AESO 2017
Annual Market Statistics

MARCH 2018

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 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 2017, 201 participants in the Alberta wholesale electricity market transacted approximately $3 billion of energy. The annual average pool price for wholesale electricity increased 21 per cent from its previous-year value to $22.19/MWh. The average natural gas price fell one per cent, averaging $2.05/GJ.

The average Alberta load in 2017 increased four per cent from 2016 levels as a consequence of general economic growth and the rebound from the Fort McMurray wildfires. Alberta load set new seasonal peak records in both summer and winter due to extreme weather conditions.

Price	2017	Year/Year Change
Pool price	$22.19/MWh	+21%
Gas price	$2.05/GJ	-1%
Spark spread @7.5 GJ/MWh	$6.82/MWh	+140%

Load	2017	Year/Year Change
Average AIL	9,426 MW	+4%
Winter peak	11,473 MW	+0%
Summer peak	10,852 MW	+6%

The installed generation capacity increased slightly in 2017 due to the energization of a new cogeneration gas asset at Fort Hills. The first large-scale solar generation asset in Alberta started commercial operation at Brooks; however, energy produced from coal generation continued to serve most Alberta load.

Alberta was a net importer of electricity in 2017. Imports to the province increased 196 per cent from 2016 levels, and exports increased by 18 per cent. Alberta was a net importer from British Columbia, but a net exporter to both Saskatchewan and Montana.

Price of electricity

Pool price increased 21 per cent

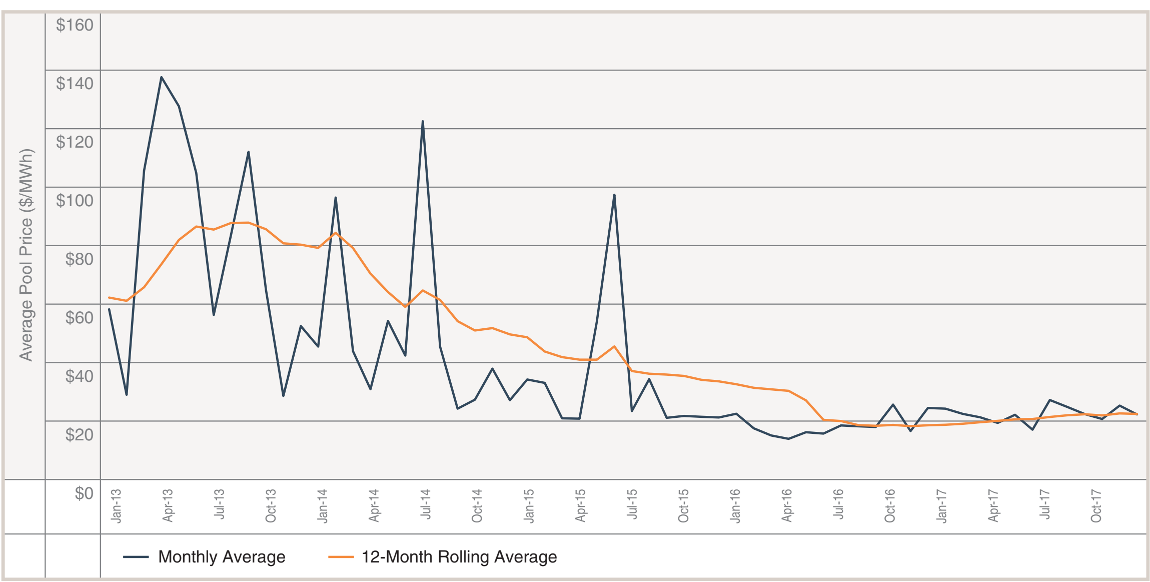
Pool price averaged $22.19/MWh over 2017—an increase of 21 per cent from 2016. This report separates each day into on-peak and off-peak periods: on-peak periods start at 7 a.m. and end at 11 p.m.; the remaining hours of the day make up the off-peak period. In 2017, the average pool price during the on-peak period increased 24 per cent to $24.46/MWh, and the off-peak average pool price increased 15 per cent to $17.64/MWh. However, 2017 was the second lowest price year in the past 10 years after 2016. Table 1 summarizes historical price statistics over the 10-year period between 2008 and 2017.

TABLE 1: Annual pool price statistics

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Pool price ($/MWh)										
Average	89.95	47.81	50.88	76.22	64.32	80.19	49.42	33.34	18.28	**22.19**
On-peak average	112.97	58.04	62.99	102.22	84.72	106.13	61.48	40.73	19.73	**24.46**
Off-peak average	43.92	27.36	26.67	24.22	23.51	28.29	25.28	18.55	15.37	**17.64**
Spark Spread ($/MWh)										
Average	32.0	19.6	22.5	50.4	47.3	57.6	17.6	14.1	2.8	**6.8**

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 2017, the monthly average pool price ranged from a low of $16.78/MWh in June to a high of $26.96/MWh in July. The 12-month rolling average shows that pool price remained stable and significantly below historical average levels.

FIGURE 1: Monthly average pool price



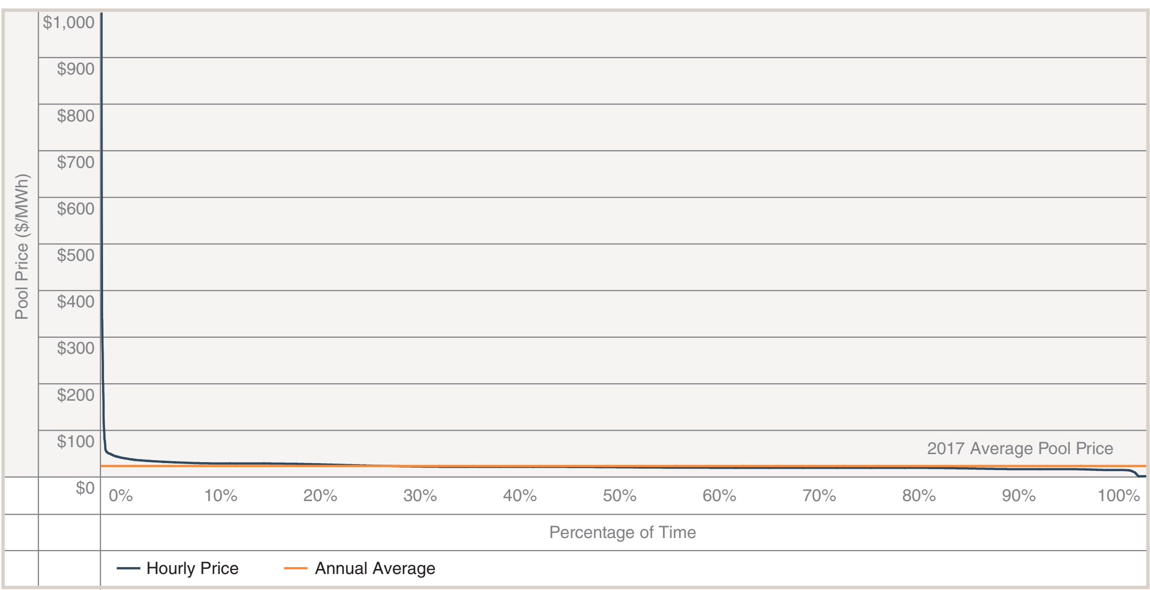
The hourly price of electricity in Alberta is determined according to the economic principles of supply and demand. Generators submit offers specifying the amount of power that they will provide in a one-hour settlement period and the price at which they are willing to supply it. This offer price can 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 2017 year. The hourly price of electricity exceeded the annual average in 28 per cent of hours, or approximately one hour of every four; however, because electricity was more expensive in these hours, they exerted a gentle upward influence on the average price.

FIGURE 2: 2017 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 47 hours in 2017: 38 hours in June, five hours in May, and four hours in April. All supply surplus events were successfully resolved by curtailing in-merit generation.

Spark spread increased 140 per cent

Spark spread measures the profitability of a natural gas baseload generation asset; a combined-cycle plant in this calculation. Positive spark spread implies that baseload operation would be profitable for gas-fired generators; negative spark spread implies that baseload operation would be unprofitable.

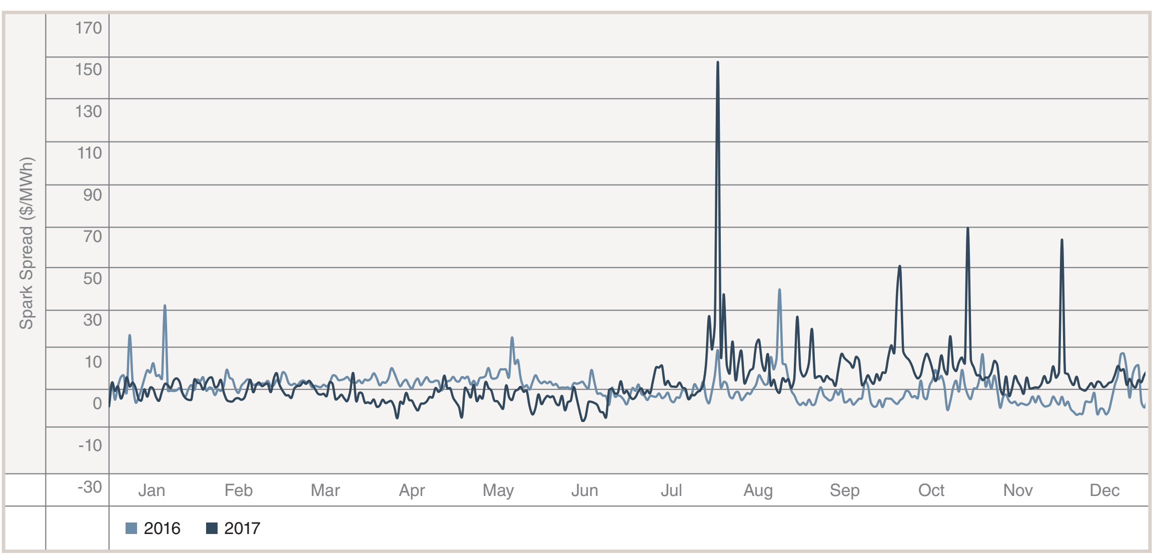
The hourly spark spread is the difference between the wholesale price of electricity and the cost of natural gas required to generate that electricity. The cost of fuel is calculated as the product of the operating heat rate and the unit cost of natural gas.

