AESO 2018
Annual Market Statistics

MARCH 2019

Contents

Executive summary

The Alberta Electric System Operator (AESO) facilitates a fair, efficient and openly competitive market for electricity and provides for the safe, reliable and economic operation of the Alberta Interconnected Electric System (AIES). The AESO is responsible for designing and implementing Alberta's transition from an energy market to a new framework that includes an energy market and a capacity market. This process is expected to take three years and a capacity market is anticipated to be in place by November 2021.

The Annual Market Statistics report provides a summary of key market information over the past year and describes historical market trends. The accompanying data file provides stakeholders with the data that underlies the tables and figures in this report.

In 2018, 201 participants in the Alberta wholesale electricity market transacted approximately $6.6 billion of energy. The annual average pool price for wholesale electricity increased 127 per cent from its previous-year value to $50.35/MWh. The average natural gas price fell 30 per cent, averaging $1.44/GJ. The average spark spread based on a 7.5 GJ/MWh heat rate increased to $39.68/MWh from its previous-year value of $6.82/MWh.

The average Alberta Internal Load (AIL) increased by three per cent over 2017 values, and hourly load set a new seasonal peak record in summer due to relatively warm weather conditions.

Price	2018	Year/Year Change
Pool price	$50.35 /MWh	+127%
Gas price	$ 1.44 /GJ	-30%
Spark spread at 7.5 GJ/MWh	$39.68 /MWh	+484%

Load	2018	Year/Year Change
Average AIL	9,741 MW	+3%
2018 Winter peak	11,205 MW	-4%
2018 Summer peak	11,169 MW	+3%

The installed generation capacity decreased three per cent in 2018 due to coal generation retirements. However, energy produced from coal generation continued to serve most of Alberta's load.

Gas generation supplied 42 per cent of Alberta's net-to-grid energy which is a 12 per cent increase from 2017. This increase shows that gas generation had a larger share in the baseload generation in 2018.

Alberta was a net importer of electricity along all interties in 2018. Imports to the province increased 162 per cent from 2017 levels driven by high prices in Alberta and a relatively wet year in the Pacific Northwest. Exports decreased by 29 per cent.

Price of electricity

Pool price averaged $50.35/MWh

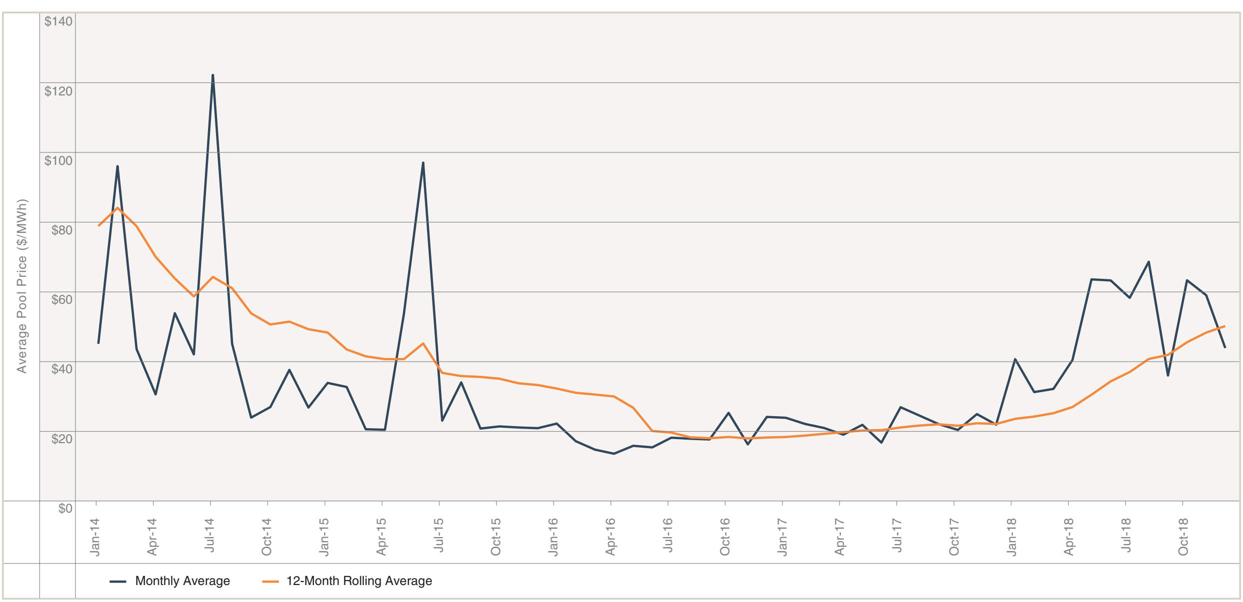
Pool price averaged $50.35/MWh over 2018—an increase of 127 per cent from 2017. In this report each day is separated into on-peak and off-peak periods: on-peak periods start at 7 a.m. and end at 11 p.m.; the remaining hours of the day make up the off-peak period. In 2018, the average pool price during the on-peak period increased 142 per cent to $59.28/MWh, and the off-peak average pool price increased 84 per cent to $32.47/MWh. Table 1 summarizes historical price statistics over the 10-year period between 2009 and 2018.

TABLE 1: Annual market price statistics

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Pool price ($/MWh)										
Average	47.81	50.88	76.22	64.32	80.19	49.42	33.34	18.28	22.19	**50.35**
On-peak average	58.04	62.99	102.22	84.72	106.13	61.48	40.73	19.73	24.46	**59.28**
Off-peak average	27.36	26.67	24.22	23.51	28.29	25.28	18.55	15.37	17.64	**32.47**
Spark spread at 7.5 (GJ/MWh)										
Average	19.6	22.5	50.4	47.3	57.6	17.6	14.1	2.8	6.8	**39.7**

The pool price sets the wholesale price of electricity—the settlement price for all transactions in the energy market. Figure 1 shows the monthly distribution of prices over the past five years. Over 2018, the monthly average pool price ranged from a low of $31.32/MWh in February to a high of $68.80/MWh in August. The 12-month rolling average shows that pool price has increased but still remained relatively below historical average levels.

FIGURE 1: Monthly average pool price



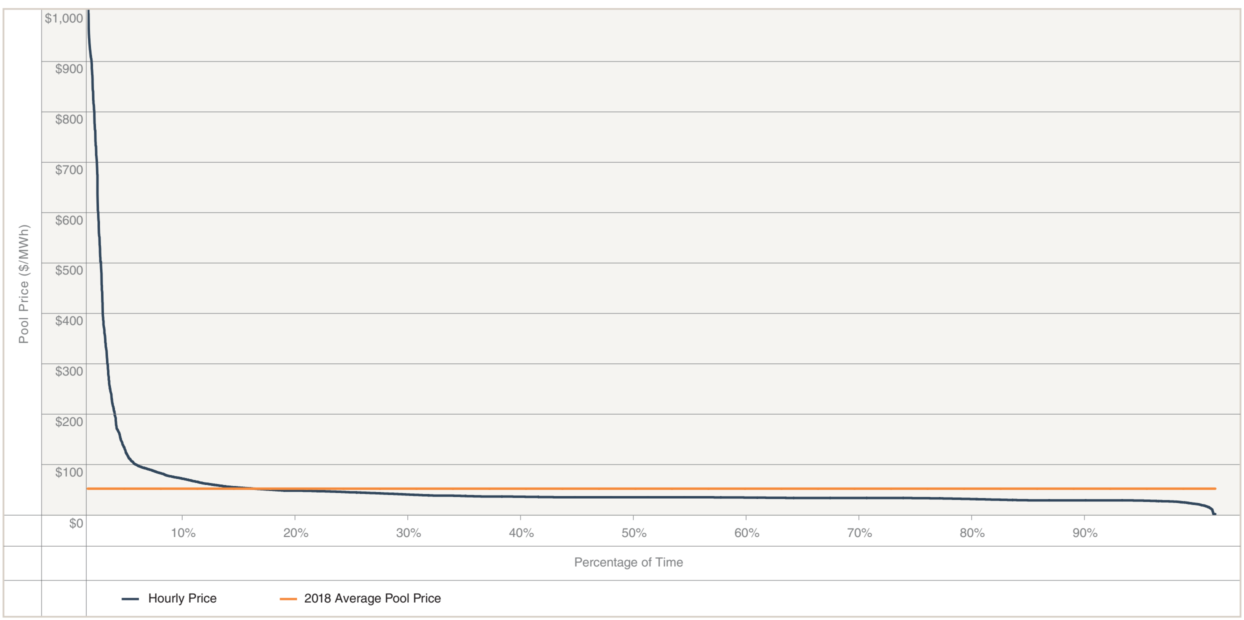
The hourly price of electricity in Alberta is determined according to the economic principles of supply and demand. Generators submit offers specifying the amount of power that they will provide in a one-hour settlement period and the price at which they are willing to supply it. This offer price can range from a low of $0/MWh to a maximum of $999.99/MWh. The automated Energy Trading System arranges offers from lowest to highest price. The sorted list of energy offers is called the merit order.

The system controller dispatches generating units from the merit order in ascending order of offer price until supply satisfies demand. Dispatched units are said to be in merit; units that are not dispatched are out of merit. The highest priced in-merit unit in each minute is called the marginal operating unit and sets the system marginal price for that one-minute period.

The pool price is the simple average of the 60 system marginal prices in the one-hour settlement interval. All energy generated in the hour and delivered to the AIES receives a uniform clearing price—the pool price—regardless of its offer price. System load draws energy from the grid and pays the uniform clearing price.

The price duration curve represents the percentage of hours in which pool price equaled or exceeded a specified level. Figure 2 shows pool price duration over the 2018 year. The hourly price of electricity exceeded the annual average in 15 per cent of hours or approximately one hour of every seven; however, because electricity was more expensive in these hours, they exerted an upward influence on the average price.

FIGURE 2: 2018 pool price duration curve



The reliability of the AIES depends on the ability of system controllers to dispatch supply to serve system load. During supply shortfall and supply surplus conditions, generation may be unavailable for dispatch. Left unaddressed, these system conditions could threaten the stability of the AIES. In order to preserve system stability, system controllers must follow prescribed mitigation procedures to restore the balance between supply and demand.

Supply shortfall conditions occur when Alberta load exceeds the total energy available for dispatch from the merit order. When system shortfall conditions occur, according to the mitigation procedure, system controllers may halt exports, re-dispatch imports and ancillary services, and finally, curtail firm load. When the system operator is forced to curtail load, the system marginal price is set to the administrative price cap of $1,000/MWh. The last load curtailment event occurred on July 2, 2013.

Supply surplus events occur when the supply of energy offered to the market at $0/MWh exceeds system demand. The mitigation procedure for supply surplus events authorizes system controllers to halt imports, re-schedule exports, and curtail or cut in-merit generation. The AIES was in supply surplus conditions for 15 hours in 2018: seven hours in April, six hours in May, and two hours in June. All supply surplus events were successfully resolved.

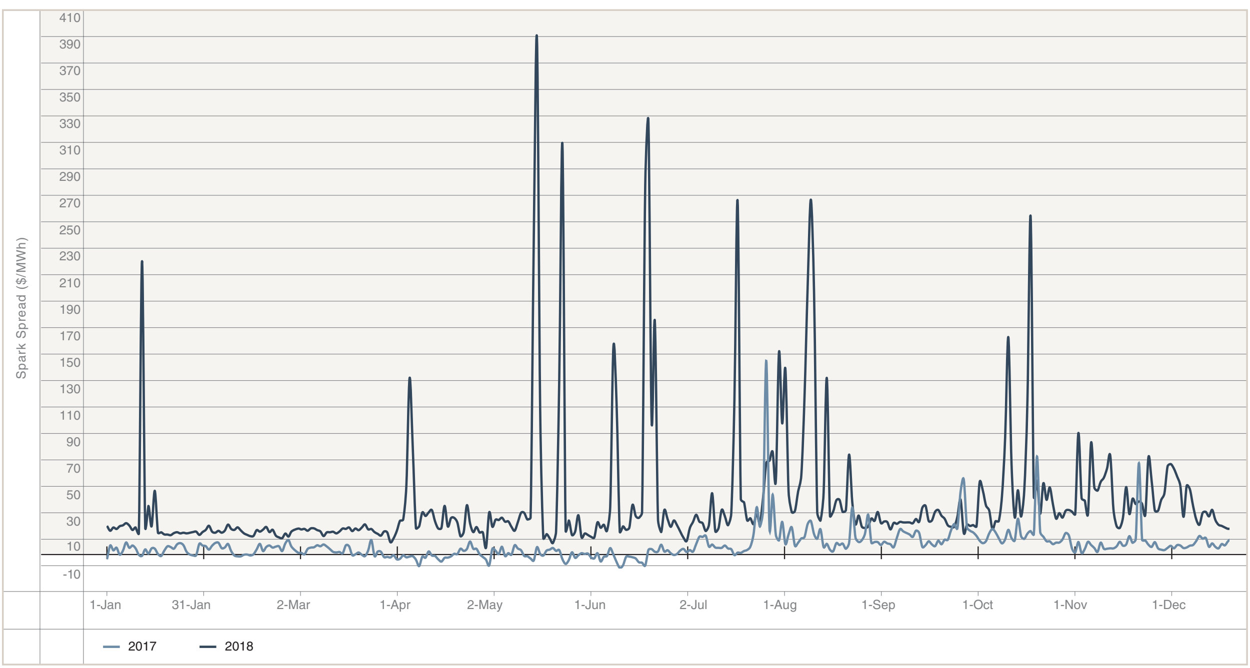
Spark spread increased significantly

The spark spread is a high-level measurement that approximates the profitability of operations of a natural gas baseload generation asset in the energy market, a combined-cycle plant in this calculation. The hourly spark spread is the difference between the wholesale price of electricity and the cost of fuel required to generate that electricity. The cost of fuel is calculated as the product of the operating heat rate and the unit price of natural gas. The operating heat rate measures the efficiency of the generation asset. It represents the amount of fuel energy required to produce one unit of electrical energy. Operating heat rates vary between generating units. This report uses an operating heat rate of 7.5 GJ/MWh in order to assess market conditions for a reasonably efficient combined-cycle gas generation asset.

