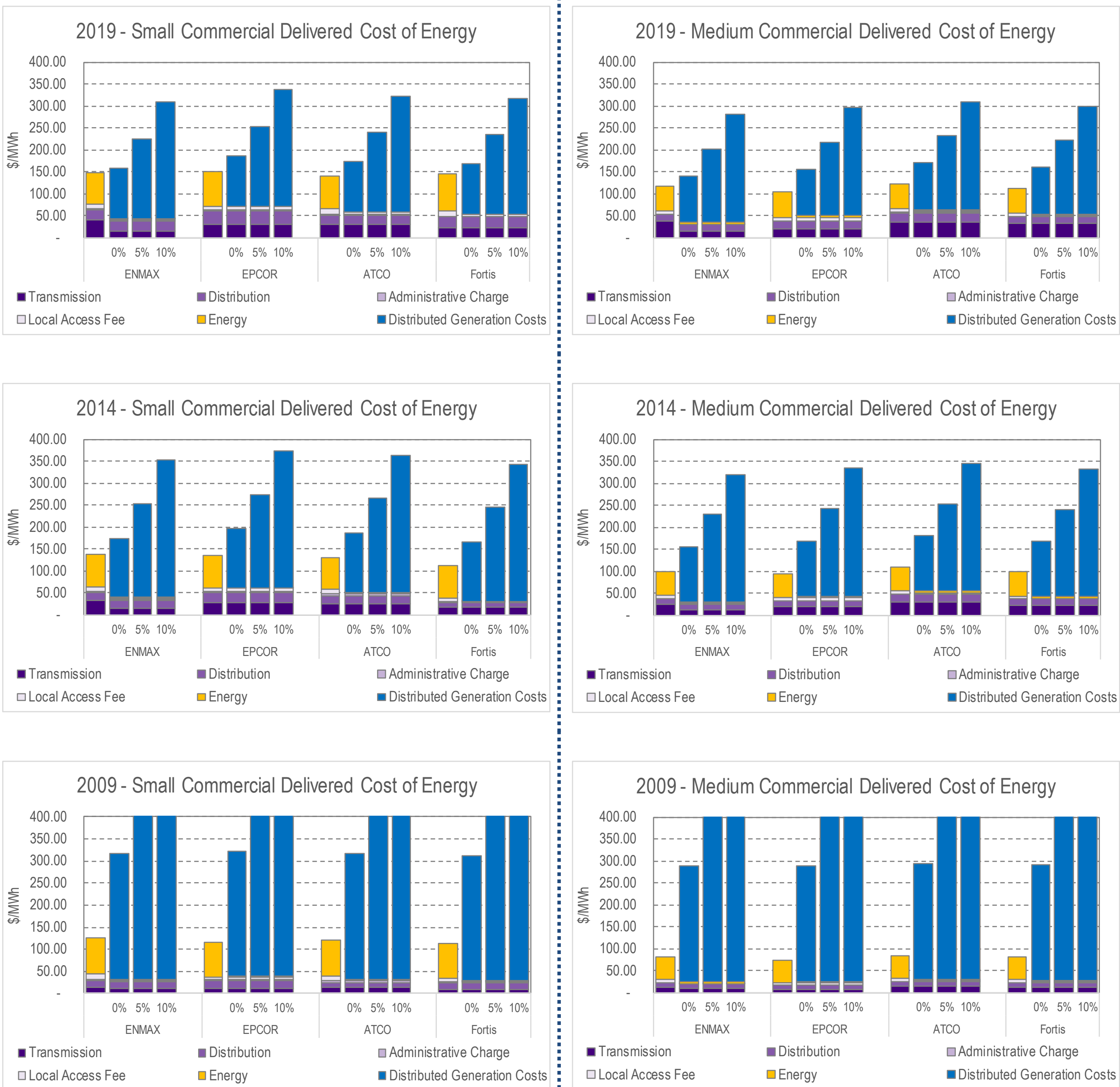


Figure 9.2-2 indicates that the traditional delivered cost of electricity for farm customers is expected to continue to increase, while the delivered cost of electricity including distributed generation continues to decline.