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.

Figure 3 shows the daily average spark spread for 2016 and 2017. In 2017, the annual average spark spread increased 140 per cent to $6.82/MWh. The increase in the spark spread is largely due to spikes in pool price and falling natural gas prices observed in the third and fourth quarters of 2017.

The market heat rate expresses the price of electricity in units of natural gas instead of dollars. When the market heat rate exceeds the operational heat rate of a gas-fired generation facility, the plant may earn money by operating; otherwise, it is cheaper to procure energy from the market. The fall in natural gas prices to negative prices invalidated the market heat rate calculation in 2017. For this reason, the market heat rate discussion has been removed from this report.

FIGURE 3: 2016 and 2017 daily average spark spreads



Alberta Internal Load

Average load grew four per cent

Table 2 summarizes annual demand statistics over the past 10 years. In 2017, average Alberta Internal Load (AIL) increased four per cent to 9,426 MW, and peak load set a new record at 11,473 MW. The increase in average load in 2017 was largely due to economic growth, load recovery of Fort McMurray and energization of projects such as Fort Hills and the North West Redwater Sturgeon refinery.

TABLE 2: Annual load statistics

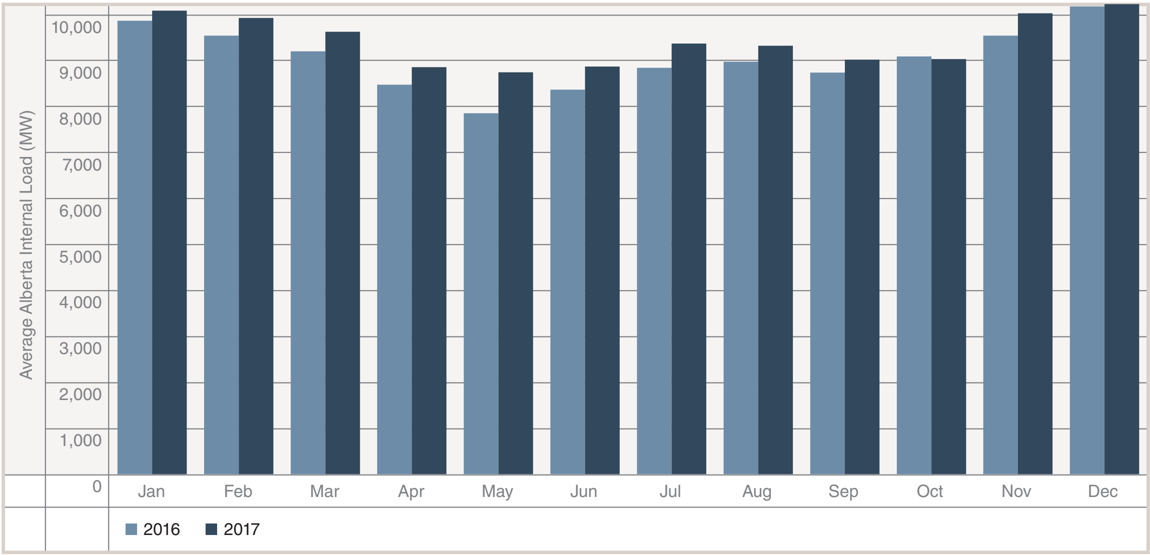
Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alberta Internal Load										
Total (GWh)	69,947	69,914	71,723	73,600	75,574	77,451	79,949	80,257	79,560	**82,572**
Average (MW)	7,963	7,981	8,188	8,402	8,604	8,841	9,127	9,162	9,057	**9,426**
Maximum (MW)	9,806	10,236	10,196	10,226	10,609	11,139	11,169	11,229	11,458	**11,473**
Minimum (MW)	6,411	6,454	6,641	6,459	6,828	6,991	7,162	7,203	6,595	**7,600**
Average growth	+0.1%	+0.2%	+2.6%	+2.6%	+2.4%	+2.8%	+3.2%	+0.4%	-0.9%	**+4.1%**
Load factor	81%	78%	80%	82%	81%	79%	82%	82%	79%	82%
System load										
Average (MW)	6,595	6,434	6,550	6,699	6,791	6,903	7,132	7,110	7,030	**7,220**

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: peak hourly load significantly exceeds the average load over the year. A high load factor indicates that load is relatively stable: 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.

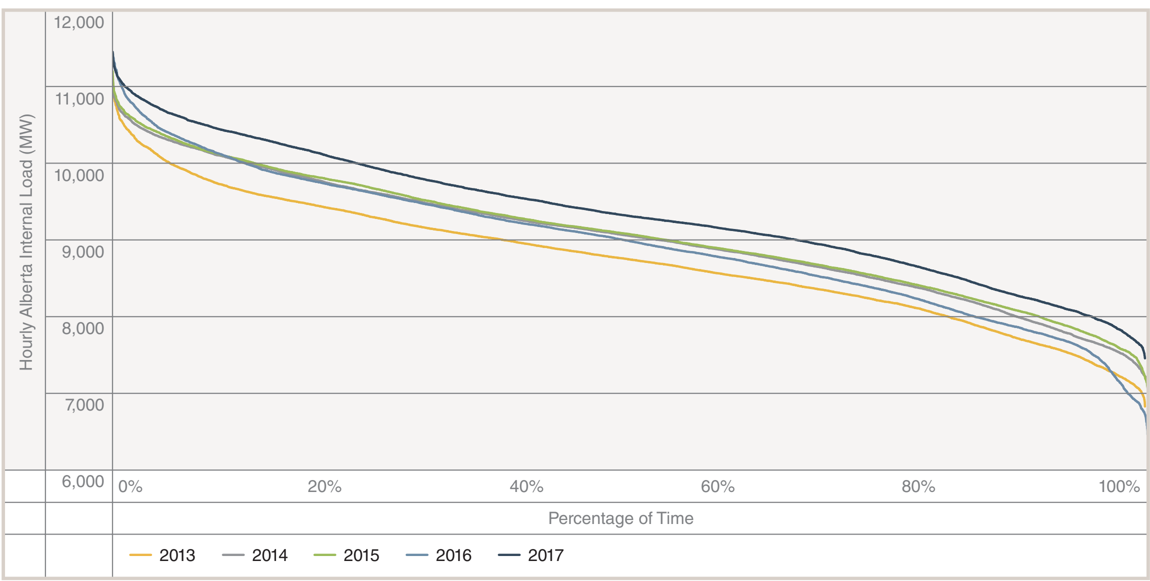
Figure 4 shows the monthly average load in 2016 and 2017. Load additions and extreme winter and summer temperatures in 2017 drove monthly load above the previous-year level. The large increase in average load observed in May is due to depressed load in 2016, due to the provincial state of emergency in response to fires in northeastern Alberta that forced the evacuation of Fort McMurray and nearby communities.

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 2017 increased only slightly over its previous-year value, hourly load in 2017 was higher than any previous year.

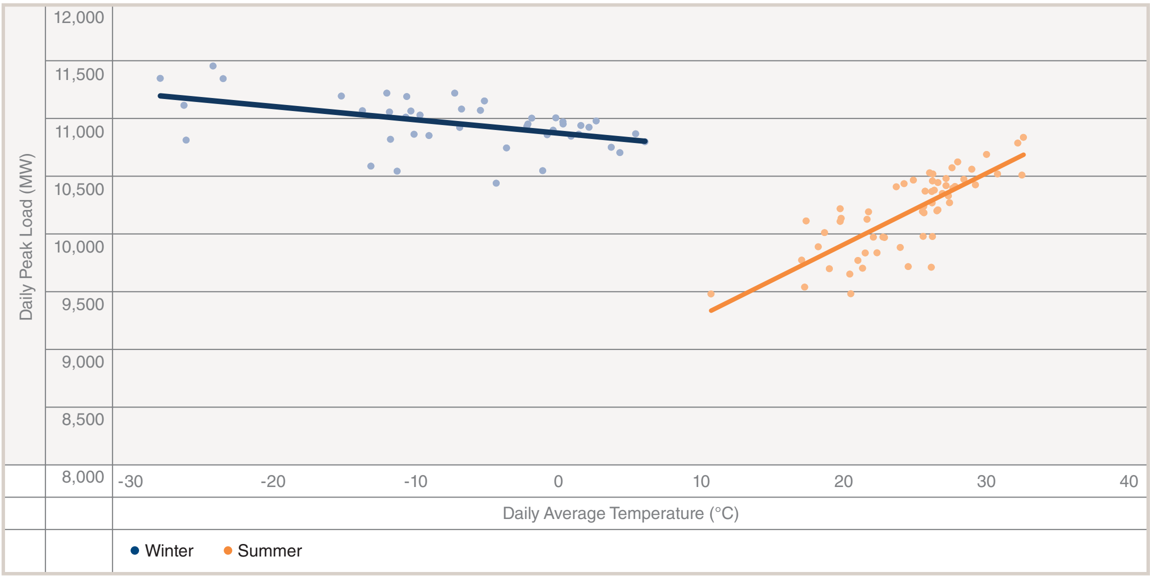
FIGURE 5: Annual load duration curves



Seasonal load set new peaks

Temperature exerts influence on load. Alberta internal load tends to increase as the temperature becomes more extreme. Figure 6 illustrates the relationship between temperature and daily peak demand in weekdays over 2017. On winter weekdays, a decrease of one degree Celsius increased peak load by an average of 12 MW. During summer weekdays, an increase of one degree Celsius increased peak load by an average of 64 MW.