Positive spark spread implies that baseload operation would be profitable for gas-fired generators; negative spark spread implies that baseload operation would be unprofitable. Spark spread is indicative and does not include costs such as variable operations and maintenance and the cost of carbon.

Figure 3 shows the daily average spark spread for 2017 and 2018. In 2018, the average spark spread increased 484 per cent to $39.68/MWh. The increase in the spark spread is due to pool price spikes and falling natural gas prices observed in 2018.

FIGURE 3: 2017 and 2018 daily average spark spreads



Alberta Internal Load

In this report, all annual load statistics are reported based on the calendar year that starts January 1 and ends December 31 of the same year. However, the seasonal load statistics are reported based on a seasonal year. The winter season starts on November 1 and ends on April 30 of the following year and summer season starts on May 1 and ends on Oct 31. In the seasonal load discussions in this report, the terms winter and summer are referring to these season definitions.

Average load grew three per cent

Table 2 summarizes annual demand statistics over the past 10 years. In 2018, average Alberta Internal Load (AIL) increased three per cent to 9,741 MW, and annual peak load set a new record at 11,697 MW on January 11. The load growth was driven mostly by the increased load from the oilsands, refineries, and cryptocurrency mining.

TABLE 2: Annual load statistics

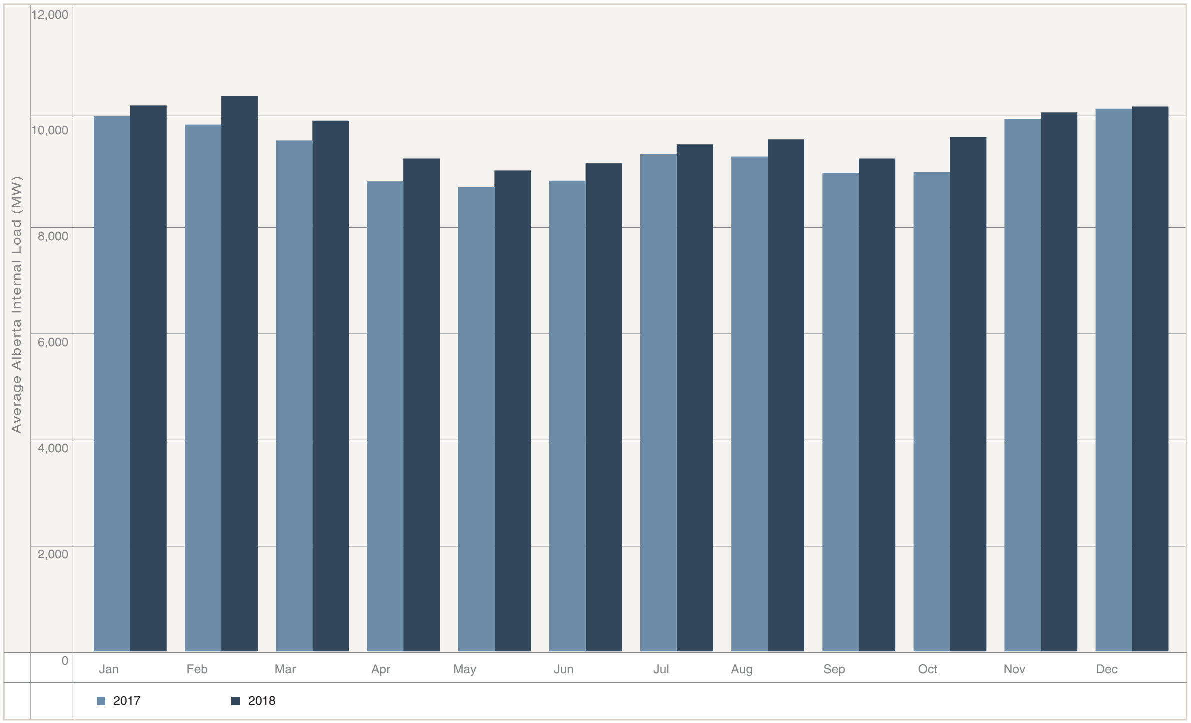
Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Alberta Internal Load										
Total (GWh)	69,914	71,723	73,600	75,574	77,451	79,949	80,257	79,560	82,572	**85,330**
Average (MW)	7,981	8,188	8,402	8,604	8,841	9,127	9,162	9,057	9,426	**9,741**
Maximum (MW)	10,236	10,196	10,226	10,609	11,139	11,169	11,229	11,458	11,473	**11,697**
Minimum (MW)	6,454	6,641	6,459	6,828	6,991	7,162	7,203	6,595	7,600	**7,819**
Average growth	0.2%	2.6%	2.6%	2.4%	2.8%	3.2%	0.4%	-1.1%	4.1%	**3.3%**
Load factor	78%	80%	82%	81%	79%	82%	82%	79.0%	82.2%	**83.3%**
System load										
Average (MW)	6,434	6,550	6,699	6,791	6,903	7,132	7,110	7,030	7,220	**7,287**

AIL is the sum of system load and behind-the-fence load. System load represents the total electric energy delivered to consumers in Alberta through the AIES, including transmission losses. Behind-the-fence load represents the total electric demand in Alberta that is served by on-site generation. Behind-the-fence load usually occurs at industrial sites and is typically served by cogeneration gas facilities.

The load factor represents the ratio of the average AIL to the maximum AIL in each year. A low load factor indicates that load is highly volatile and occurs when peak hourly load significantly exceeds the average load over the year. A high load factor indicates that load is relatively stable and occurs when the peak hourly load is not significantly higher than the average load. The high load factor in Alberta indicates stable load, due largely to strong industrial demand.

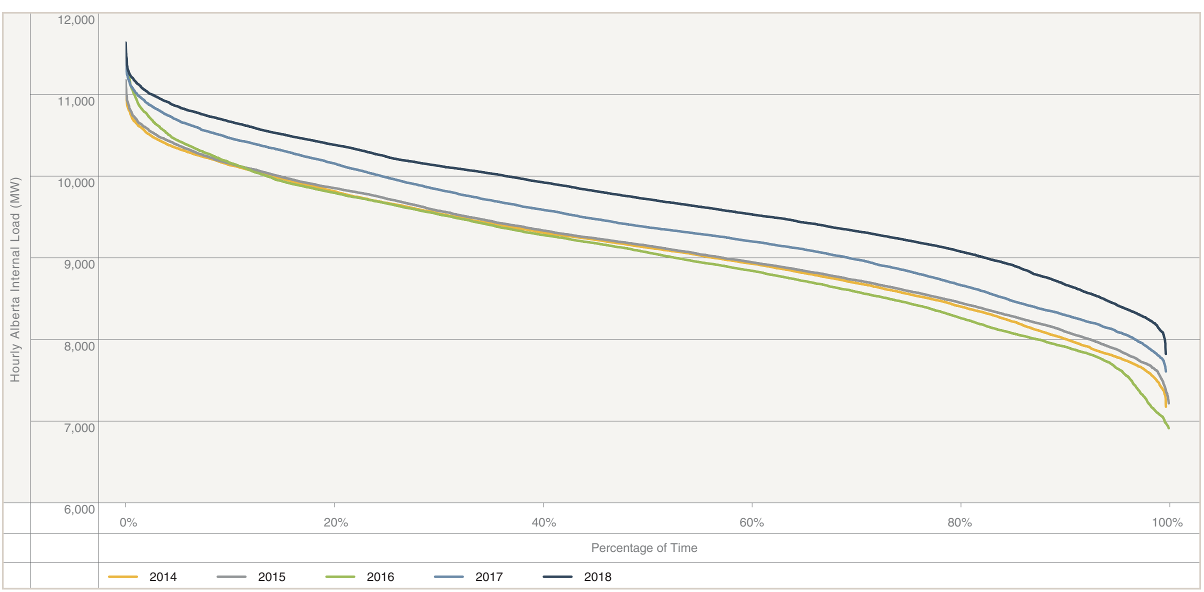
Figure 4 shows the monthly average load in 2017 and 2018. The monthly average load in 2018 was consistently above monthly 2017 levels. Load reached a new annual peak in January due to relatively cold weather conditions. Warm summer weather also led to a new all-time summer peak load in August. However, winter temperatures in late 2018 were unseasonably temperate leading to a relatively small increase in load in November and December.

FIGURE 4: Monthly average load



The load duration curve represents the percentage of time that AIL was greater than or equal to the specified load. Figure 5 plots the annual load duration curve for each of the last five years. This figure shows that while peak load in 2018 increased only slightly over its previous-year value, hourly load in 2018 was higher than any previous year.

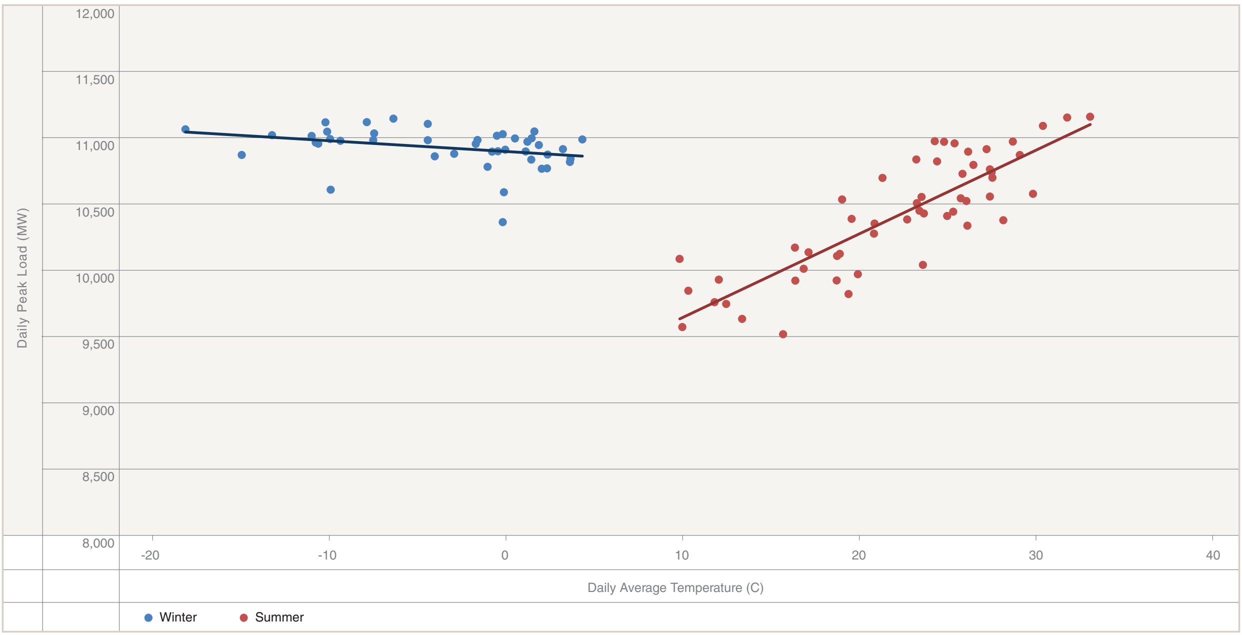
FIGURE 5: Annual load duration curves



Seasonal load

Temperature exerts influence on load. AIL tends to increase as the temperature becomes more extreme. Figure 6 illustrates the relationship between temperature and daily peak demand in weekdays over 2018. On winter weekdays, a decrease of one degree Celsius increased peak load by an average of 8 MW. During summer weekdays, an increase of one degree Celsius increased peak load by an average of 63 MW.