9.3 Small commercial / medium commercial

Figure 9.3-1: Small and medium commercial – delivered cost of electricity over time across service territories

Small commercial | **Medium commercial**



Small and medium commercial customers receive delivered electricity at a lower cost than farm or residential customers. For these customer classes, the traditional delivered cost of electricity is meaningfully lower than the cost of producing on-site solar PV electricity.

At this time, small and medium commercial customers would not expect to receive an economic benefit by installing a solar PV system. However, if solar PV costs continue to decline while distribution and transmission costs increase, the economics of self-supply for small commercial customers could improve enough to incent customers to make the capital investment associated with solar self-supply.

Figure 9.3-2: Small commercial – distributed generation costs vs. traditional grid costs by service territory

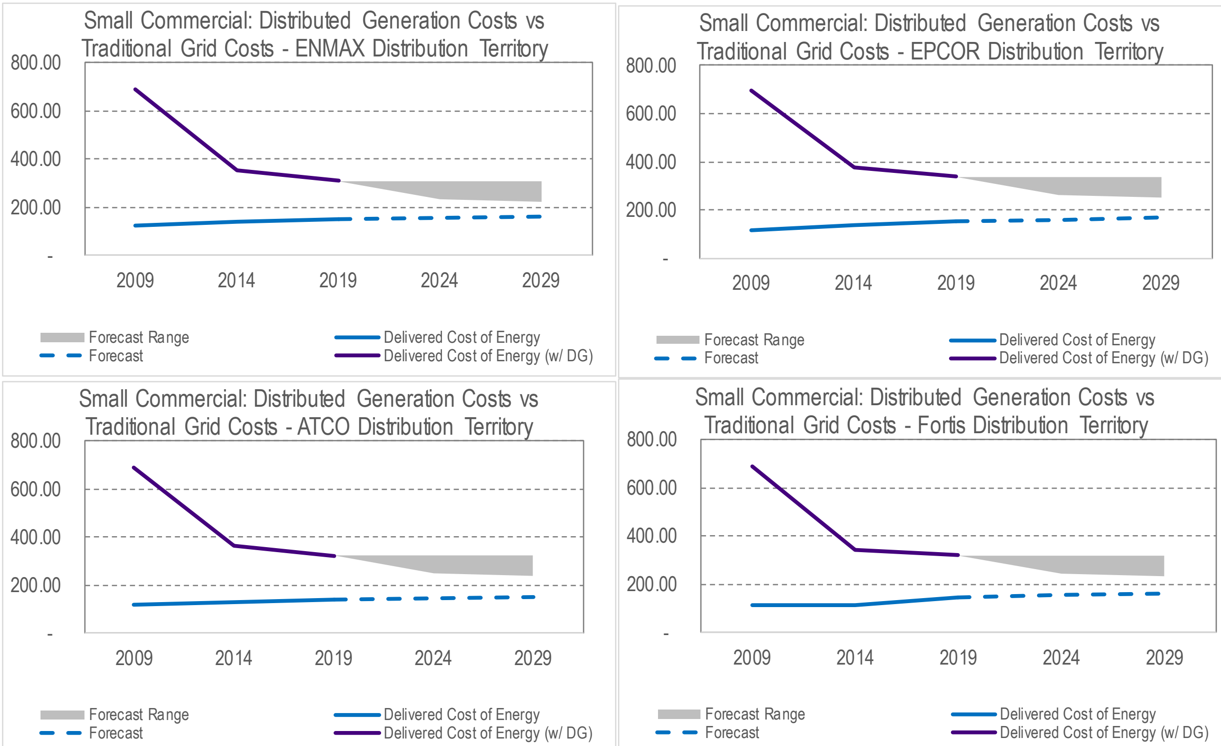
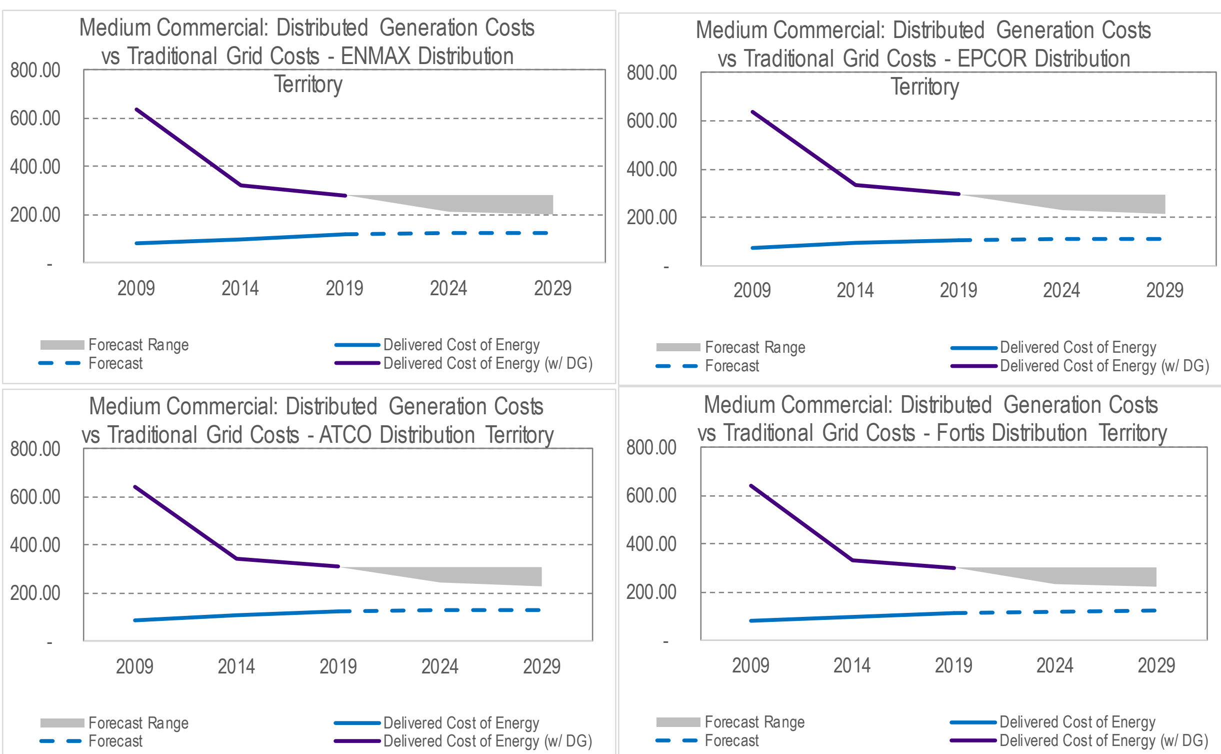