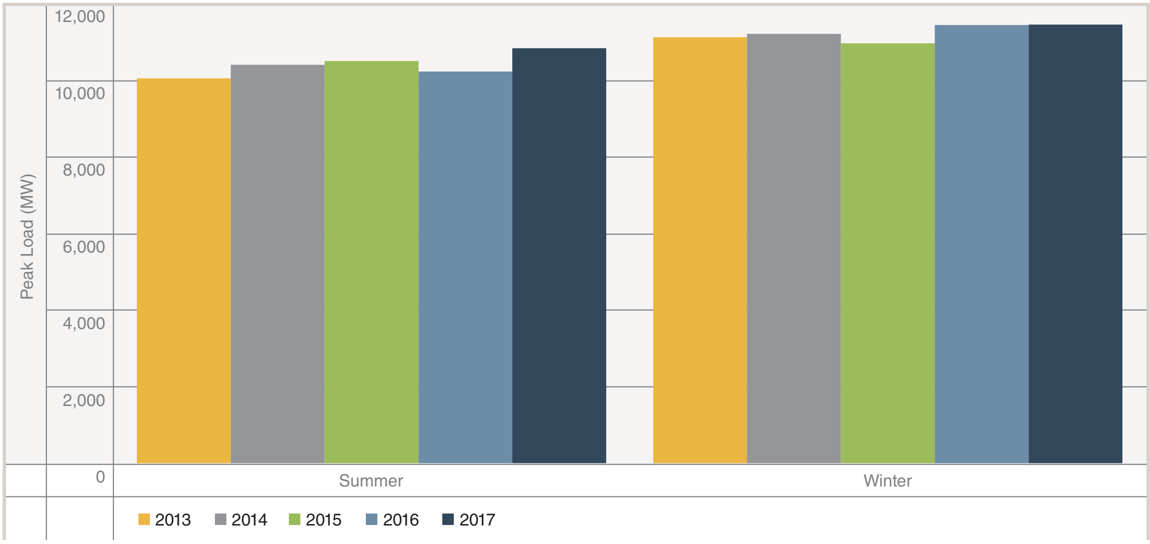
FIGURE 6: Daily peak load and average temperature



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. The summer season starts on May 1 and ends on Oct. 31. High summer temperatures in Alberta led to an increase in the summer peak load in 2017: summer load peaked at 10,852 MW on July 27, six per cent above the 2016 summer peak of 10,244 MW.

The winter season starts on Nov. 1 and ends on April 30 of the following calendar year. Cold temperatures drove winter load to new seasonal and overall peaks: winter load peaked at 11,473 MW on Dec. 28, only slightly higher than the 2016 winter peak of 11,458 MW. Figure 7 illustrates the winter and summer peak demand over the past five years.

FIGURE 7: Seasonal peak load

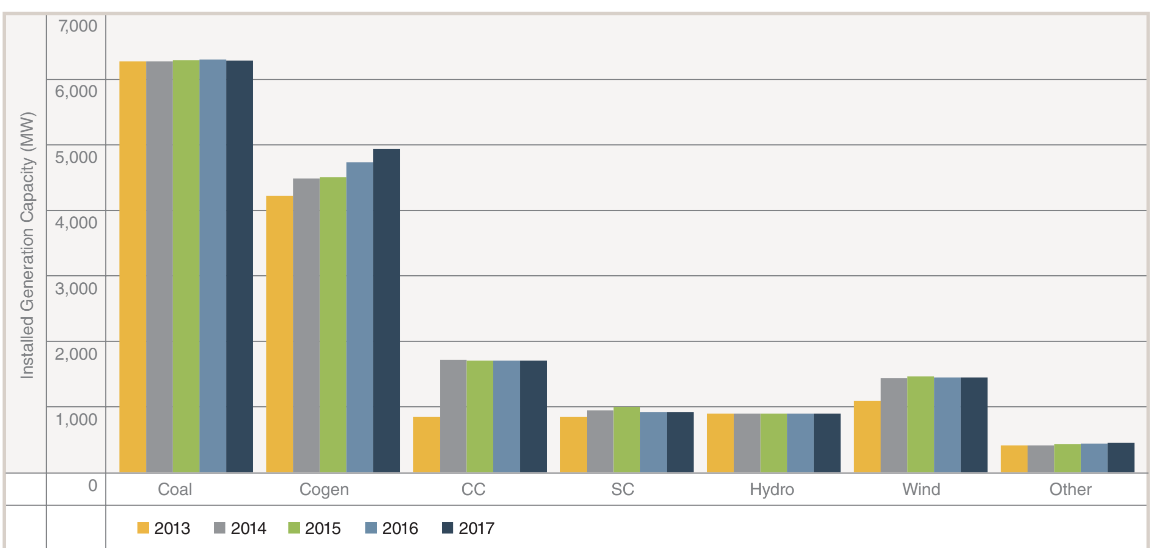


Installed generation

Total generation capacity increased slightly

The total installed generation capacity in Alberta increased slightly to 16,626 MW in 2017. Figure 8 shows the annual installed capacity at the end of each calendar year. The installed generation shows an end-of-year snapshot of the generation capacity. Although Sundance 1 retired at the last hour of the year, it was included in the generation capacity as it was in active operation during 2017. The energization of Fort Hills added 199 MW of cogeneration gas capacity, and Brooks Solar became the first large-scale solar generation asset in Alberta, adding 15 MW of solar capacity.

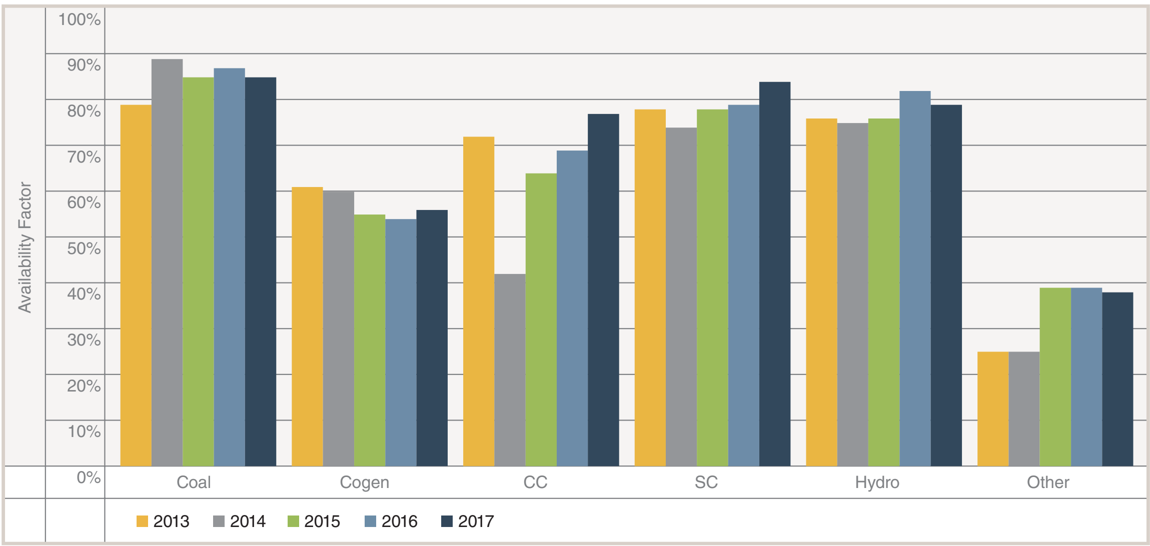
FIGURE 8: Annual generation capacity by technology



Generation availability

The availability factor represents the percentage of the 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 gas generation has increased from 2016 levels.

FIGURE 9: Annual availability factor by technology



Most available coal power dispatched

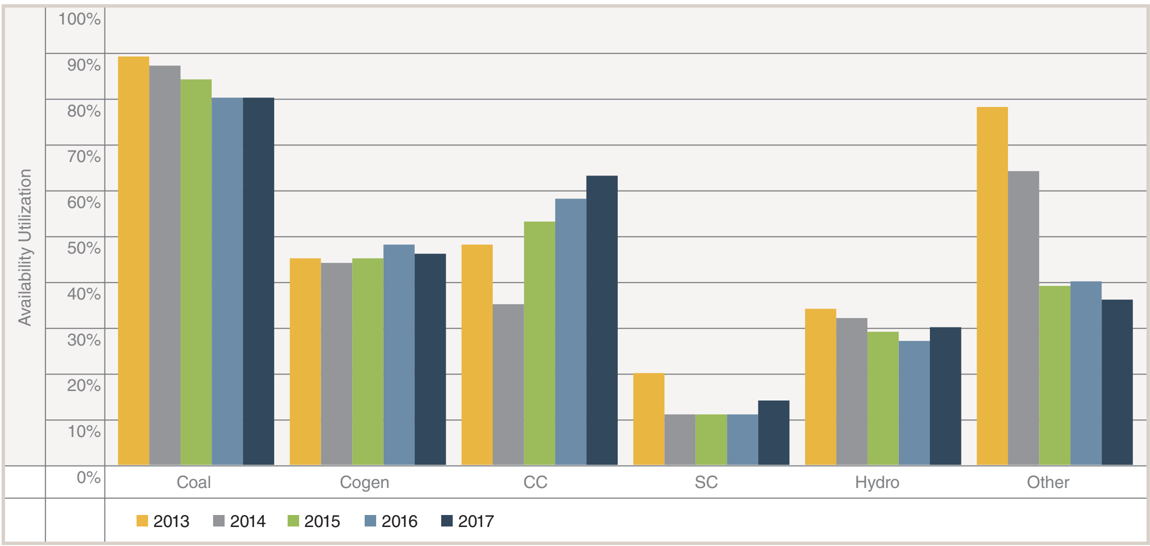
Availability utilization represents the percentage of the available power that was dispatched to serve system load. Availability utilization is calculated as the ratio of net-to-grid generation to the available capability. Wind generation is excluded from this calculation since all available wind power was fully utilized. Figure 10 illustrates the annual availability utilization by generation technology.

Over the five-year period between 2013 and 2017, the availability utilization of coal generation was consistently highest among dispatchable generation technologies. This relationship persists because coal generation tends to offer its energy to the market at low prices. As a result, coal generation is usually dispatched before any higher-priced generation technology, and provides a stable baseload supply of energy. Despite this behaviour, coal utilization steadily declined from 2013 to 2016 due to the return of coal assets from long-term outages and increased competition from baseload combined-cycle gas generation. Coal utilization in 2017 remained at the same level as 2016.