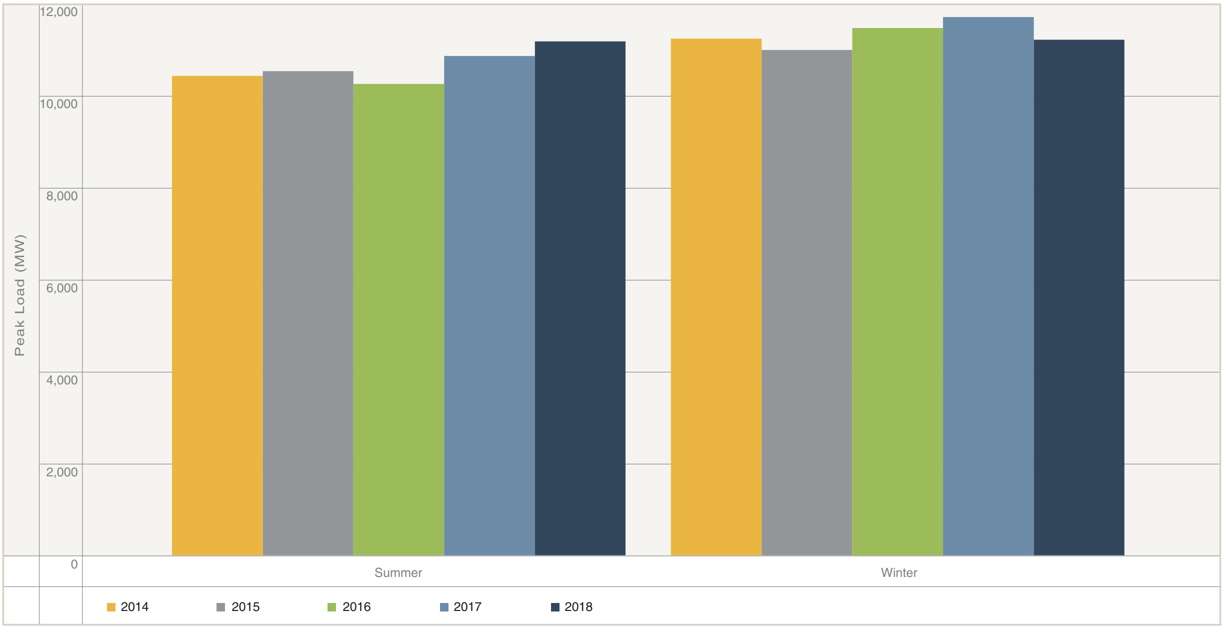
FIGURE 6: Daily peak load and average temperature



Seasonal peaks in Alberta load are usually set during periods of extreme temperatures: summer peaks are usually driven by heat; winter peaks are usually driven by cold. In 2018, high summer temperatures in Alberta led to a new all-time summer peak load: summer load peaked at 11,169 MW on August 10, three per cent above the 2017 summer peak of 10,852 MW.

The effect of temperature on load is clearly evident in the difference between the two winter periods that fell in the 2018 calendar year. Extremely cold temperatures in winter 2017/2018 spurred heating demand and pushed the seasonal load to a new all-time winter peak of 11,697 MW on January 11, 2018. Milder temperatures in December and November of Winter 2018/2019 limited Alberta load: the highest level reached was 11,205 MW on December 2, 2018.

FIGURE 7: Seasonal peak load

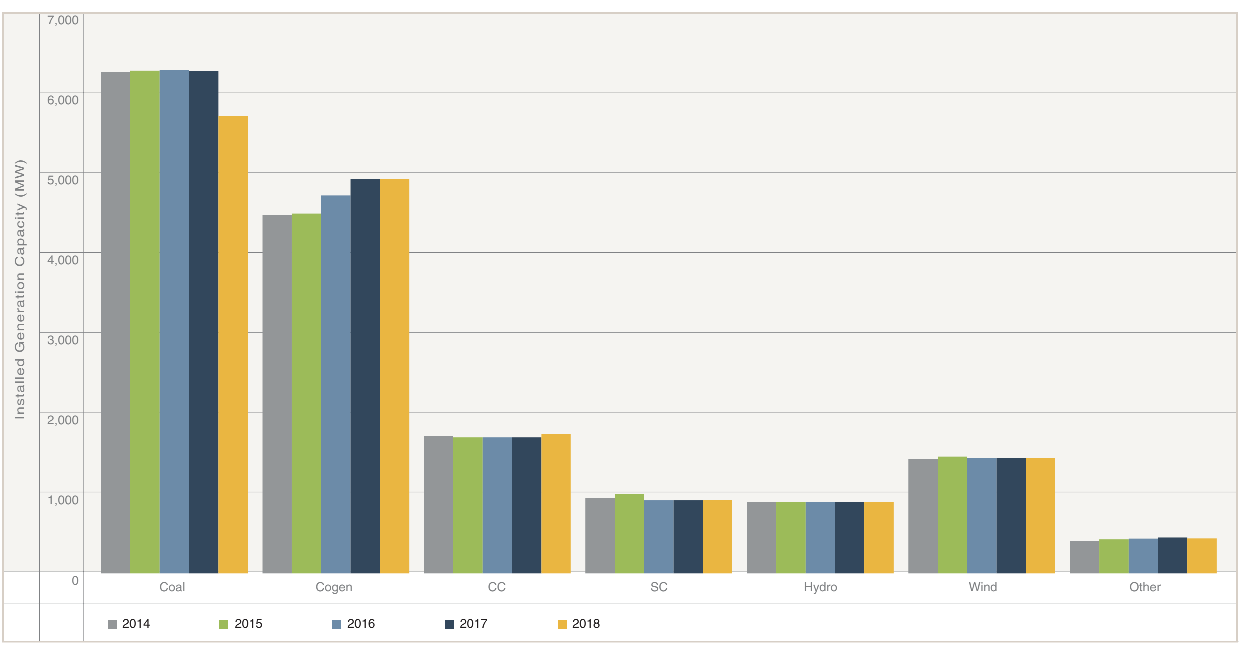


Installed generation

Total generation capacity decreased

The total installed generation capacity in Alberta decreased three per cent to 16,106 MW in 2018. This decrease was mostly due to the retirement of Sundance 1 and 2 coal units which removed 560 MW of installed generation from the fleet. An addition of 45 MW of combined-cycle generation also occurred over the past year. Figure 8 shows the annual installed capacity at the end of each calendar year.

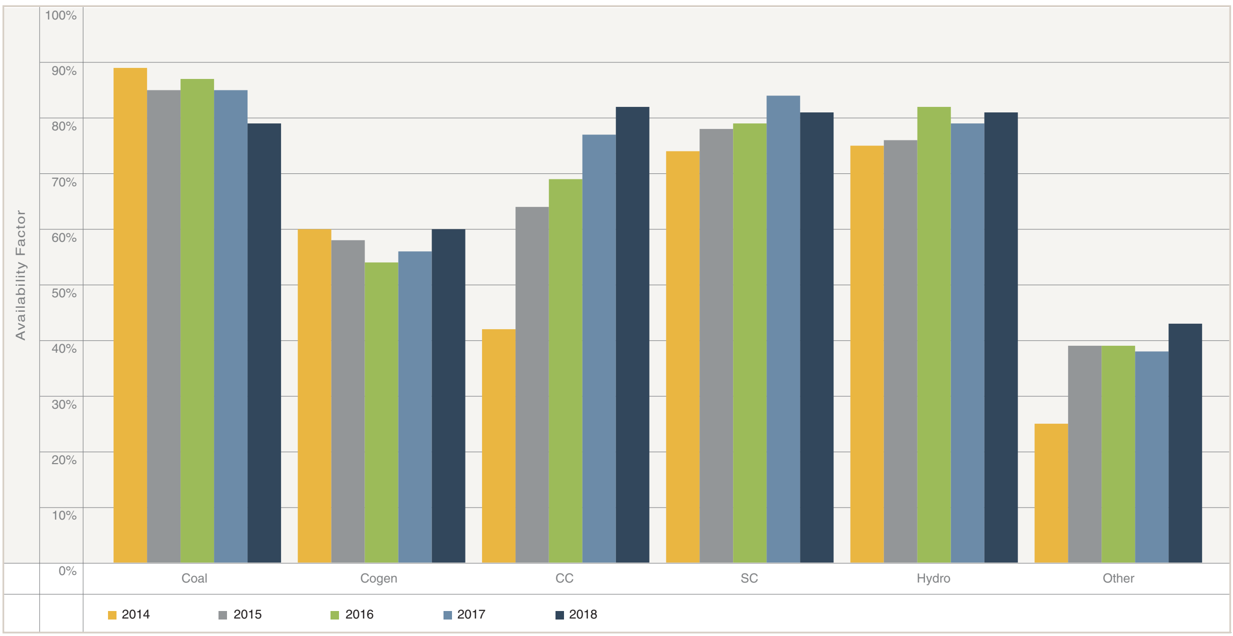
FIGURE 8: Annual generation capacity by technology



Generation availability

The availability factor represents the percentage of installed generation capacity that was available for dispatch into the energy or ancillary services markets. The availability factor is calculated as the ratio of the available capability to the installed generation capacity. Wind generation is excluded from this calculation since the availability of wind power depends on environmental factors. Figure 9 illustrates the annual availability factor by generation technology. Availability of coal generation has decreased from 2017 levels due to mothball outages of Sundance 3 and 5.

FIGURE 9: Annual availability factor by technology



Most available combined-cycle power dispatched

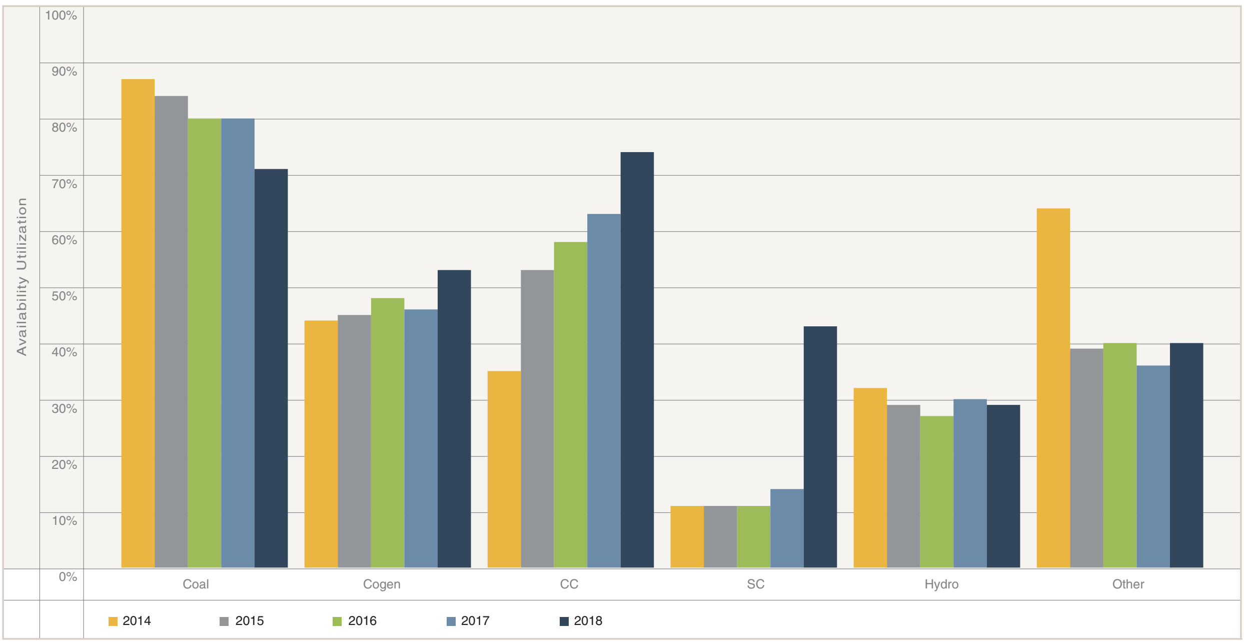
Availability utilization represents the percentage of the available power that was dispatched to serve system load. Availability utilization is calculated as the ratio of net-to-grid generation to the available capability. Figure 10 illustrates the annual availability utilization by generation technology.

Over the five-year period between 2014 and 2017, the availability utilization of coal generation was consistently highest among dispatchable generation technologies. In 2018, combined-cycle gas generation replaced coal generation as the most utilized generation technology. This can be attributed to the higher costs of coal generation due to the carbon tax and relatively cheaper gas generation costs in 2018.

The availability of cogeneration gas is less than those of other thermal generation. This relationship exists because cogeneration gas is used mainly as on-site generation at industrial facilities to serve behind-the-fence load. The power used to serve behind-the-fence load is excluded from the calculation of availability utilization. This quantity includes only the energy delivered to the AIES; as a result, the availability utilization measure may underestimate the reliability of cogeneration gas technology.

Over the period of 2014 to 2017, the availability utilization of simple-cycle gas was consistently lowest across dispatchable generation technologies. Simple-cycle gas generation tends to offer its energy to the market at higher prices than competing generation technologies. This offer behaviour tends to limit simple-cycle gas generation to peak system loads when pool prices are high and all lower-priced generation in the merit order has already been dispatched. However, in 2018, due to multiple reasons, the availability utilization of simple-cycle gas generation increased by 29 per cent compared to 2017. In 2018, the carbon tax increase coupled with the decrease in the price of gas, made gas generation cheaper relative to coal and therefore more utilized. Furthermore, the retirement and mothball outages of the coal plants also increased the frequency of high pool price hours, and with it, simple-cycle gas utilization.