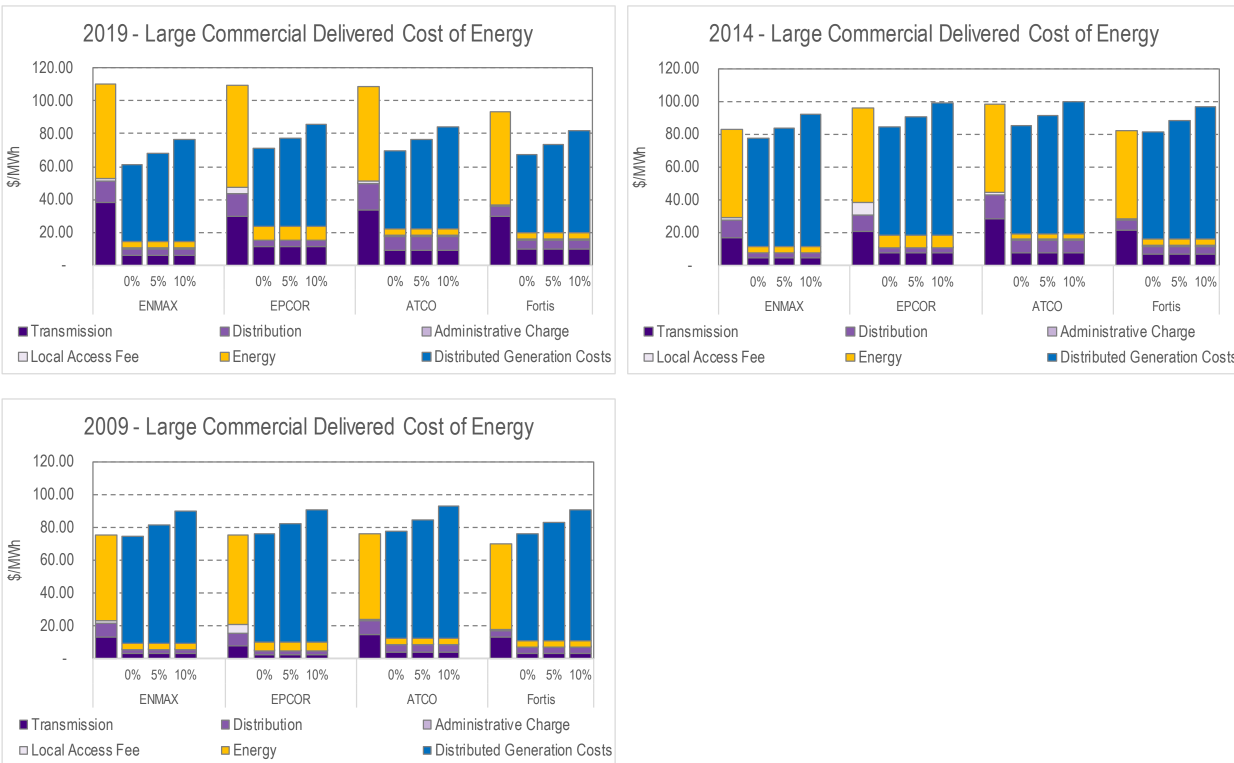
Figure 9.3-3: Medium commercial – distributed generation costs vs. traditional grid costs by service territory