Although both coal generation and cogeneration gas are baseload technologies, the availability of coal generation significantly exceeds that of cogeneration gas. 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.

The availability utilization of simple-cycle gas is 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. The increase in baseload generation capacity since 2013 reduced the frequency of high pool price hours, lowering pool price and, with it, simple-cycle gas utilization. However, in 2017 maintenance outages of baseload generation technologies and weather-driven demand increased availability utilization of simple-cycle gas generation by three per cent.

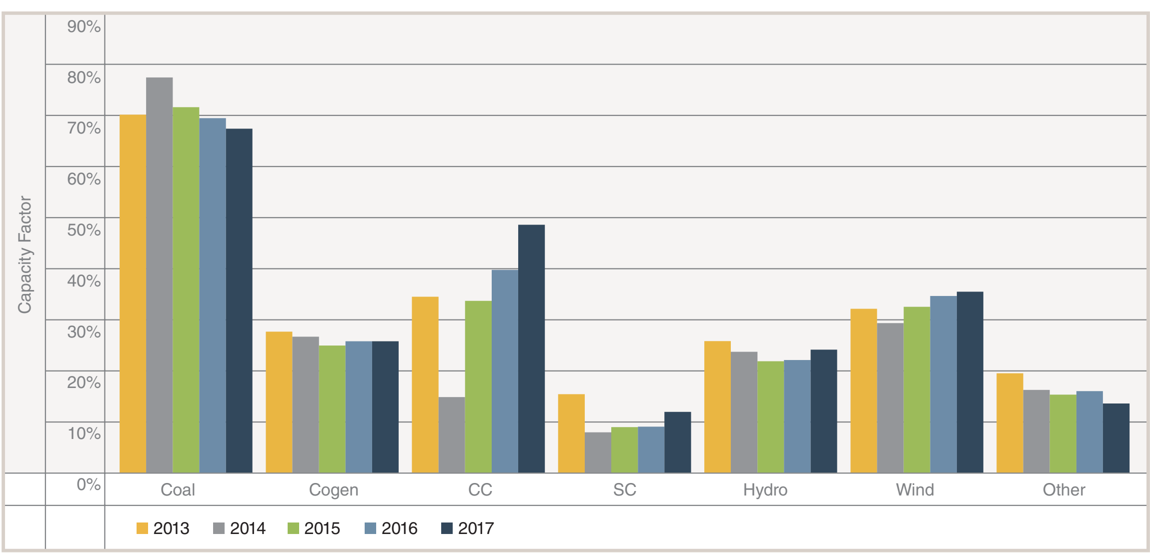
FIGURE 10: Annual availability utilization factor by technology



Coal generation capacity most utilized

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



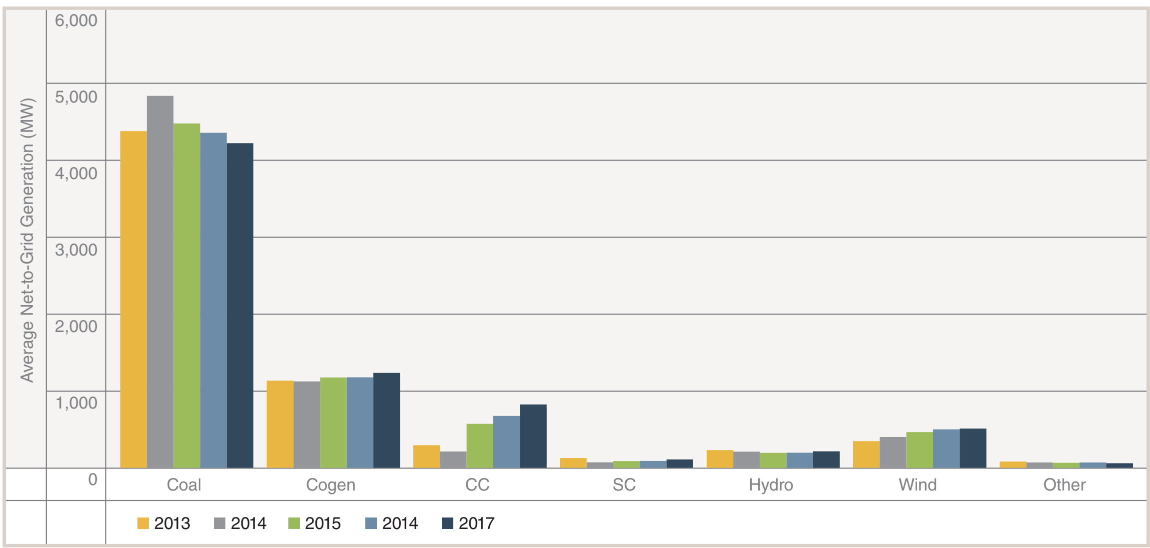
Over the five-year period between 2013 and 2017, the capacity factor of coal generation was consistently higher than the capacity factor of any other generation technology. In 2017, the capacity factor of coal reached 67 per cent—on average, for every 100 MW of installed capacity, coal generation delivered 67 MWh to the AIES each hour. This result is consistent with the baseload operation of coal generation technology.

Over the same period, the capacity factor of simple-cycle gas generation was consistently lowest among generation technologies. In 2017, the capacity factor of simple-cycle gas generation was only 12 per cent. This result is consistent with the peaking operation of simple-cycle gas generation.

Coal generation supplied 59 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 2017, coal generation supplied almost two-thirds of energy delivered to the AIES. Gas generation technologies delivered 30 per cent of net-to-grid generation. Renewable generation provided the remaining 11 per cent. Wind generation provided the majority of energy from renewable sources: seven per cent of total net-to-grid generation was provided by wind power alone.

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



Simple-cycle gas realizes highest achieved premium to pool price

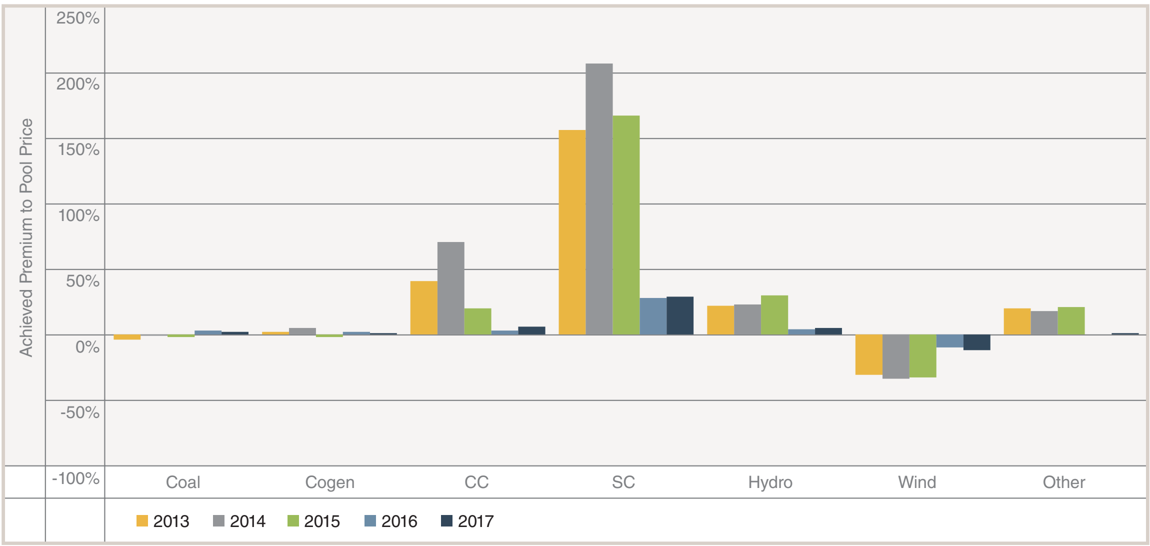
Achieved price represents the average price realized in the wholesale energy market for electricity delivered to the grid. Achieved price is calculated as the weighted average of hourly pool price, where the price in each settlement interval is weighted by the net-to-grid generation. The achieved margin 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 both premiums and discounts to pool price in 2016 and 2017 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 2016 and 2017 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.

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 and cogeneration gas. The relatively low cost of coal generation implies that 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 2017, coal and cogeneration gas technologies realized premiums to pool price between one and two per cent.

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 only 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 last five years, simple-cycle gas generation achieved the highest premium across all generation technologies in Alberta. In 2017, simple-cycle gas remained reasonably constant compared to 2016 and received 30 per cent premium to pool price.

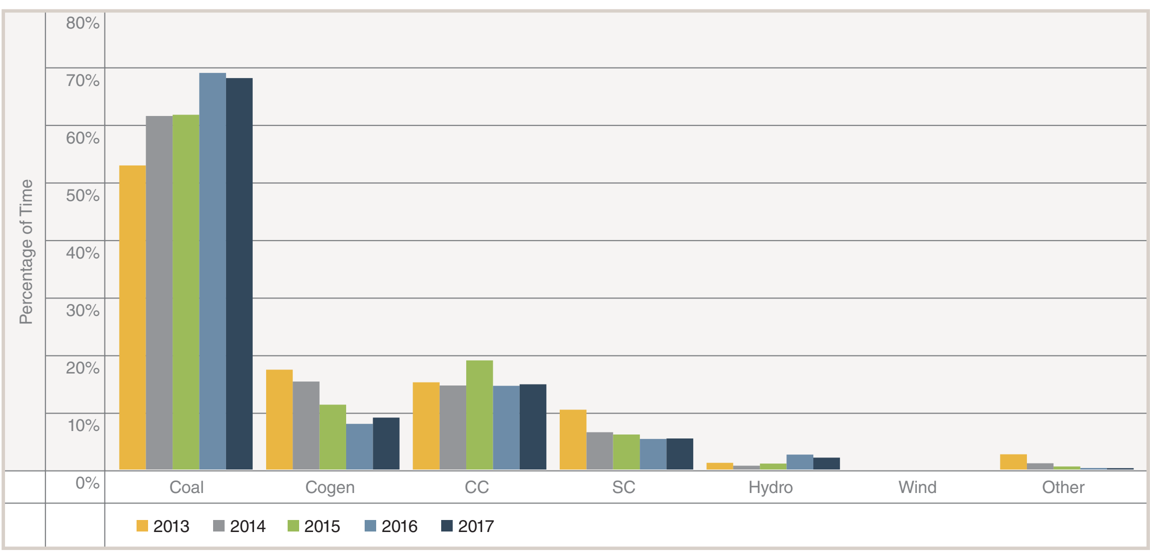
Wind generation is the only technology that consistently achieved a discount to pool price—that is, the achieved premium is consistently negative. This discount occurs due to technological limitations and geographic concentration. Wind power cannot control its operational schedule; the availability of 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 displaces a significant quantity of power from the energy market merit order. Wind generation tends to reduce the system marginal price, which lowers its achieved price. In 2017, wind generation received a 12 per cent discount to pool price.