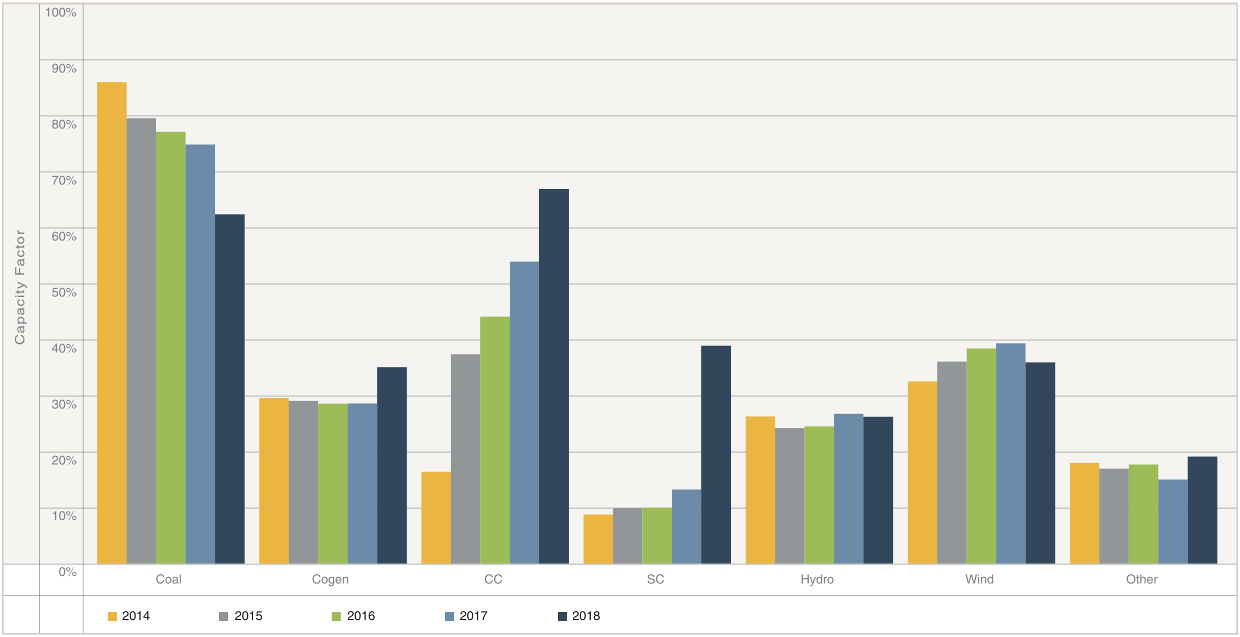
FIGURE 10: Annual availability utilization factor by technology



Combined-cycle generation capacity factor exceeds coal

Capacity factor represents the percentage of installed capacity used to generate electricity that was delivered to the grid. Capacity factor is calculated as the ratio of net-to-grid generation to the maximum capability. This calculation is equivalent to the product of the availability factor and availability utilization for dispatchable generation technologies; however, capacity factor can also be calculated for wind generation. Figure 11 illustrates the annual capacity factor by generation technology.

FIGURE 11: Annual capacity factor by technology



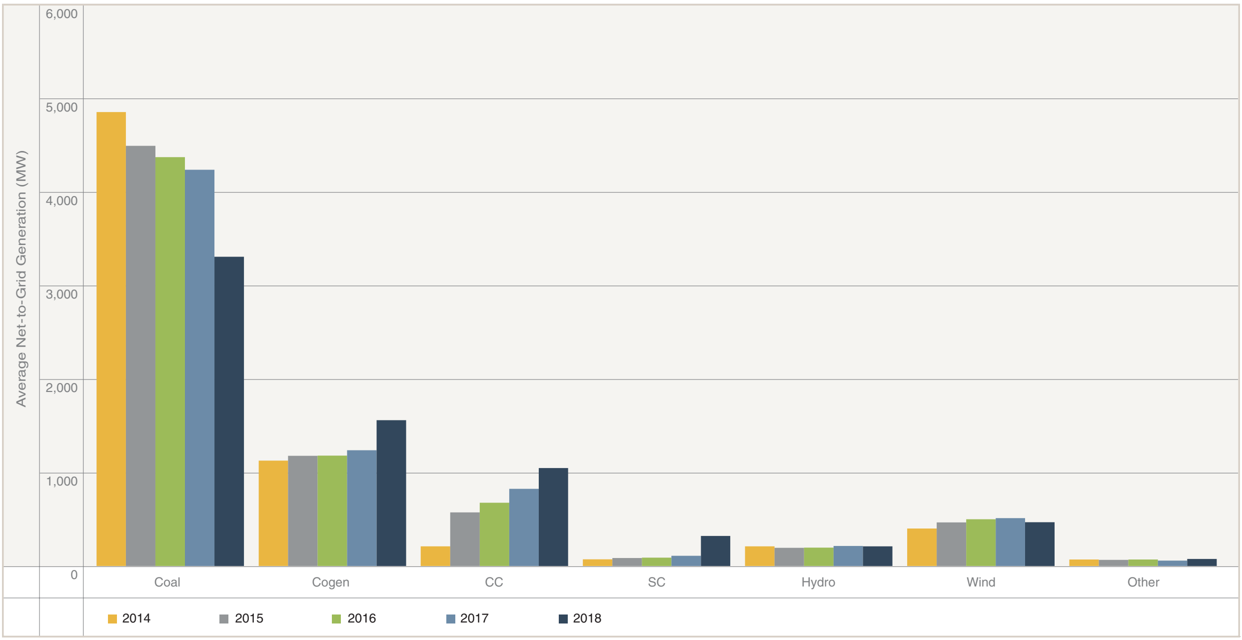
Over the four-year period between 2014 and 2017, the capacity factor of coal generation was consistently higher than the capacity factor of any other generation technology. On the other hand, the capacity factor of combined-cycle has been increasing since 2014 and it exceeded that of coal in 2018. The capacity factor of combined-cycle was 60 per cent—on average, for every 100 MW of installed capacity, combined-cycle generation delivered 60 MW to the AIES each hour. This result is consistent with the baseload operation of combined-cycle generation technology and implies an increase in combined-cycle share in baseload generation.

Over the same period of 2014 to 2017, the capacity factor of simple-cycle gas generation was consistently lowest among generation technologies. However, in 2018, the capacity factor of simple-cycle gas generation increased 23 per cent. This is a result of the increase in the cost of coal generation due to the carbon tax, as well as the decrease in gas prices in 2018. These changes made gas generation cheaper than coal generation, and therefore more gas generation was dispatched from the merit order.

Gas generation supplied 42 per cent of net-to-grid energy

Figure 12 illustrates the total net-to-grid generation from each generation technology over the last five years. In 2018, coal generation supplied 47 per cent of the energy delivered to the AIES. Gas generation technologies delivered 42 per cent of net-to-grid generation—a 12 per cent increase from 2017. Renewable generation provided the remaining 11 per cent, same as 2017. Wind generation provided the majority of energy from renewable sources: seven per cent of total net-to-grid generation was provided by wind power. The remaining four per cent was provided by a combination of hydro and other renewable generation.

FIGURE 12: Annual average net-to-grid generation by technology



Simple-cycle gas and hydro realized highest achieved premium to pool price

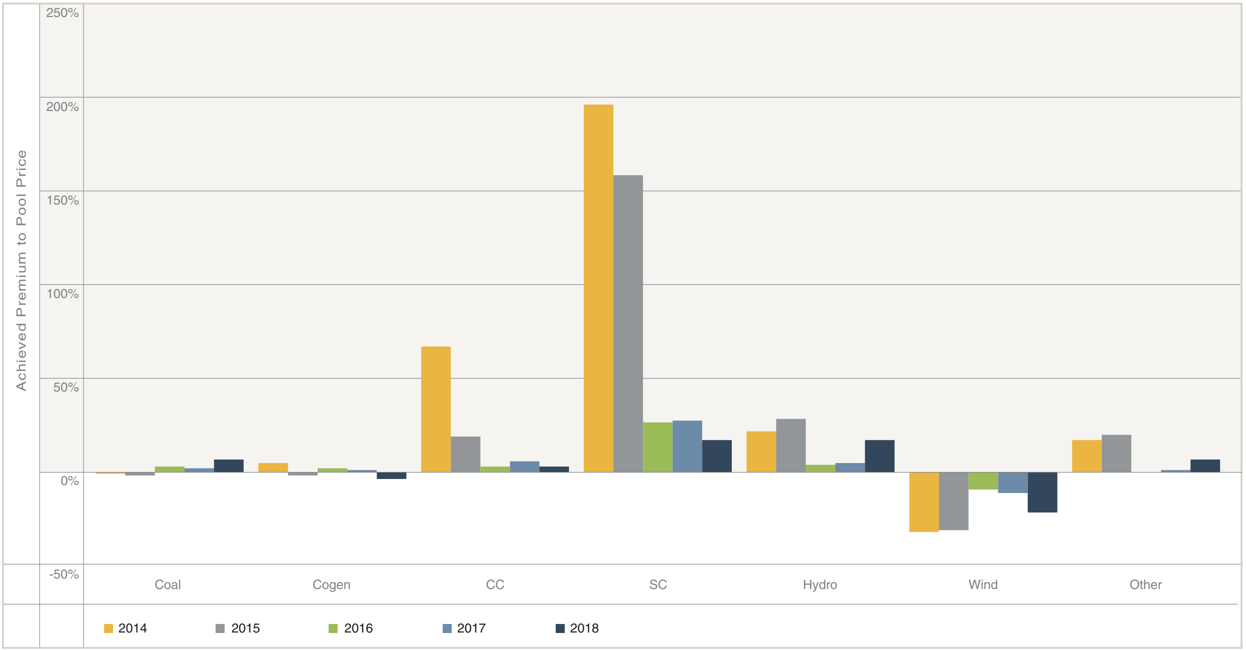
Achieved price represents the average price realized in the wholesale energy market for electricity delivered to the grid. Achieved price is calculated as the weighted average of hourly pool price, where the price in each settlement interval is weighted by the net-to-grid generation. The achieved margin represents the difference between the achieved price and the average pool price.

The achieved premium to pool price is calculated as the ratio of the achieved margin to the average pool price. An achieved premium of zero indicates that the achieved price is equal to the average pool price. An achieved premium of 100 per cent indicates that the achieved price is double the average pool price. An achieved discount of 50 per cent (that is, an achieved premium of negative 50 per cent) indicates that the achieved price is half the average pool price.

The achieved premium to pool price reflects the effect of offer behaviour on the average revenue per unit of energy delivered to the grid. Generation technologies that operate at a constant level regardless of pool price would realize achieved premiums around zero. Generation technologies that restrict operation to higher-priced hours would realize positive achieved premiums to pool price. Generation technologies that operate in lower-priced hours would realize negative achieved premiums to pool price.

Figure 13 illustrates the achieved premium to pool price realized by each generation technology over the past five years. Note that starting in 2016, both premiums and discounts to pool price were significantly muted from those in previous years. Operational characteristics of generation technologies inform offer behaviour, which influences the achieved price; however, sustained low price volatility in recent years limited the effect of offer behaviour on achieved price. As a result, the differences between the achieved premiums realized by different generation technologies were less pronounced than those observed in previous years. In 2018, both simple-cycle and hydro achieved the highest premium to pool price of 18 per cent.

FIGURE 13: Annual achieved premium to pool price on generated energy



The offer price of power dictates its position in the merit order, which determines whether system controllers will dispatch the unit to run. Market participants choose offer prices based on the operational characteristics of the unit, the price of fuel, and other considerations of the unit operator. Baseload generation technologies typically adopt a price-taker strategy: they offer energy to the market at a low price and produce energy in the majority of hours. Peaking generation technologies adopt a scarcity-pricing strategy: they offer energy at a higher price and only produce energy when strong demand drives pool price higher. The combination of offer strategy and market conditions determines the achieved price that each asset type receives.

Optimally, baseload generation technologies operate throughout the entire day. These baseload technologies include coal, cogeneration and combined-cycle. For coal and combined-cycle generation, it is more economical to continue operating through low-priced hours than to incur the high costs associated with halting and restarting generation. Most cogeneration facilities generate electricity as a byproduct of industrial processes that operate around the clock independent of the price of electricity.

Baseload generation generally offers its energy into the market at low prices. This price-taker strategy ensures that baseload generation is usually dispatched to run at a relatively constant level over time, and realizes an achieved price close to the average pool price. In 2018, coal and combined cycle technologies realized seven and three per cent premiums to pool price, and cogeneration gas technology achieved a four per cent discount to the pool price.

Peaking generation technologies achieve greater operational flexibility than baseload generation, but at higher cost. The combustion turbines used in simple-cycle gas generation can halt and restart operation without incurring high costs, but cost more to operate. These higher costs are reflected in higher offer prices, which positions peaking generation capacity late in the merit order.

Peaking generation will typically be dispatched to run during periods of high demand after lower-priced generation has been completely dispatched. Peaking generation operates in fewer hours than baseload generation but achieves higher average revenue. Over the period of 2014 to 2017, simple-cycle gas generation achieved the highest premium across all generation technologies in Alberta. In 2018, both simple-cycle and hydro generation realized the highest premiums to pool price. Simple cycle received an 18 per cent premium to pool price—a decrease of 12 per cent compared to its value in 2017. Hydro also received an 18 per cent premium to pool price, which was 13 per cent higher than its value in 2017.