The small and medium commercial customers are expected to see increased traditional delivered electricity costs. The forecast cost of solar generation is not expected to provide these customers with a 10 per cent return on capital. However, the trend of increasing traditional costs and decreasing solar PV generation costs may provide an attractive investment with a lower return to small and medium commercial consumers.

9.4 Large commercial

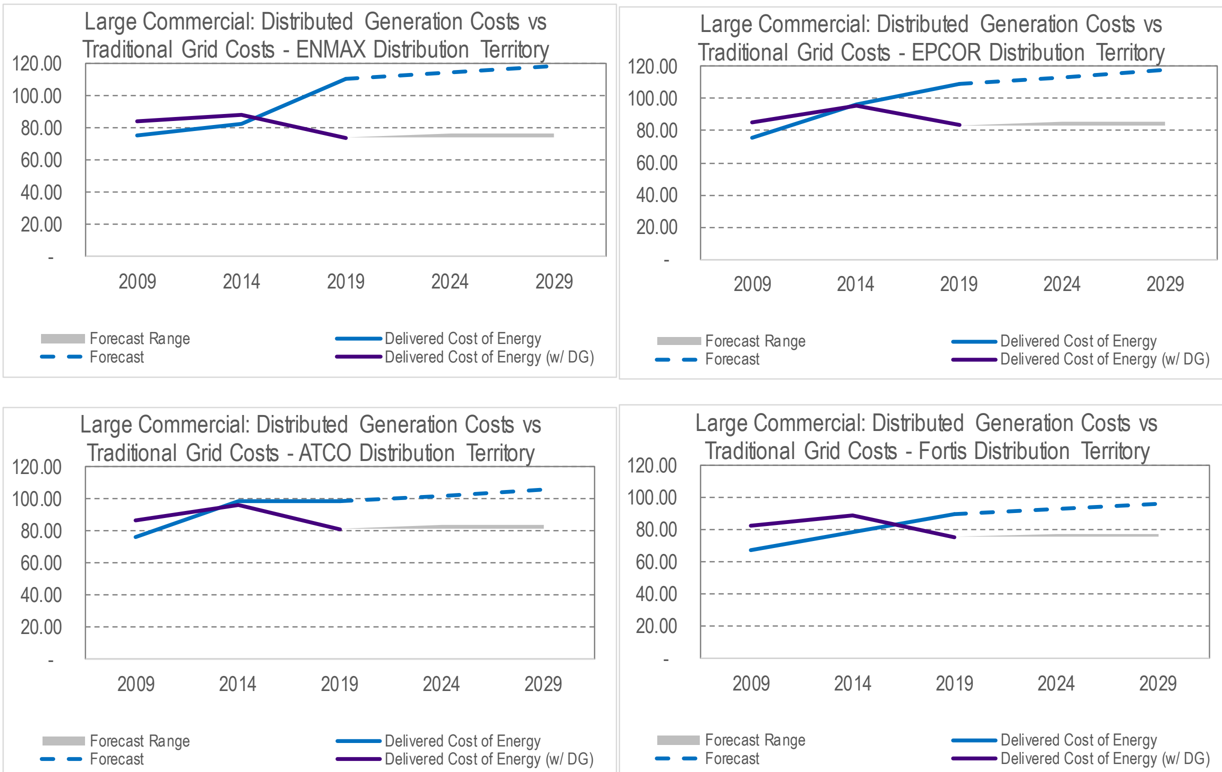
Figure 9.4-1: Large commercial – delivered cost of electricity over time across service territories