Coal generation sets marginal price in 68 per cent of hours

Figure 14 illustrates how frequently each generation technology set 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- and off-peak hours. Coal generation disproportionately set the system marginal price during off-peak hours when load was low; however, coal assets also set the marginal price in more than half of the on-peak hours in 2017. The high frequency where low-priced coal generation set the price contributed to the relatively low average pool price in 2017.

FIGURE 14: Annual marginal price-setting technology



Supply adequacy

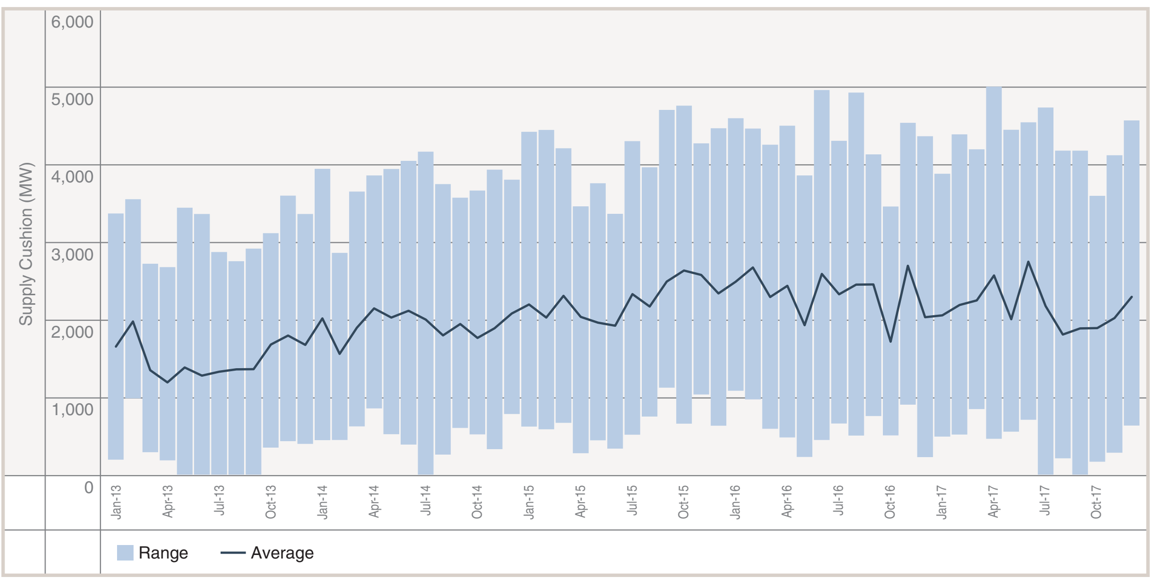
Supply adequacy expresses the ability of the system to serve demand. In general, supply adequacy increases as generation capability increases, and decreases as system load increases. This report evaluates supply adequacy using two common measures: supply cushion and reserve margin. An in-depth analysis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

Supply cushion decreased eight 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 remained available to respond to unplanned outages. Over 2017, the average supply cushion decreased eight per cent to 2,156 MW. The decrease in average supply cushion occurred due to generation outages and low imports during periods of high demand in the third and fourth quarters of the year.

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 2017, supply shortfall conditions occurred twice. The first occasion was a three-hour interval on July 26 which resulted in declaring an Energy Emergency Alert (EEA) 1 followed by an EEA2. The second one was a one-hour interval on Sept. 26 that led to EEA1 alert. Figure 15 shows the monthly supply cushion over the past five years.

FIGURE 15: Monthly supply cushion



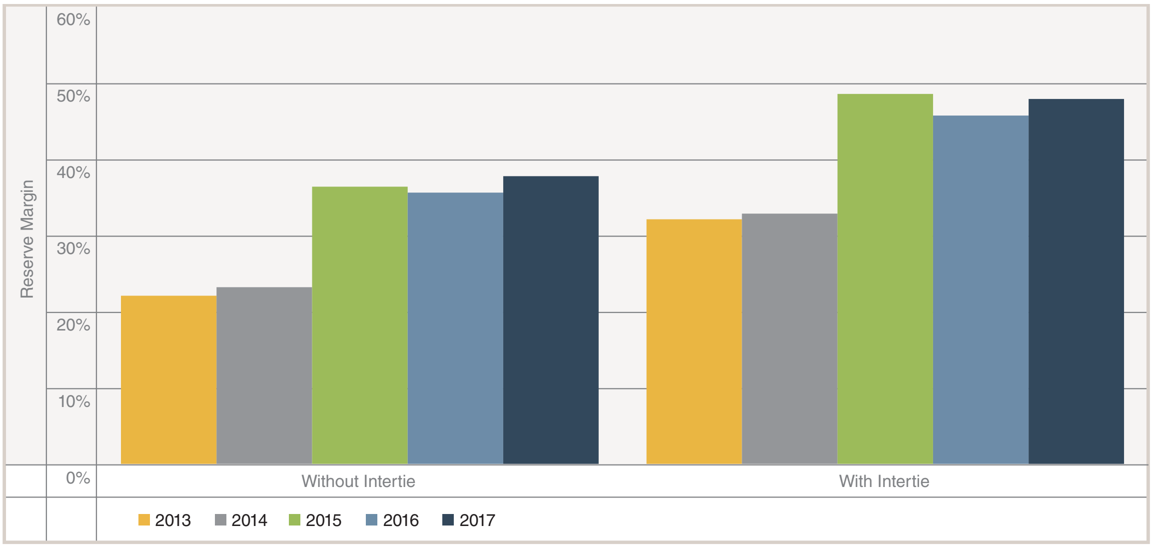
Reserve margin increased slightly

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 2012 excluded the generation capability of the two Sundance coal units to reflect the extended forced outage. 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 slight increase in the reserve margin from 2016 to 2017 indicates that growth in generation capacity over 2017 slightly exceeded the increased peak system demand.

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.

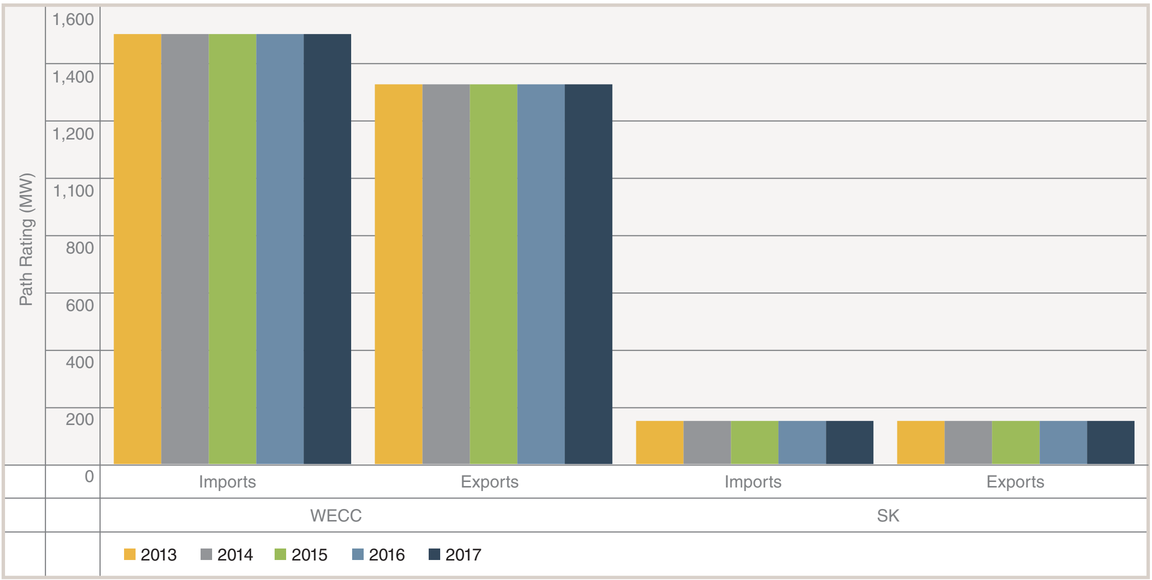
Transfer path rating remained stable

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 2016 and 2017.