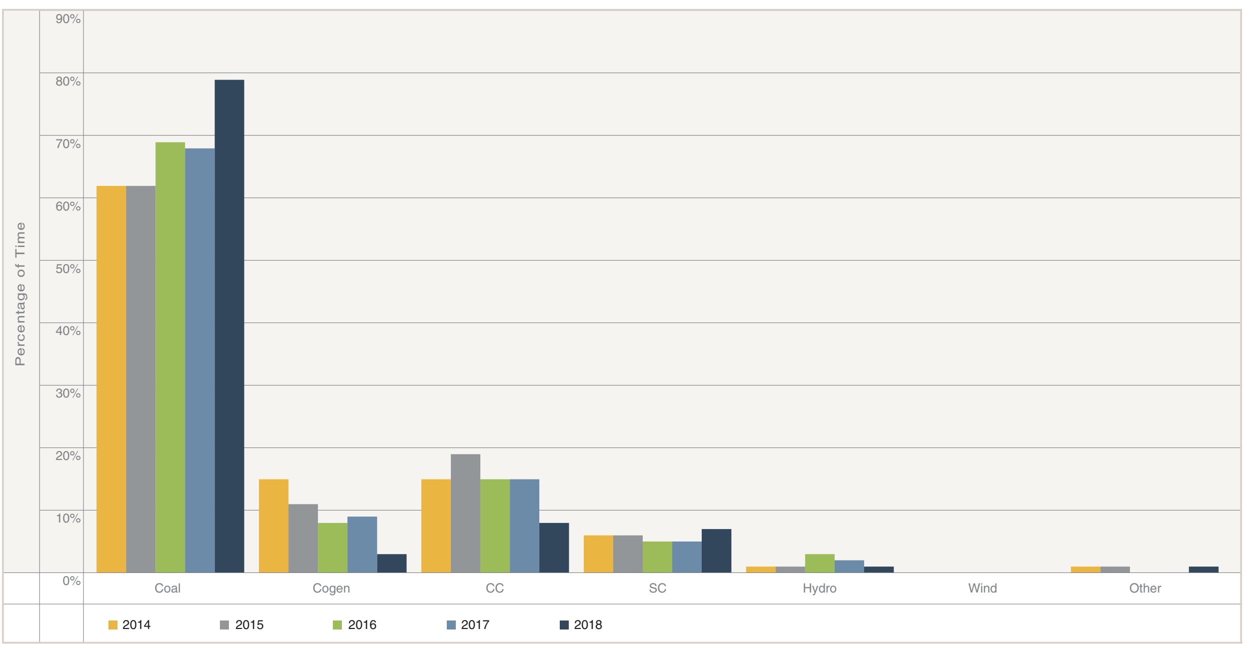
Wind generation is the only technology that consistently achieved a discount to pool price—that is, the achieved premium is consistently negative. This discount occurs due to fuel availability variations and geographic concentration. Wind power cannot control its operational schedule; the availability of wind power varies according to environmental conditions that are largely beyond human control.

When wind blows in a region, all in-merit wind generation in that region is delivered to the AIES. Wind generation in Alberta remains heavily concentrated in the southern region. When wind blows in southern Alberta, wind energy replaces some quantity of power from the energy market merit order. Wind generation tends to reduce the system marginal price, which lowers its achieved price. In 2018, wind generation received a 23 per cent discount to pool price.

Coal generation sets marginal price in 79 per cent of hours

Figure 14 illustrates how frequently each generation technology sets the system marginal price. Over each of the last five years, coal generation was the most common marginal price-setting technology. This prominence is consistent with the baseload operation of coal generation technology. Because coal assets would incur high costs by halting and restarting operation, they tend to operate in both on-peak and off-peak hours. In 2018, coal generation set the system marginal price 81 per cent of the on-peak hours and 75 per cent of the off-peak hours.

FIGURE 14: Annual marginal price-setting technology



Supply adequacy

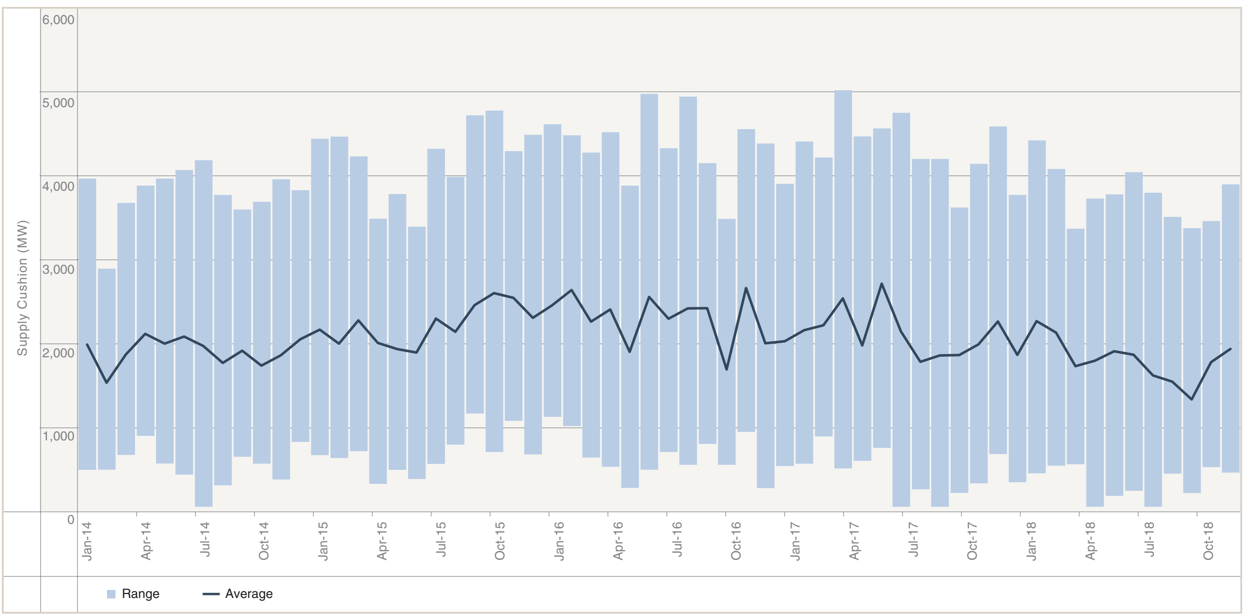
Supply adequacy expresses the ability of the system to serve demand. In general, supply adequacy increases as generation capability increases, and decreases as system load increases. This report evaluates supply adequacy using two common measures: supply cushion and reserve margin. An in-depth analysis of future supply adequacy is provided on the AESO website in the quarterly *Long-Term Adequacy Metrics* report.

Supply cushion decreased 15 per cent

The hourly supply cushion represents the additional energy in the merit order that remains available for dispatch after system load is served. Large supply cushions indicate greater reliability because more energy remains available to respond to unplanned outages. Over 2018, the average supply cushion decreased 15 per cent to 1,840 MW. This decrease occurred as a result of coal retirements, mothball outages, and an increase in the average AIL. Figure 15 shows the monthly supply cushion over the past five years.

Supply shortfall conditions arise when the supply cushion is zero. When the supply cushion falls to zero, all available power in the merit order has been dispatched to run, and system controllers may be required to take emergency action to ensure system stability. In 2018, supply shortfall conditions occurred twice. The first event was an 87-minute interval on May 14 which resulted in declaring an Energy Emergency Alert (EEA) 1. The second occurrence was a 92-minute interval on August 9 that led to an EEA1 alert followed by EEA2. Both EEA events were successfully resolved.

FIGURE 15: Monthly supply cushion



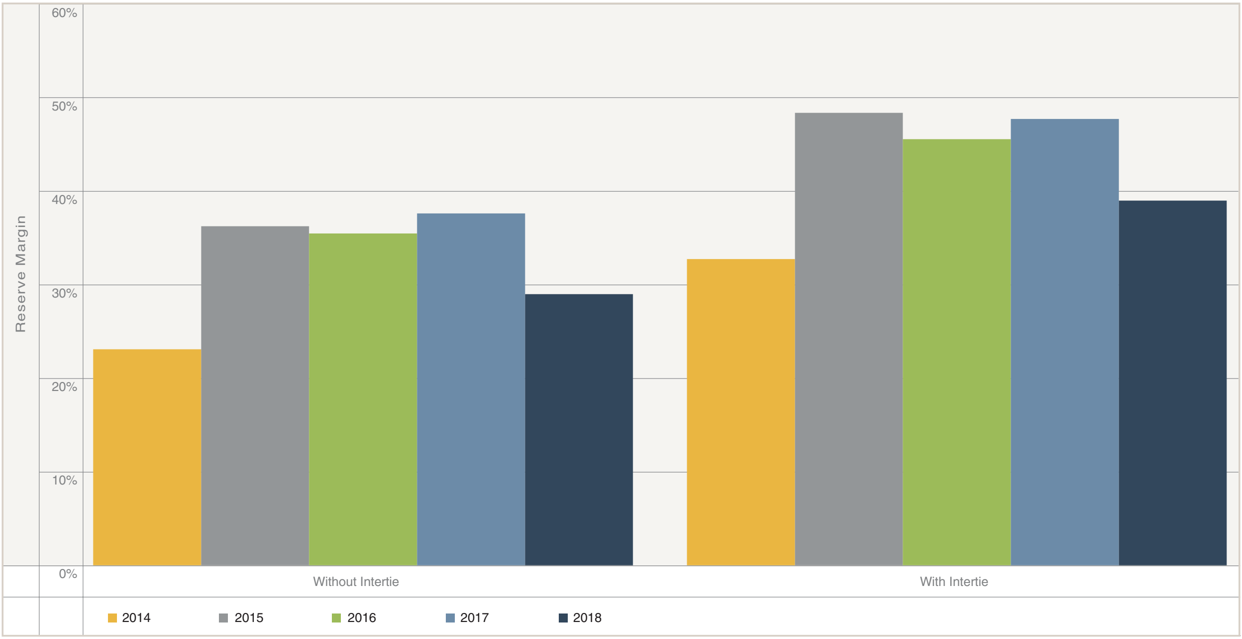
Reserve margin decreased nine per cent

Reserve margin represents the system generation capability in excess of that required to serve peak system load. The annual reserve margin is calculated both including and excluding the combined import capacity of interties in order to evaluate system reliance on generation outside Alberta. In this calculation, the system generation capability excludes wind generation, which may be unavailable, and reduces hydro generation to reflect seasonal variability.

Generation capability reflects extended unit outages and the commissioning dates of new generation. Reserve margin calculations in 2014 excluded the Shepard combined-cycle gas generation plant and the cogeneration plants at Nabiye and Kearl, which started commercial operations in 2015.

Figure 16 shows the annual reserve margin over the past five years. The fairly large decrease in the reserve margin from 2017 to 2018 is due to the decrease in installed generation after retirement of Sundance units 1 and 2 and an increase in the system peak load.

FIGURE 16: Annual reserve margin



Imports and exports

Alberta transfers electric energy across interties with three neighbouring control areas: British Columbia, Montana and Saskatchewan. Before 2013, imports and exports only flowed between Alberta and the two neighbouring Canadian provinces. The Montana—Alberta Tie Line (MATL) started commercial operation in September 2013. This new intertie permits Alberta to transfer energy directly across the border with the United States.

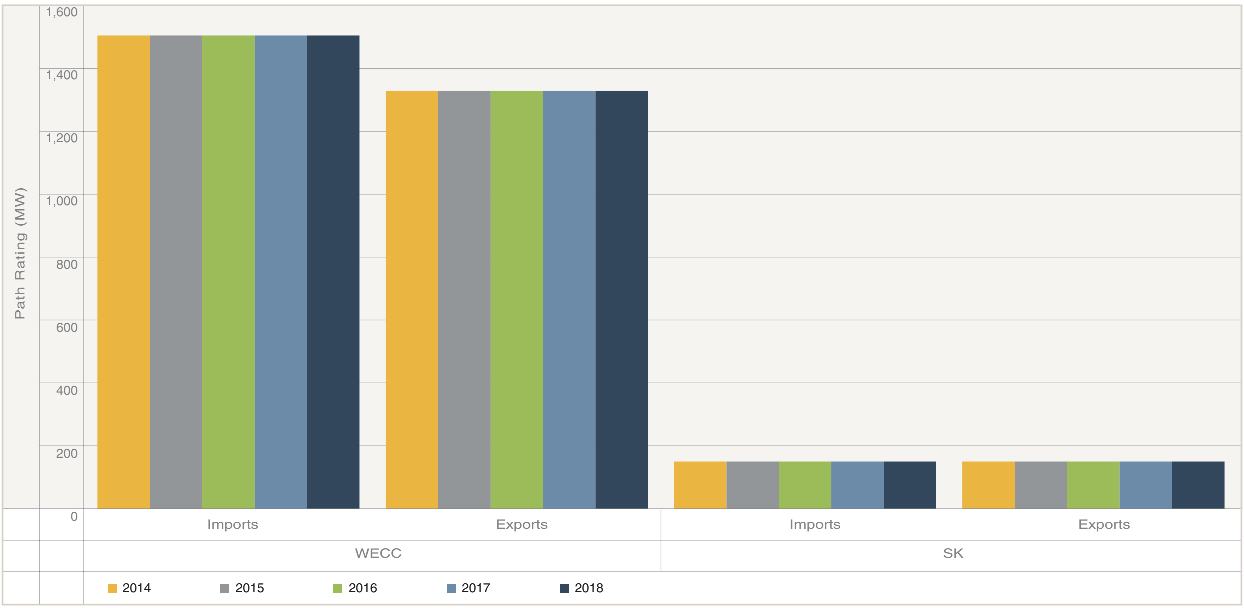
Transfer path rating remained stable

The transfer path rating establishes the physical capacity for the power that can flow across defined paths, and is estimated based on the physical properties of the line.

Alberta, British Columbia and Montana are members of the Western Electricity Coordinating Council (WECC) region; Saskatchewan is not. The total power that can flow between Alberta and other members of the WECC region is expressed as the combined path rating, calculated as the sum of the path ratings of the two individual interties.

Figure 17 shows the path rating at the end of each calendar year between Alberta and other WECC members, and between Alberta and Saskatchewan. Path ratings remained unchanged between 2017 and 2018.