The large commercial customer load profile examined is approximately 1.9 MW of average load and 3.1 MW of peak load. If the customer site is not very large, it may not be practical to install a sufficient quantity of solar panels to cover a substantial portion of the customer's load. Furthermore, large commercial customers have enough electrical capacity to consider matching their load with on-site natural gas-fired generation. By 2019, the case for installing natural gas generation at large commercial customer sites appears relatively strong. The capital costs associated with natural gas generation have remained relatively constant and natural gas costs have declined materially, while the traditional delivered cost of electricity has increased materially. As a result, the economics of natural gas-fired generation are favourable for the average large commercial customer in all of the major service territories.

The decision to add a natural gas generator may be impacted by qualitative issues as well as economics. Siting issues such as noise and required space could impede the decision to install natural gas generation on-site. Additionally, some customers may not want to invest in complex machinery that may impact their base operations or require them to add capital costs which compete with capital additions in their core business.

Figure 9.4-2: Large commercial – distributed generation costs vs. traditional grid costs by service territory

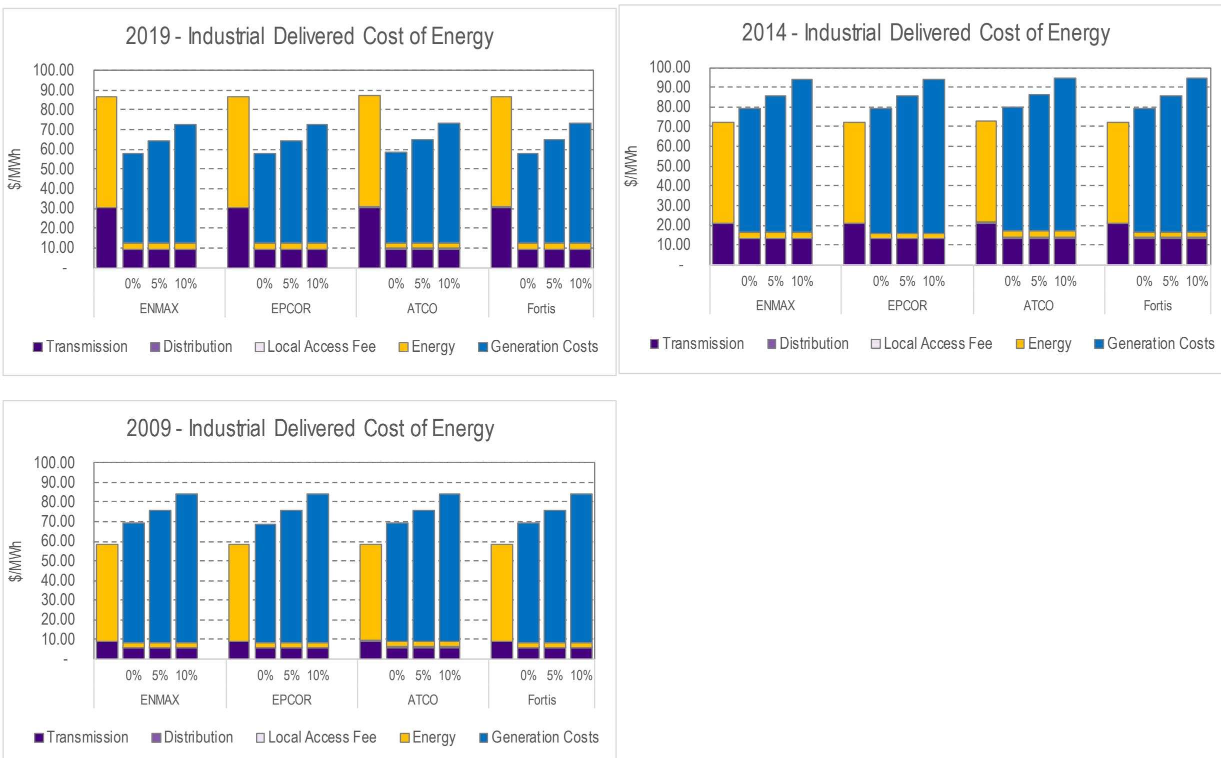


The historical delivered cost of electricity with distribution-connected gas generation has changed based on the underlying costs associated with the capital and operating costs of the generator and the increases in the distribution and generation tariffs. From 2009 to 2014, the distribution and transmission costs increased the delivered cost of electricity with distribution-connected gas generation for large commercial customers. The natural gas commodity price had declined significantly by 2019, which offset increased delivery costs.

Large commercial customers could currently benefit from distributed efficient natural gas generation. The cost of distributed natural gas generation is expected to remain relatively flat, while traditional grid supplied-electricity is anticipated to continue to increase. For large commercial customers who are able to connect a natural gas generator to their infrastructure, distributed generation can provide a return on their capital investment greater than 10 per cent. These economics are anticipated to persist into the foreseeable future.

9.5 Industrial

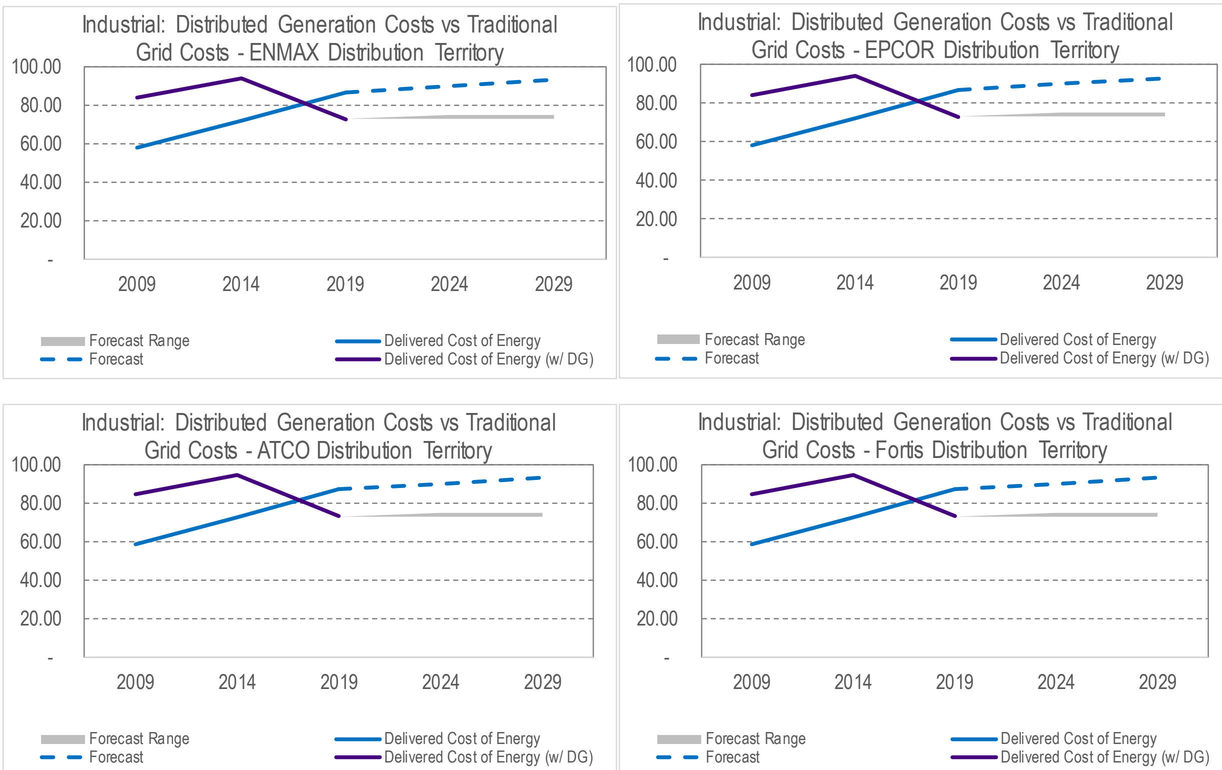
Figure 9.5-1: Industrial – delivered cost of electricity over time across service territories