FIGURE 17: Annual path rating by transfer path

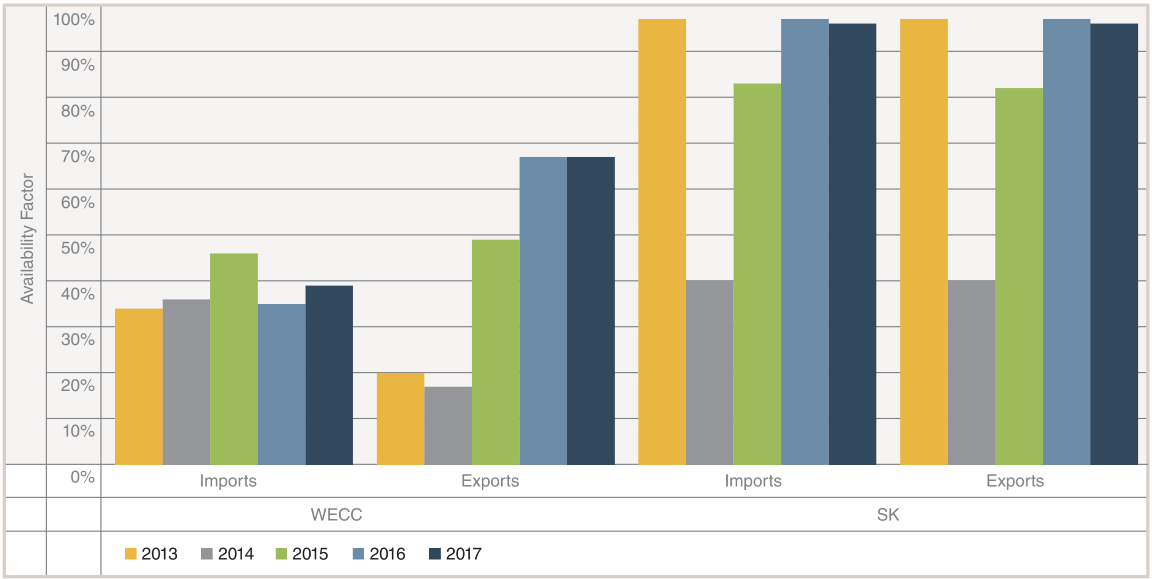


Intertie availability factor

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.

FIGURE 18: Annual availability factor by transfer path



Import activity increases

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 2017, both import and export utilization increased from 2016 levels between Alberta and other WECC members. The import utilization increased along the Saskatchewan tie-line while the export decreased.

FIGURE 19: Annual availability utilization by transfer path

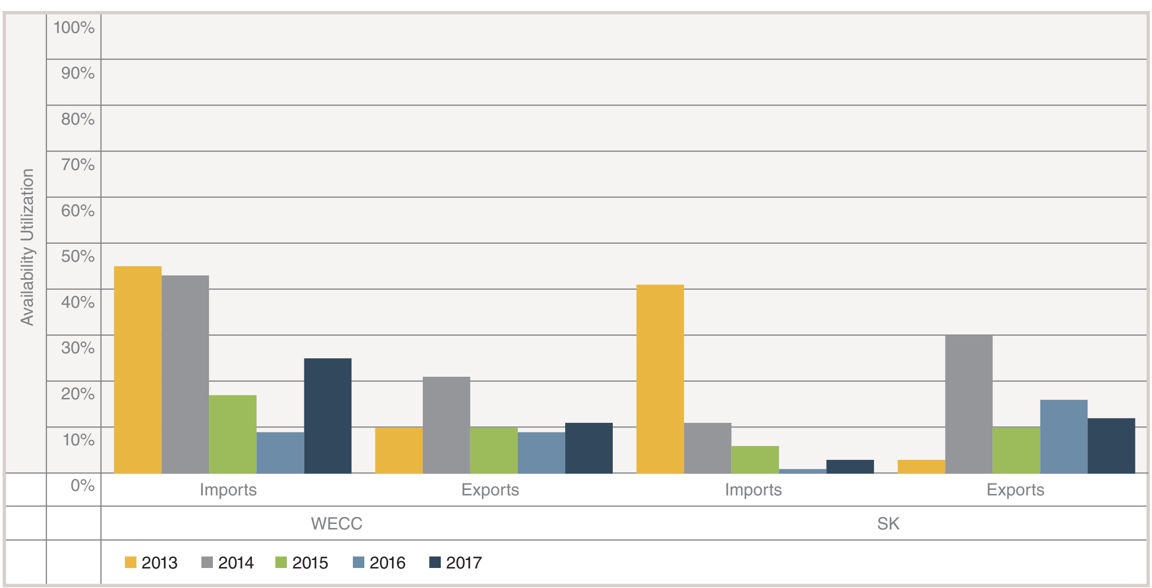


Figure 20 shows the annual interchange utilization between Alberta and the WECC regions over the past five years. Interchange utilization represents the ratio of net imports across the intertie to its transfer capability. Net imports include the volume of operating reserve procured on the intertie. The utilization calculation reflects the limits of the interties with B.C. and Montana, the combined operating limits, and the Alberta system operating limit. Over 2017, Alberta imported energy from the WECC region in 35 per cent of hours, and exported energy in 44 per cent of hours.

FIGURE 20: Annual interchange utilization with WECC region

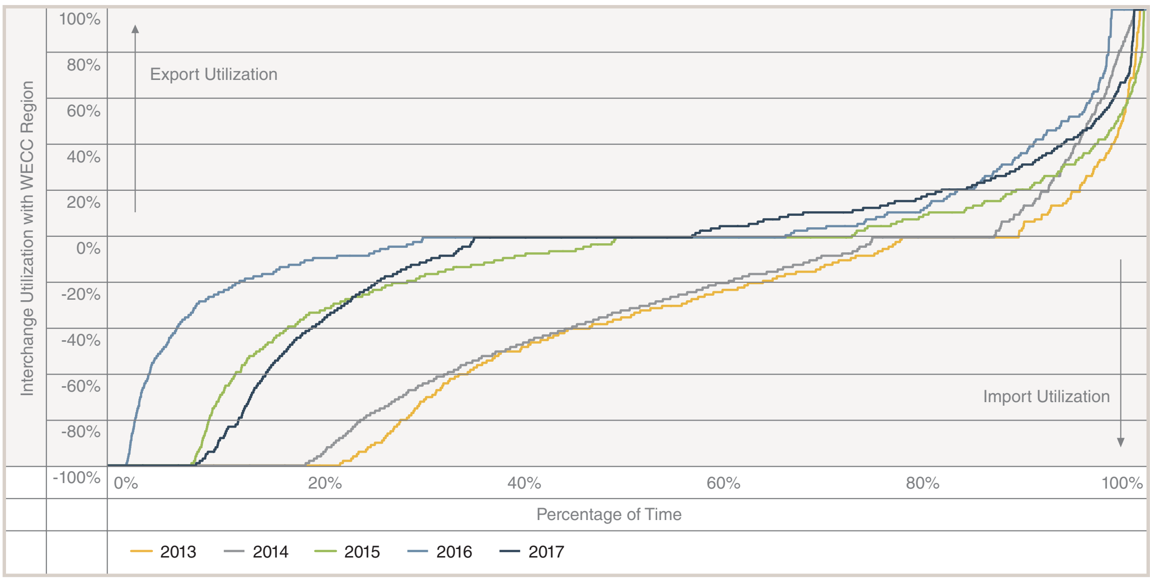
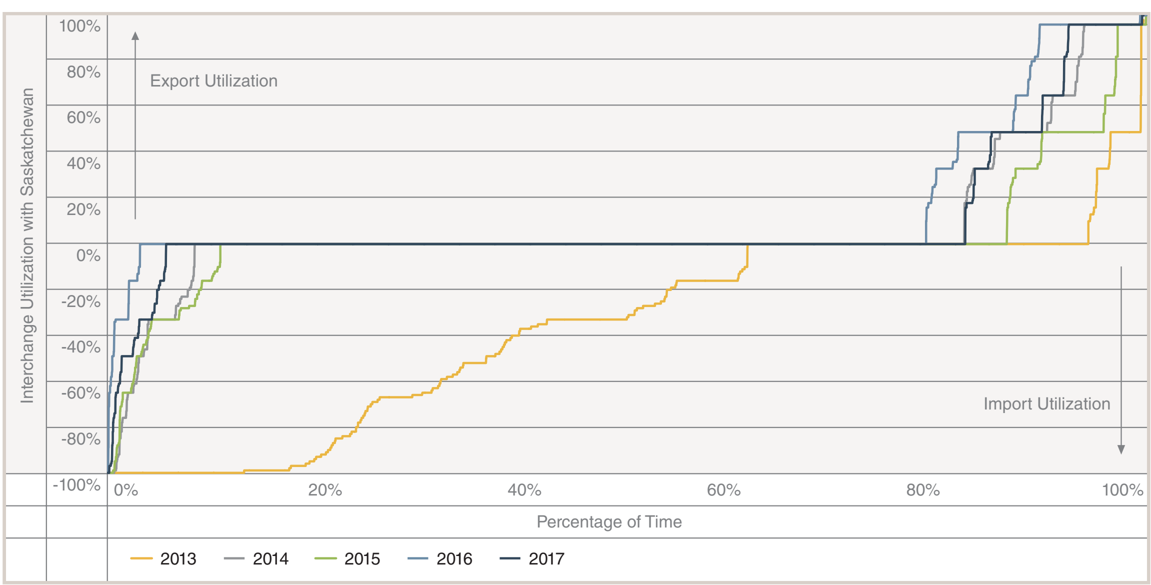


Figure 21 shows the annual interchange utilization between Alberta and Saskatchewan over the past five years. In 2017, Alberta imported energy from Saskatchewan in six per cent of hours, and exported energy in 17 per cent of hours.

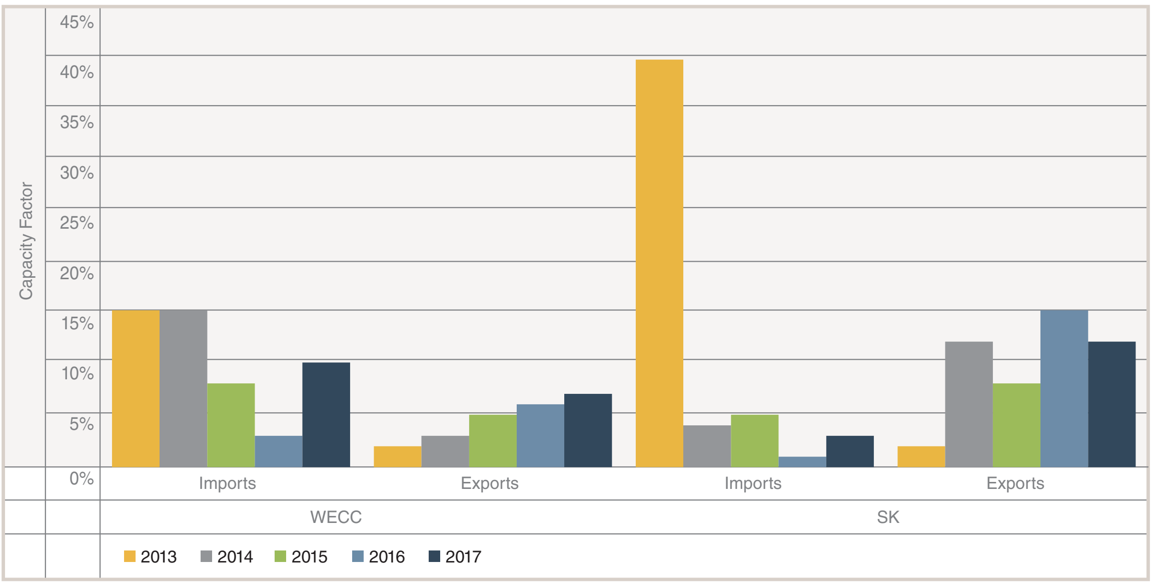
FIGURE 21: Annual intertie utilization with Saskatchewan



Capacity factor reflects 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.