FIGURE 17: Annual path rating by transfer path

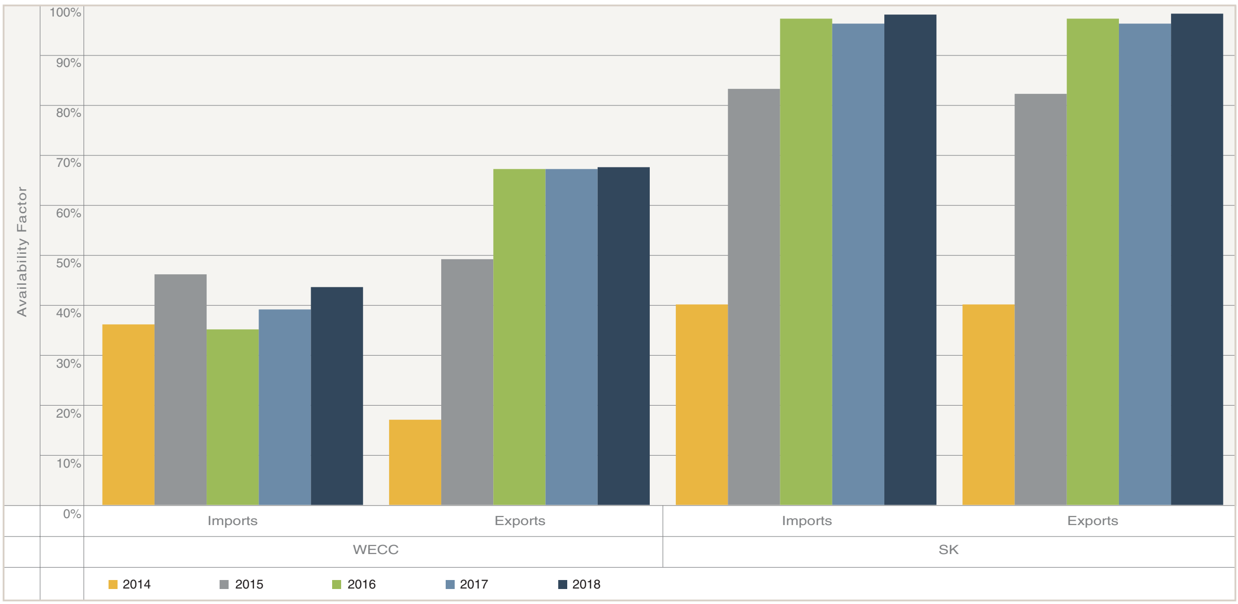


Intertie availability factor

System reliability standards define the criteria that determine the energy that can be transferred between jurisdictions. These standards impose three limits on transfers between control areas. The available transfer capability (ATC) limits imports and exports on an individual transfer path to reflect operational conditions and maintain the transmission reliability margin (TRM). The combined operating limit further restricts the transfer capability of total energy transfers between Alberta and other WECC members. The system operating limit specifies the maximum import and export capability between Alberta and all neighbouring jurisdictions.

The availability factor represents the percentage of the physical limit that was available to transfer energy between jurisdictions and is calculated as the ratio of the ATC to the path rating. Figure 18 illustrates the annual availability factor for transfers between Alberta and other regions. In 2015, updated system studies increased the combined operating limit that governed energy transfers between Alberta and other WECC members. In 2018, the availability of all transfer paths increased for both imports and exports.

FIGURE 18: Annual availability factor by transfer path



Import activity increases significantly

Availability utilization represents the percentage of available transfer capability that was used to transfer energy between jurisdictions. Availability utilization is calculated as the ratio of transferred energy to the ATC of the transfer path. Figure 19 illustrates the annual availability utilization for energy transfers between Alberta and other WECC members, and between Alberta and Saskatchewan. In 2018, import utilization increased from 2017 levels between Alberta and the WECC and Saskatchewan transfer paths, while export utilization decreased along both paths. A relatively wet year in the Pacific Northwest and higher prices in Alberta were main drivers for the changes in the import activity.

FIGURE 19: Annual availability utilization by transfer path

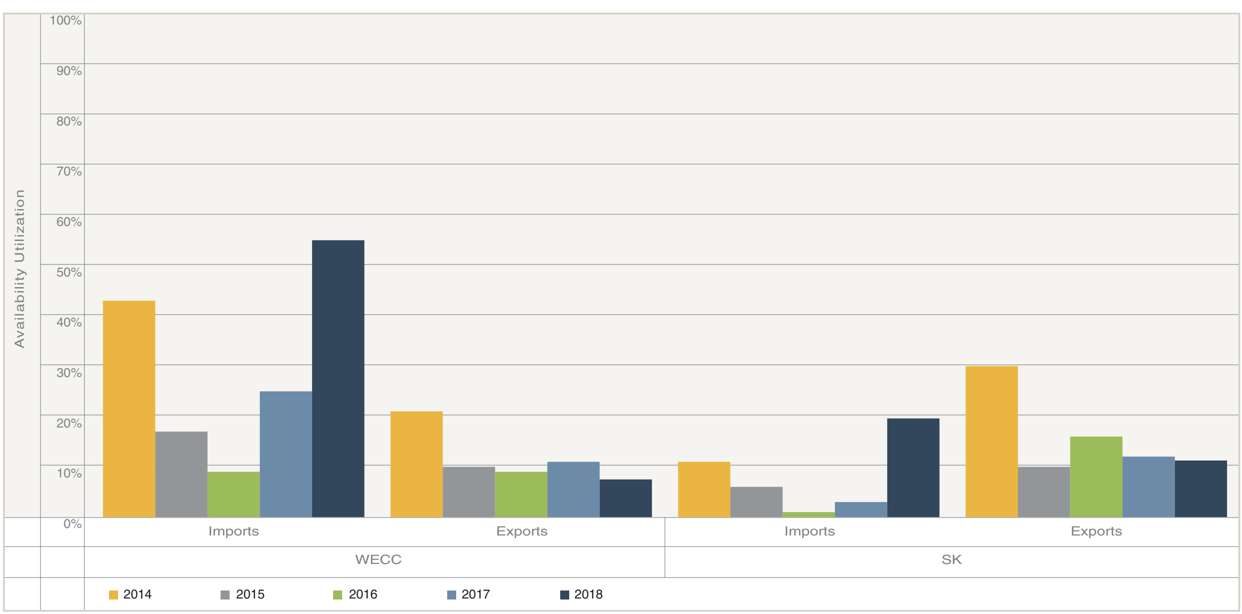


Figure 20 shows the annual interchange utilization between Alberta and the WECC regions over the past five years. Interchange utilization represents the ratio of net imports across the intertie to its transfer capability. Net imports include the volume of operating reserve procured on the intertie. The utilization calculation reflects the limits of the interties with British Columbia and Montana, the combined operating limits, and the Alberta system operating limit. Over 2018, Alberta imported energy from the WECC region in 70 per cent of hours, and exported energy in 20 per cent of hours.

FIGURE 20: Annual interchange utilization with WECC region

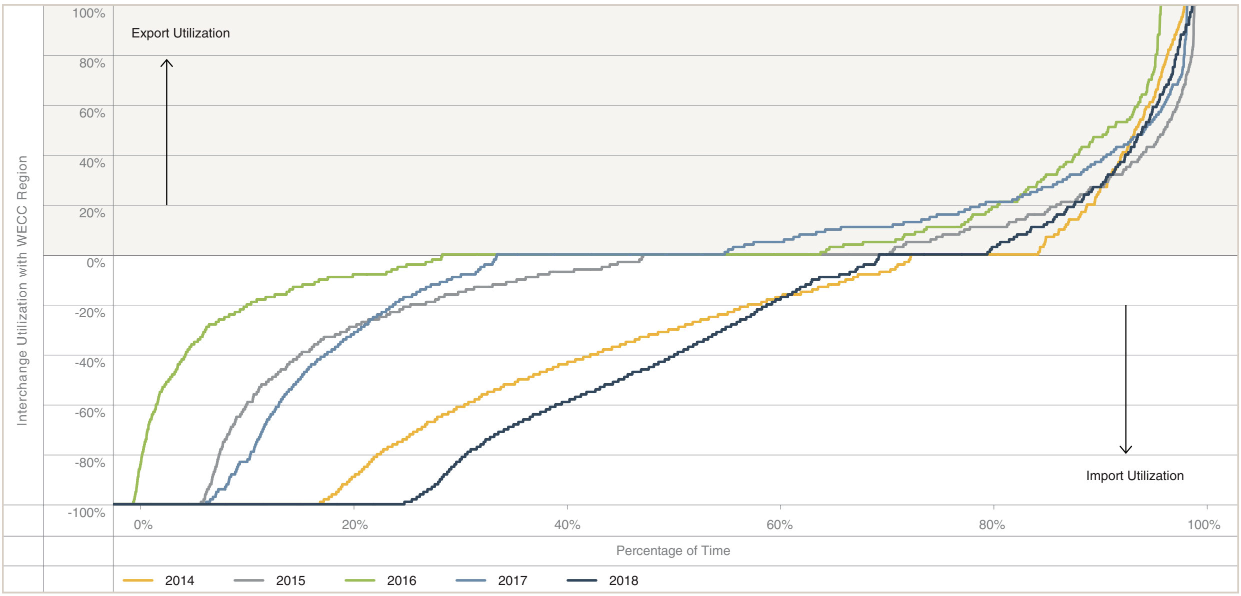
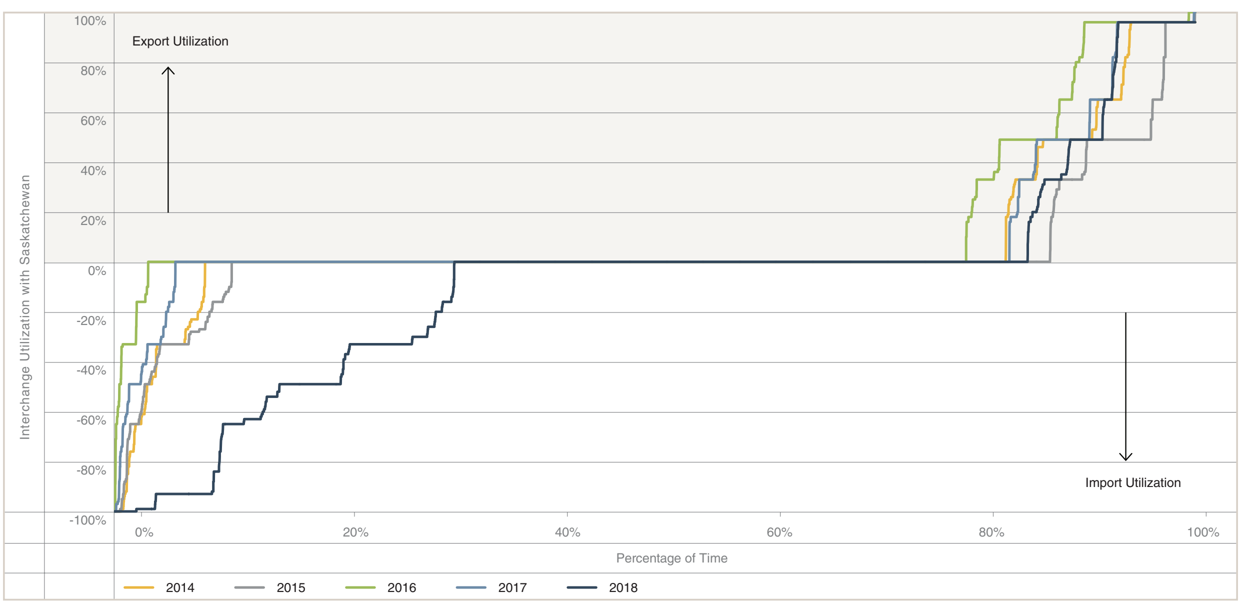


Figure 21 shows the annual interchange utilization between Alberta and Saskatchewan over the past five years. In 2018, Alberta imported energy from Saskatchewan in 31 per cent of hours, and exported energy in 15 per cent of hours.

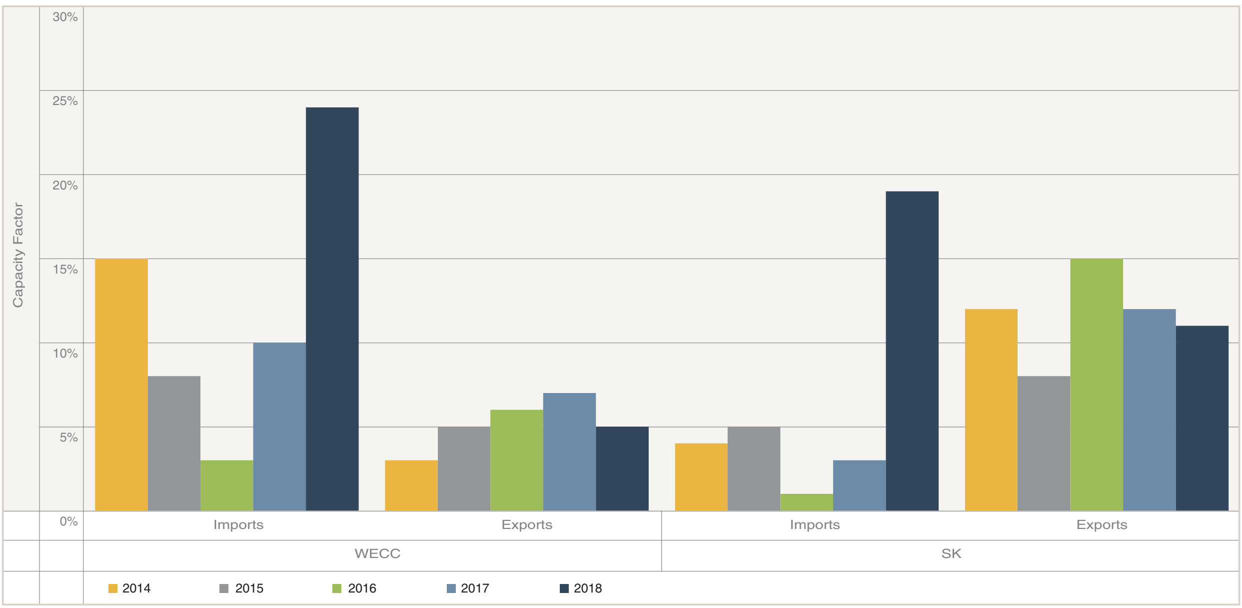
FIGURE 21: Annual interchange utilization with Saskatchewan



Capacity factor reflects significant increase in net imports

Capacity factor represents the percentage of the physical transfer capacity that was used to transfer energy between jurisdictions. The capacity factor is calculated as the ratio of total transferred energy to the path rating. This calculation is equivalent to the product of the availability factor and the availability utilization. Figure 22 illustrates the annual capacity factor for transfers between Alberta and other WECC members and between Alberta and Saskatchewan.