Industrial customers have the lowest delivered cost of electricity among the major customer classes in Alberta. As a result, the economics are not as favourable for an on-site natural gas generator as they would be for a customer that is offsetting higher traditional electricity delivery costs. If an industrial customer installs an on-site generator connected to the distribution system, it may be subject to the *Micro-generation Regulation*. If the customer is transmission-connected, however, it will be subject to demand charges associated with delivery (DTS) and supply charges associated with generation (STS).

Larger transmission-connected industrial customers can apply for an ISD with the AUC. If approved for an ISD, the industrial customer's site may be eligible for net metering, whereby the customer only pays for the net generation exported or net load imported from their facility, effectively providing it with similar tariff treatment to a micro-generator.

Figure 9.5-2: Industrial – Distributed generation costs vs. traditional grid costs by distribution service territory



Industrial customers may already benefit from distributed efficient natural gas generation. With the cost of distributed generation expected to be flat for the foreseeable future, and the expected increase in traditional delivered cost of electricity, the incentive to install on-site generation may remain attractive to industrial customers who are able to achieve approval for an ISD or to customers who may be able to interconnect under the *Micro-generation Regulation*.

The economics represented in Figure 9.6-2 reflect the delivered cost of electricity with on-site generation, either with an ISD or under the *Micro-generation Regulation*. Industrial customers who cannot fit under these regulatory mechanisms may not benefit materially from on-site generation, since they will be subject to the DTS and STS tariff charges on a gross consumption and gross production basis.

For an industrial customer subject to both STS and DTS, the decision to add on-site generation would not reduce their net transmission and distribution charges. The decision would be based entirely on whether they could produce electricity more economically than the commodity would otherwise cost.

Similar to other types of consumers, the decisions of industrial consumers whether or not to use on-site generation also reflect other considerations. One or more of the following factors may have a greater weight than economic benefits on an industrial consumer's self-supply decision:

- Focus on core business rather than alternative purposes for capital spending
- Complexity associated with operations and regulatory burden
- Exposure to additional fuel price volatility
- Preference to focus on core capabilities rather than incorporate electricity generation into its operations
- Opportunity to diversify into other revenue streams, such as sale of excess generation
- Opportunity to simultaneously produce heat and electricity in a cogeneration installation
- Regulatory uncertainty that may result in changes to relative economics

The stability of the proportion of industrial load that is self-supplied suggests that these non-economic factors may be a primary determinant of an industrial consumer's decision to self-supply with on-site generation.

10. Conclusion

Technology and economics increasingly provide options for grid-connected customers to augment their consumption of electricity with on-site generation sources. Customers across Alberta have the ability to switch a portion of their electricity consumption to self-supply through micro-generation options or through an application to the AUC for an ISD.

The incentive to generate electricity on-site is increasingly attractive as distribution, transmission, and commodity costs increase, while self-generation costs decline. Certain customer classes in the distribution service territories may already benefit from on-site generation, while other customer types can still consume electricity most economically from the grid. If the trend of increasing distribution and transmission costs continues while on-site generation costs remain flat or decrease, these incentives may continue to motivate self-supply.

The regulatory framework involving on-site generation continues to evolve, and the AESO will monitor changes and issues as they progress. The AESO must remain cognizant of the increasing distribution and transmission tariff costs that customers incur in order to supply customers with the most cost-effective means of delivering electricity.

Key factors to monitor which influence incentives to self-supply include:

- **Technology costs for solar:** costs have steadily and significantly decreased over the past decade; if the pace is maintained, the likelihood increases that residential through medium commercial customers will adopt solar to independently supply their energy needs
- **Grid costs:** future increases in distribution and transmission costs
- **Regulations:** treatment of self-supply
- **Carbon costs:** could impact on-site generation options: may increase relative costs for gas generation, while adding potential revenue for renewable or cogeneration options
- **Natural gas pricing:** increases may make self-supply options for larger commercial and industrial customers less attractive
- **Investment considerations:** attractiveness of investment alternatives, access to capital, cost of capital, operational considerations