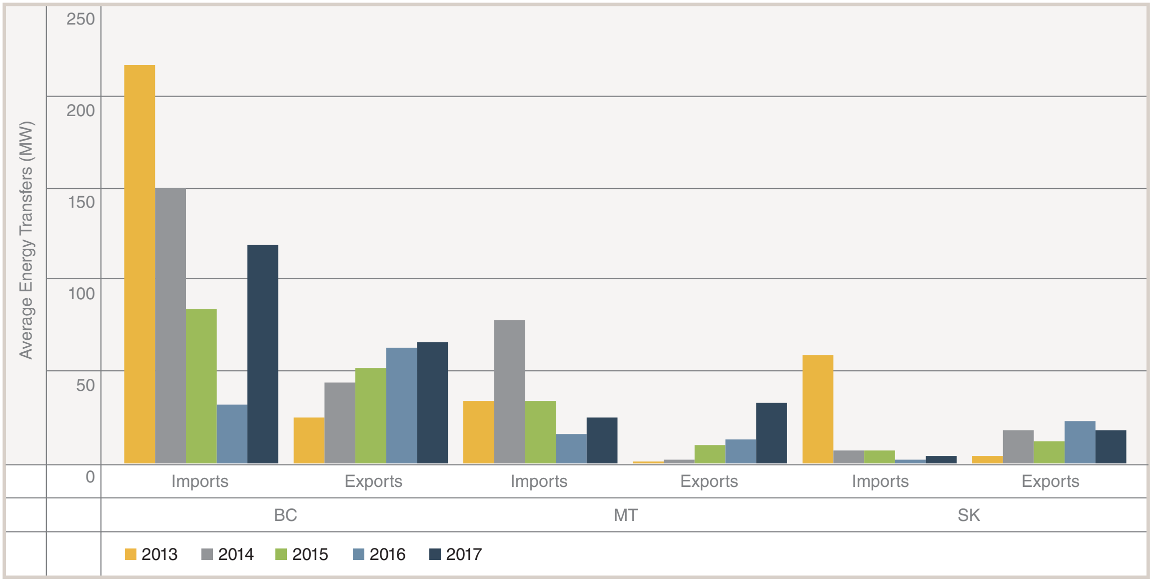
FIGURE 22: Annual capacity factor by transfer path



Alberta was a net importer

Figure 23 illustrates the annual average energy transferred from each province or state. In 2017, Alberta was a net importer. Net imports from B.C. increased from 2016 levels due to an increase in hydro generation in the region, specifically in springtime. Alberta exported more electricity to Montana and Saskatchewan than it imported.

FIGURE 23: Annual intertie transfers by province or state

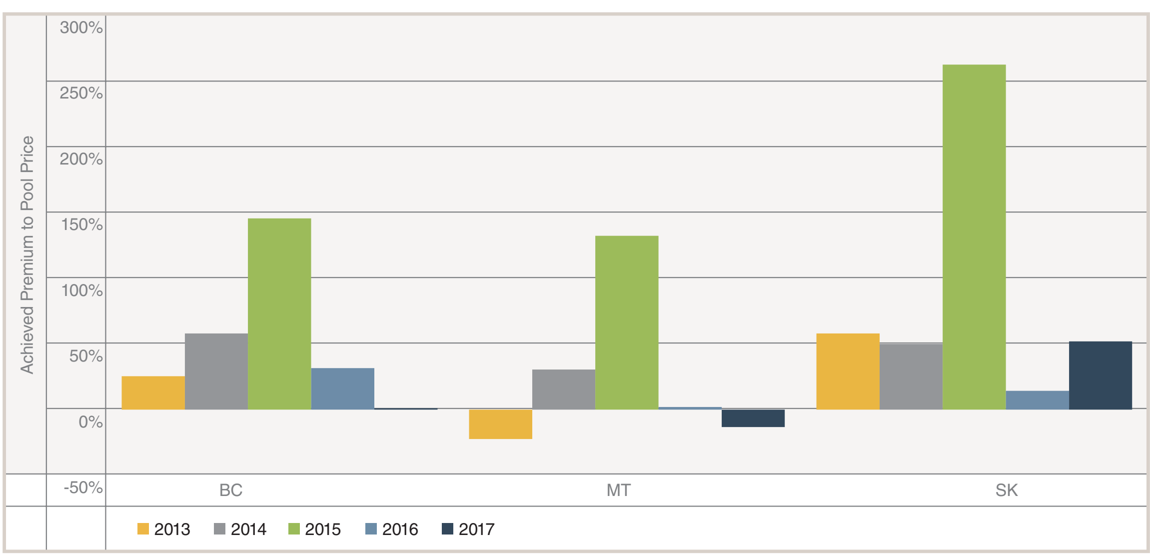


Achieved premium to pool price

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.

Low pool price in 2017 limited profit opportunities for importers, the achieved premium to pool price on imported energy decreased for British Columbia and Montana: the achieved premium ranged between negative 13 per cent and one 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

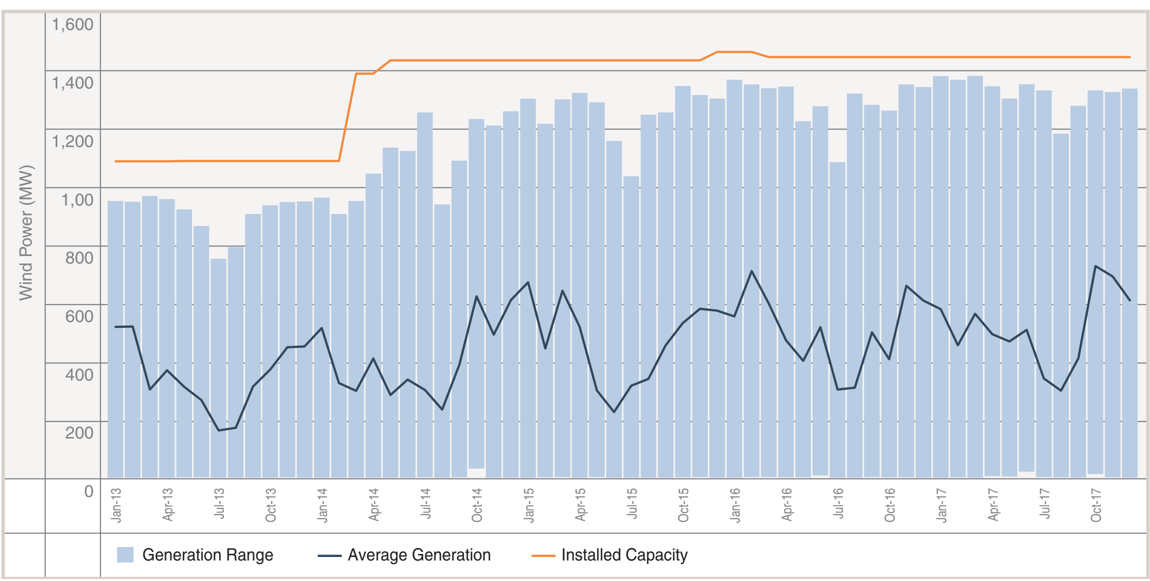
Table 3 summarizes the annual statistics for wind generation. Over 2017, installed wind generation capability remained unchanged from 2016. At the end of the year, wind farms made up nine per cent of the total installed generation capacity in Alberta. Energy produced by wind generation served five per cent of total load in 2017.

TABLE 3: Annual wind generation statistics

Year	2012	2013	2014	2015	2016	2017
Installed wind capacity at year end (MW)	1,087	1,088	1,434	1,463	1,445	**1,445**
Total wind generation (GWh)	2,574	3,013	3,519	4,089	4,402	**4,486**
Wind generation as a percentage of total AIL	3%	4%	4%	5%	6%	**5%**
Average hourly capacity factor	32%	32%	30%	33%	35%	**35%**
Maximum hourly capacity factor	92%	89%	88%	94%	93%	**96%**
Wind capacity factor during annual peak AIL	5%	50%	3%	7%	15%	**6%**