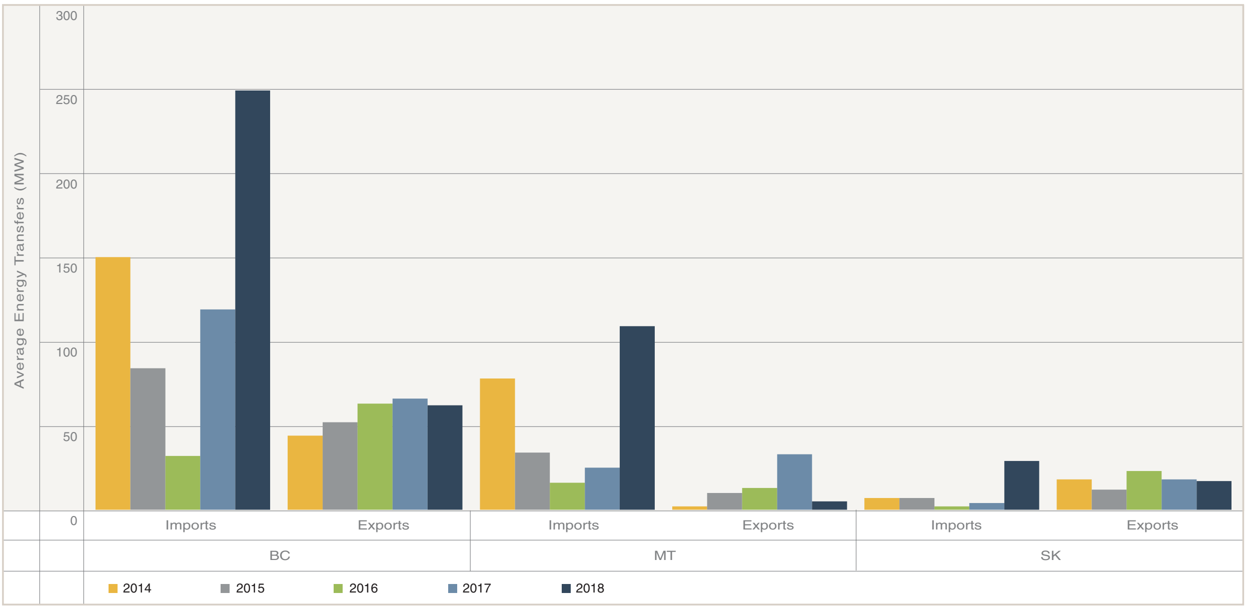
FIGURE 22: Annual capacity factor by transfer path



Alberta was a net importer

Figure 23 illustrates the annual average energy transferred from each province or state. In 2018, Alberta was a net importer. Relatively high electricity prices in Alberta encouraged imports into Alberta and consequently increased the net imports significantly compared to the 2017 levels. The last time that Alberta exceeded this level of imports was in 2012.

FIGURE 23: Annual intertie transfers by province or state

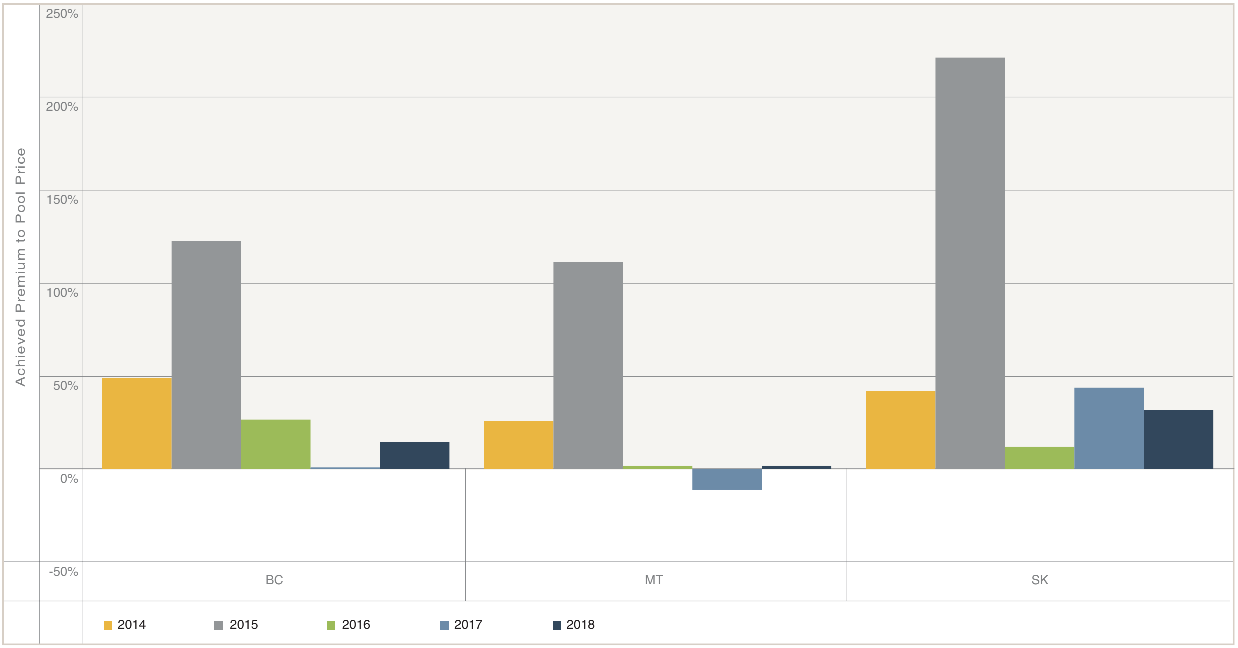


Achieved premium to pool price

Figure 24 illustrates the achieved premium to pool price on imported energy by province or state. Imported energy exerts downward pressure on pool price. All imports are priced at $0/MWh. As a result, imported energy displaces power from the merit order, and reduces the system marginal price. Market participants earn a profit by importing energy into Alberta only when the pool price—after the effect of imports—exceeds their costs.

High pool price volatility in 2018 increased profit opportunities for importers and the achieved premium to pool price on imported energy increased for British Columbia and Montana. The achieved premium ranged between two and 17 per cent.

FIGURE 24: Annual achieved premium to pool price on imported energy



Wind generation

Wind generation served five per cent of Alberta Internal Load

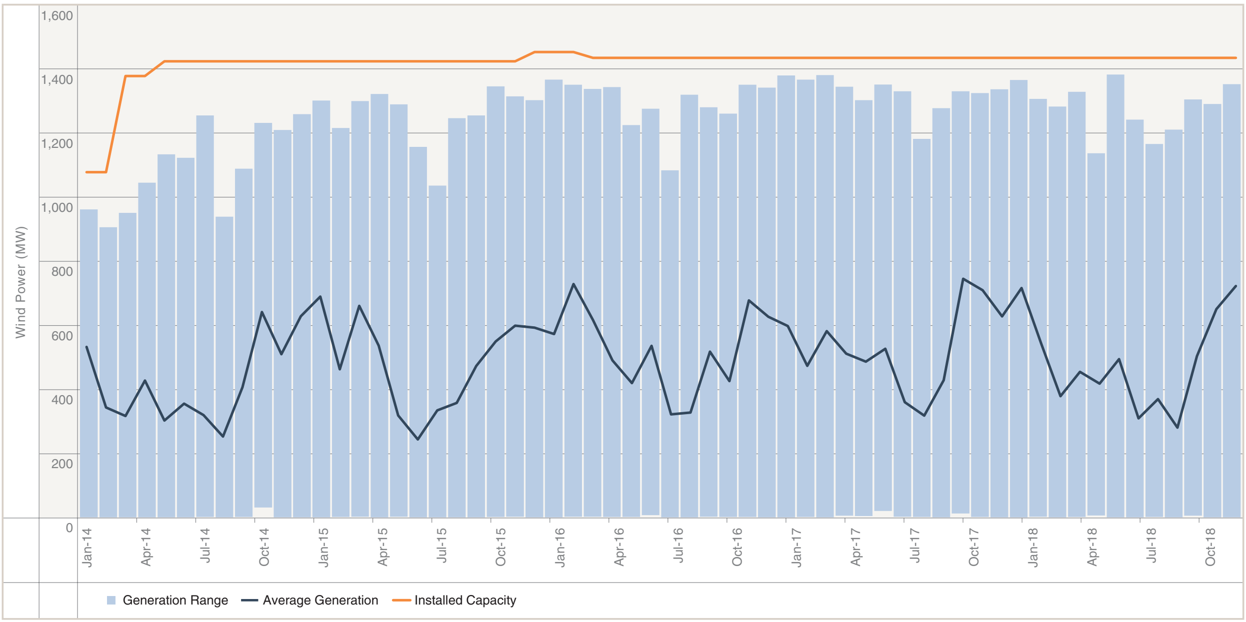
Table 3 summarizes the annual statistics for wind generation. Over 2018, installed wind generation capability remained unchanged from 2017. At the end of the year, wind farms made up nine per cent of the total installed generation capacity in Alberta. Wind generation produced seven per cent of Alberta's net-to-grid generation and served five per cent of total AIL in 2018.

TABLE 3: Annual wind generation statistics

Year	2014	2015	2016	2017	2018
Installed wind capacity at year-end (MW)	1,434	1,463	1,445	1,445	**1,445**
Total wind generation (GWh)	3,519	4,089	4,402	4,486	**4,100**
Wind generation as a percentage of total AIL	4%	5%	6%	5%	**5%**
Average hourly capacity factor	30%	33%	35%	35%	**32%**
Maximum hourly capacity factor	88%	94%	93%	96%	**96%**
Wind capacity factor during annual peak AIL	3%	7%	15%	6%	**9%**

Figure 25 shows the installed wind generation capacity and monthly wind generation ranges. The monthly average of wind generation exhibits a pronounced seasonal pattern, peaking in winter and falling in summer. The majority of wind generation exhibits a weaker seasonal pattern. Strong winds may occur in any month, though they occur more frequently in winter.

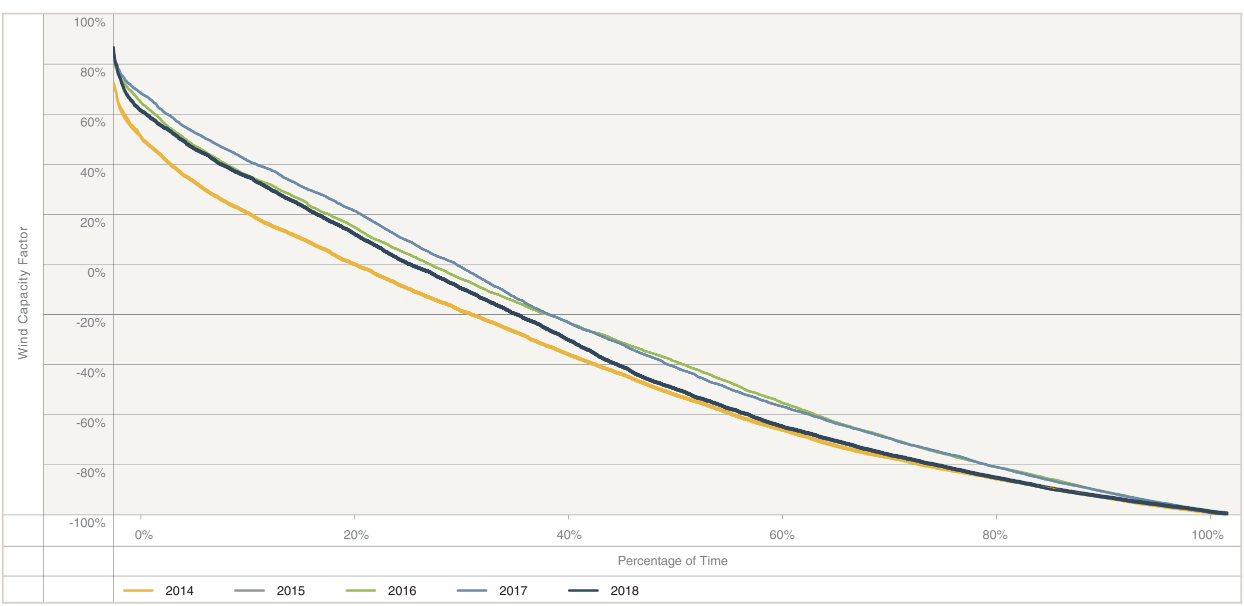
FIGURE 25: Monthly wind capacity and generation



Wind capacity factor decreased

Figure 26 illustrates annual duration curves for the hourly capacity factor for Alberta wind generation. Capacity factor represents the percentage of installed capacity used to generate energy that is delivered to the AIES. The duration represents the percentage of time that the capacity factor of wind generation equals or exceeds a specific value.

FIGURE 26: Annual wind capacity factor duration curves



The duration curves for the capacity factor of wind generation decreased in 2018 compared to its levels in 2017. The capacity factor of wind generation averaged 32 per cent over 2018, showing a three per cent decrease from 2017. For every 100 MW of installed wind capacity, wind power generated an average of 32 MW of energy each hour in 2018. The capacity factor—the ratio of net-to-grid generation to installed capacity—for wind generation is comparable to that of cogeneration and simple-cycle gas generation; however, unlike these technologies, wind generation depends largely on environmental factors; it cannot be dispatched to run when wind is unavailable.

Regional wind

Wind generation in the province was located exclusively in southern Alberta until early 2011. Since 2011, the addition of five wind facilities in central Alberta increased the geographic diversification of wind generation across the province. At the end of 2018, wind generation capacity totaled 1,096 MW in southern Alberta, and 349 MW in central Alberta. Increased geographic diversification of wind assets reduced the variability of total wind generation in the province.

Table 4 tabulates regional wind generation statistics over 2018. Although the average capacity factors of central and southern wind were at the same level in 2018, the achieved price for central wind slightly exceeded that of southern wind. For each megawatt of installed capacity, a wind farm in central Alberta generated the same amount of energy as a wind farm in southern Alberta, but for each unit of energy generated, a central wind farm earned slightly more revenue than a southern wind farm.

TABLE 4: 2018 regional wind statistics

Region	South	Central	Total
Installed wind capacity at year end (MW)	1,096	349	**1,445**
Total wind generation (GWh)	3,114	986	**4,100**
Average wind capacity factor	32%	32%	**32%**
Achieved price ($/MWh)	$38.32	$40.73	**$38.90**

Ancillary services

Cost of operating reserve increased

Operating reserve manages fluctuations in supply or demand on the AIES. Operating reserve is separated into two products: regulating reserve and contingency reserve. Regulating reserve uses automatic generation control to match supply and demand in real time. Contingency reserve maintains the balance of supply and demand when an unexpected system event occurs. Contingency reserve is further divided into two products: spinning reserve and supplemental reserve. Spinning reserve must be synchronized to the grid; supplemental reserve does not need to be. Alberta reliability standards require that spinning reserve provides at least half of the total contingency reserve.

Operating reserve is procured by the AESO on a day-ahead basis. For each of the three products of operating reserve, the AESO must procure two commodities: active and standby. Active reserve is used to maintain system reliability under normal operating conditions. Standby reserve provides additional reserve capability and is dispatched as required either after all active reserve has been dispatched, or when procured active reserve cannot be provided due to generator outage or transmission constraint.

The price of operating reserve is determined differently in the active and standby reserve markets. Participants in the active reserve market specify offer prices as premiums or discounts to the pool price. The AESO procures active operating reserve in ascending order of offer price until active operating reserve levels satisfy system reliability criteria. The equilibrium price of active reserve is the average of the marginal offer price and the bid ceiling established by the AESO. The clearing price of active reserve, paid to all dispatched active reserve, is the sum of this equilibrium price and the hourly pool price.

The standby reserve market involves two prices: the premium and the activation price. The premium grants the option to activate standby reserve. The standby market clears based on a blended price formula that takes into consideration the premium and activation price offered by each potential supplier. However, payment for cleared offers in the standby market is a pay-as-bid mechanism. The cleared offers are paid their specified premium price for the option, and if the AESO exercises this option and activates the standby reserve, the provider also receives the activation price.

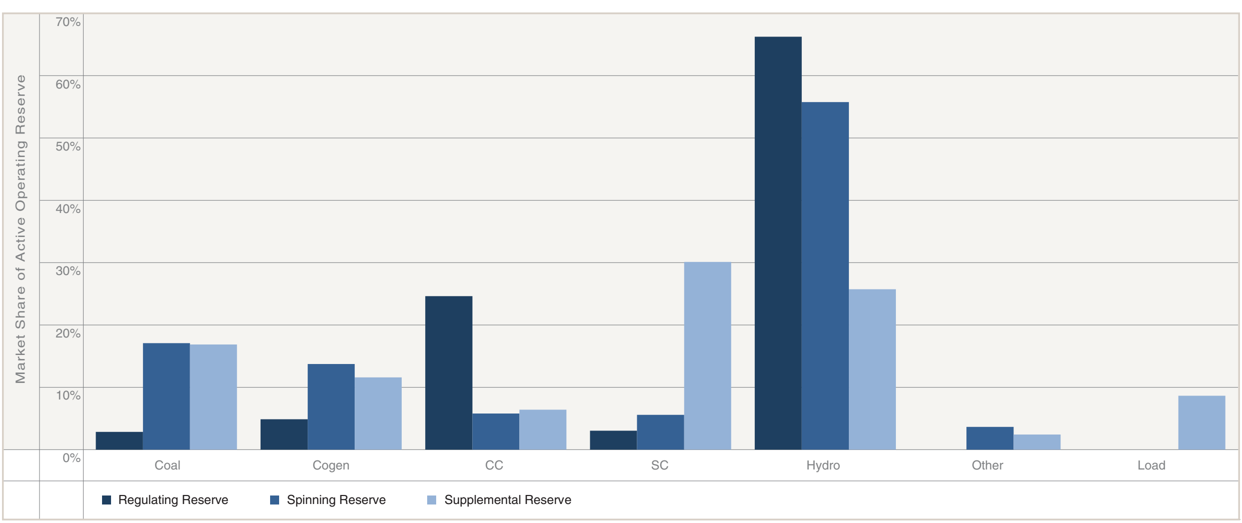
Table 5 summarizes the total cost of operating reserve over the past five years. The total cost of operating reserve in 2018 increased 196 per cent to $240 million, driven mostly by the effect of higher pool prices on the cost of active reserves and increased activation price of standby reserves.

TABLE 5: Annual operating reserve statistics

Year	2014	2015	2016	2017	2018
Volume *(GWh)*					
Active procured	6,006	5,333	5,262	5,449	**5,802**
Standby procured	2,142	2,140	2,049	2,058	**1,971**
Standby activated	65	136	85	236	**343**
Cost *($-millions)*					
Active procured	$168	$105	$53	$67	**$195**
Standby procured	$14	$13	$12	$8	**$8**
Standby activated	$3	$20	$2	$6	**$36**
Total	$185	$138	$67	$81	**$240**

Market share represents the percentage of total procured capacity that is provided as operating reserve by each generation technology. Figure 27 illustrates the annual market share of active operating reserve. In 2018, hydroelectric generation obtained a greater market share of all active operating reserve products than any other technology.

FIGURE 27: 2018 market share of active operating reserve



Transmission must-run and dispatch down service

The system controller issues Transmission Must-Run (TMR) dispatches in parts of the province's electricity system when transmission capacity is insufficient to support local demand. TMR dispatches command a generator in or near the affected area to operate at a specified generation level in order to maintain system reliability.

TMR dispatches effectively resolve transmission constraints, but also exert a secondary effect on the energy market. Energy dispatched under TMR service displaces marginal operating units from the merit order and lowers the pool price. This secondary effect interferes with the fair, efficient and openly competitive operation of the electricity market. In December 2007, the AESO introduced the Dispatch Down Service (DDS) to negate the downward effect of dispatched TMR energy, and reconstitute the pool price. DDS offsets the downward influence of TMR dispatches on pool price by removing dispatched in-merit energy from the merit order.

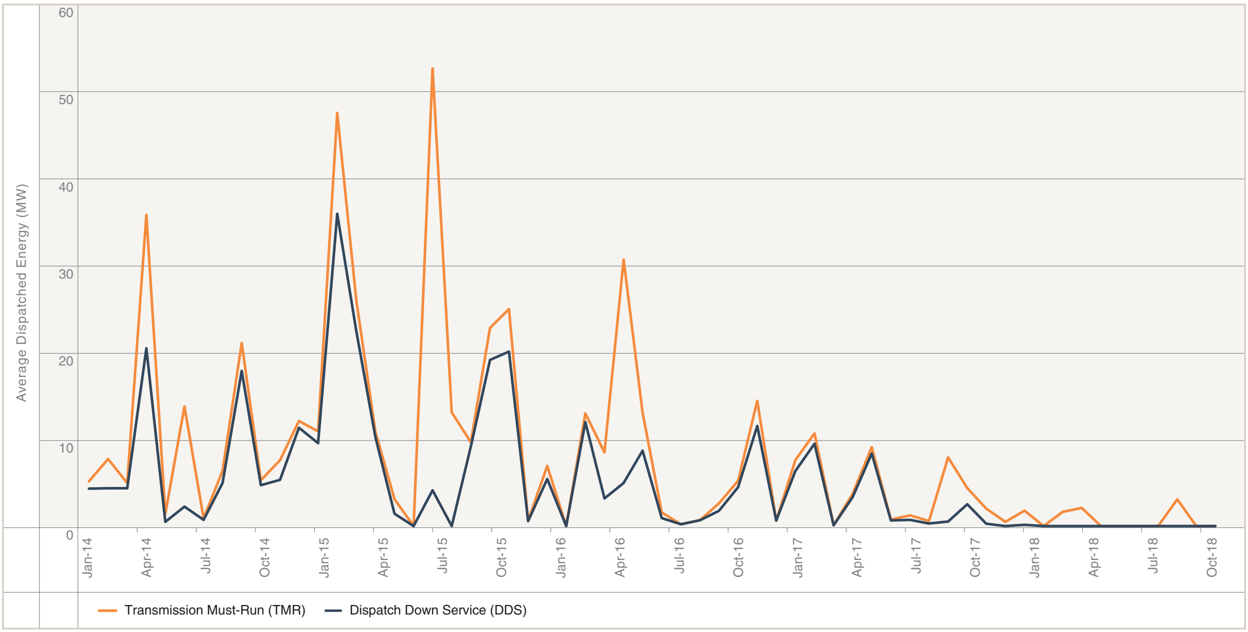
DDS requirements are limited to the amount of dispatched TMR. DDS cannot offset more energy than is dispatched under TMR service. In 2018, DDS offset one per cent of dispatched TMR volume. Table 6 summarizes the annual TMR and DDS statistics over the past five years. The total cost of DDS is allocated between energy suppliers in proportion to the volume of energy that they generated or imported. The dispatched TMR volumes showed a significant decrease compared to the previous years.

TABLE 6: Annual TMR and DDS statistics

Year	2014	2015	2016	2017	2018
Transmission Must-Run					
Dispatched energy (GWh)	88	161	71	35	7
Dispatch Down Service					
Total payments ($-millions)	$1.2	$1.6	$0.5	0.1	0.0
Dispatched energy (GWh)	59	95	39	24	0.1
Average charge ($/MWh)	$0.02	$0.02	$0.01	$0.00	$0.02

Figure 28 shows the monthly volumes of TMR and DDS dispatched over the past five years. System controllers issue TMR dispatches in response to transmission constraints on the AIES.

FIGURE 28: Monthly TMR and DDS dispatched energy



Uplift payments

All energy delivered to the AIES receives the same price, called the pool price. Uplift payments represent additional compensation paid to market participants for dispatched generation that was offered at a higher price than the pool price. Table 7 summarizes the cost of uplift payments over the past five years.

TABLE 7: Annual uplift payments

Year	2014	2015	2016	2017	2018
Payments to Suppliers on the Margin					
Average range ($/MWh)	7.54	5.99	1.08	2.35	**8.15**
Total payments ($-millions)	1.16	1.25	0.16	0.21	**1.32**
Transmission Constraint Rebalancing					
Constrained-down generation (GWh)			2.4	1.4	**3.0**
Total payments ($-millions)			0.01	0.02	**0.04**

Payments to suppliers on the margin increased

Payment to Suppliers on the Margin (PSM) is a settlement rule intended to address price discrepancies between dispatch and settlement intervals. The highest-priced offer block dispatched in each minute sets the system marginal price (SMP). At settlement, the hourly pool price is calculated as the simple average of SMP. When system controllers dispatch an offer block that is priced above the settled pool price, that offer block may qualify for compensation under the PSM rule.

The annual cost of PSM increased to $1.32 million in 2018, from $0.21 million in 2017. Hourly PSM is determined by the difference between the maximum SMP in a settlement period and the pool price. The annual average price range increased 247 per cent to $8.15/MWh in 2018.

Transmission constraint rebalancing payments

When the AESO dispatches up the energy market merit order in order to replace in-merit generation that has been curtailed due to a constraint, those generators with offers located above the unconstrained price are eligible to receive a Transmission Constraint Rebalancing (TCR) payment. The AESO IT system determines the energy production volume of each block of energy priced between the constrained system marginal price and the unconstrained system marginal price and multiplies that volume by the difference between the unconstrained pool price and the offer price associated with the megawatt level of energy provided by that eligible offer block in order to determine the amount of the transmission constraint rebalancing payment. In 2018, constraints on the transmission system required system controllers to curtail 3 GWh of in-merit energy and the TCR payments to market participants totaled $40,000.

Final notes

As the market evolves throughout 2019 and into the future, the AESO will continue to monitor, analyze and report on market outcomes. As part of this monitoring process, the AESO provides real-time, historical and forecast reports and metrics on the market. These include daily and weekly reports outlining energy and operating reserve market statistics and a broad selection of historical datasets. Reports are produced with the best information available at the time, and will change as more information becomes available. The AESO encourages stakeholders to send any comments or questions on this report, or any other market analysis questions to **market.analysis@aeso.ca**
We appreciate your input.

Alberta Electric System Operator

2500, 330-5th Avenue SW
Calgary, AB T2P 0L4
Phone: 403-539-2450
www.aeso.ca

03/19