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

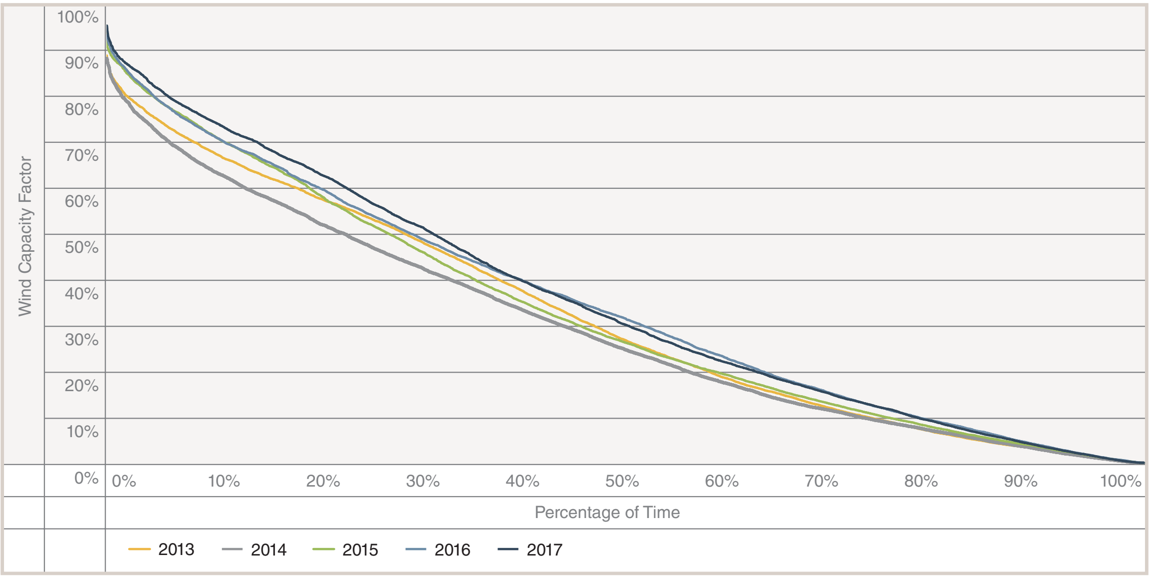
FIGURE 25: Monthly wind capacity and generation



Wind capacity factor remains constant

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 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 remained relatively constant over the last five years. The capacity factor of wind generation averaged 35 per cent over 2017: for every 100 MW of installed wind capacity, wind power generated an average of 35 MW of energy each hour. The capacity factor—the ratio of net-to-grid generation to installed capacity—for wind generation is comparable to that of cogeneration and combined-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 2017, 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 2017. The average capacity factor and the achieved price for central wind slightly exceeded those for southern wind. For each megawatt of installed capacity, a wind farm in central Alberta generated more energy than a wind farm in southern Alberta, and for each unit of energy generated, a central wind farm earned slightly more revenue than a southern wind farm.

TABLE 4: 2017 Regional wind statistics

Region	South	Central	Total
Installed wind capacity at year end (MW)	1,096	349	**1,445**
Total wind generation (GWh)	3,366	1,120	**4,486**
Average wind capacity factor	35%	37%	**35%**
Achieved price ($/MWh)	$19.20	$20.34	**$19.48**

Ancillary services

Cost of operating reserve increased 21 per cent

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 using the Watt-Ex trading system. 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 for use when active reserve is insufficient. Standby reserve is dispatched as required 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.

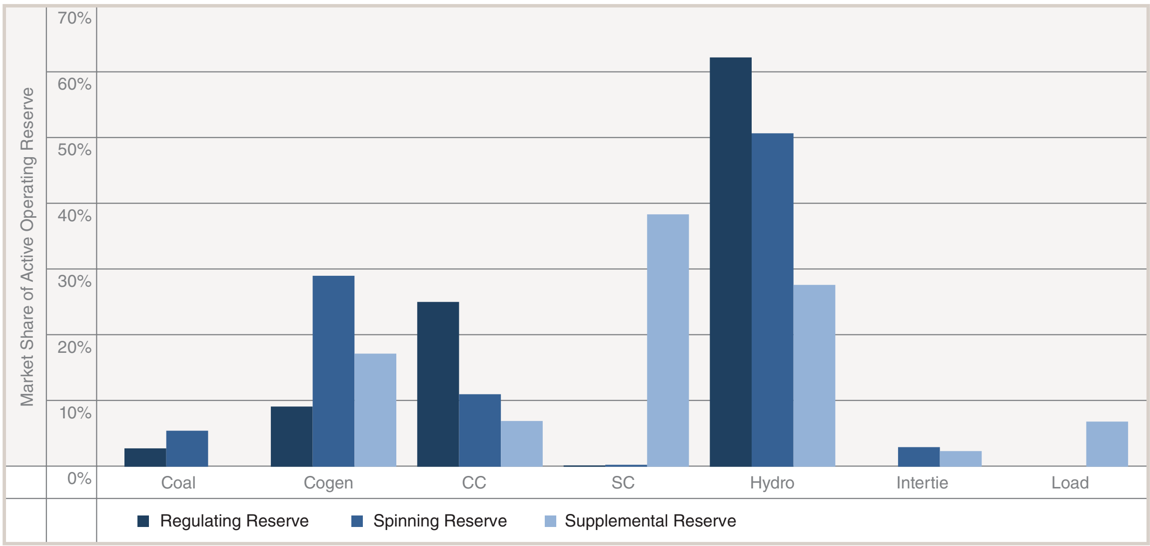
Table 5 summarizes the total cost of operating reserve over the past five years. The total cost of operating reserve in 2017 increased 21 per cent to 81 million, driven by the effect of higher pool prices on the cost of active reserves and an increase in the amount of contingency reserves procured. Increased activation of standby reserves further increased the total cost of operating reserves.

TABLE 5: Annual operating reserve statistics

Year	2013	2014	2015	2016	2017
Volume *(GWh)*					
Active procured	6,019	6,006	5,333	5,262	**5,449**
Standby procured	2,144	2,142	2,140	2,049	**2,058**
Standby activated	77	65	136	85	**236**
Cost *($-millions)*					
Active procured	$341	$168	$105	$53	**$67**
Standby procured	$19	$14	$13	$12	**$8**
Standby activated	$10	$3	$20	$2	**$6**
Total	$369	$185	$138	$67	**$81**

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 2017, hydro generation obtained a greater market share of all active operating reserve products than any other technology.

FIGURE 27: 2017 Market share of active operating reserves



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 higher-priced energy 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.

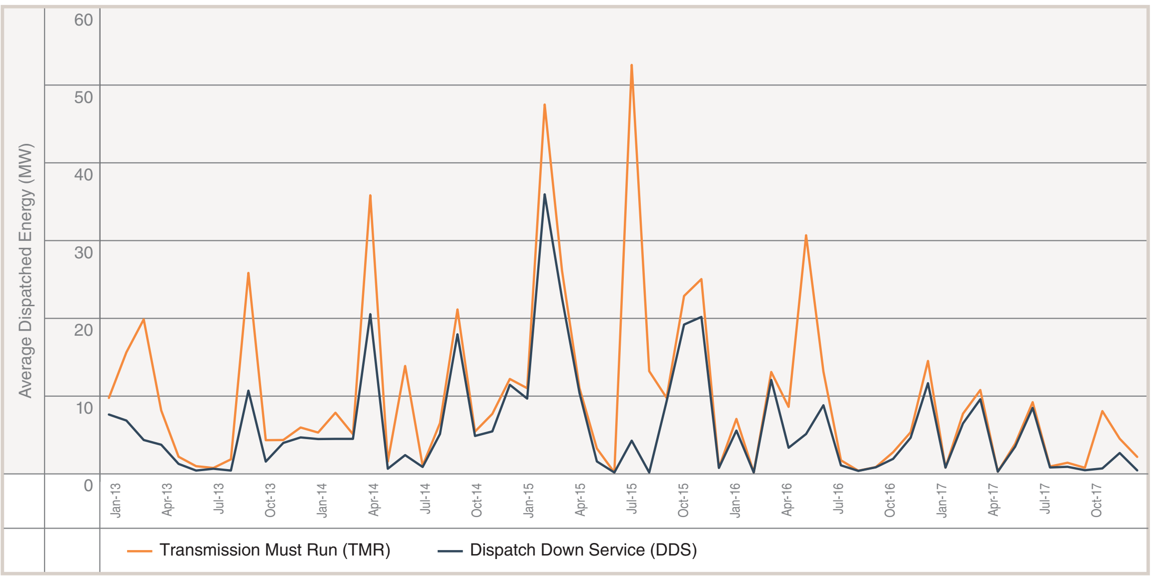
DDS requirements are limited to the amount of dispatched TMR. DDS cannot offset more energy than is dispatched under TMR service. In 2017, DDS offset 68 per cent of dispatched TMR volume. Table 6 summarizes the annual TMR and DDS statistics over the past five years. The annual cost of DDS in 2017 totaled $0.1 million. The total cost of DDS is allocated between energy suppliers in proportion to the volume of energy that they generated or imported.

TABLE 6: Annual TMR and DDS statistics

Year	2013	2014	2015	2016	2017
Transmission Must-Run					
Dispatched energy (GWh)	71	88	161	71	**35**
Dispatch Down Service					
Total payments ($-millions)	$0.6	$1.2	$1.6	$0.5	**$0.1**
Dispatched energy (GWh)	32	59	95	39	**24**
Average charge ($/MWh)	$0.01	$0.02	$0.02	$0.01	**$0.00**

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 payment statistics

Year	2013	2014	2015	2016	2017
Payments to suppliers on the margin					
Average range ($/MWh)	18.80	7.54	5.99	1.08	**2.35**
Total payments ($-millions)	2.61	1.16	1.25	0.16	**0.21**
Transmission constraint rebalancing					
Price effect ($/MWh)				-0.01	**-0.02**
Constrained-down generation (GWh)				2.4	**1.3**
Total payments ($-millions)				0.01	**0.02**

Payments to suppliers on the margin increased 31 per cent

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 31 per cent to $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 117 per cent to $2.35/MWh in 2017.

Transmission constraint rebalancing

The revised transmission constraint management (TCM) rule introduced a new pricing mechanism to mitigate the effects of transmission constraints on pool price. When constraints on the transmission system prevent in-merit generation from supplying energy to the AIES, system controllers must dispatch generators that would otherwise be out of merit. Until November 2015, this normally out-of-merit generation could set the system marginal price.

After the revised TCM rule became effective in November 2015, only generation that would be in merit in an unconstrained transmission system can set system marginal price. If a transmission constraint requires system controllers to constrain in-merit generation, the energy dispatched to replace the constrained-down generation (CDG) does not influence system marginal price. Instead, this replacement energy receives an additional uplift payment, referred to as transmission constraint rebalancing (TCR).

In 2017, the implementation of the revised TCM rule reduced the average pool price by $0.02/MWh from the value that would have been calculated under the previous methodology. Constraints on the transmission system required system controllers to curtail 1.3 GWh of in-merit energy and additional TCR payments to market participants totaled $20,000.

Final notes

As the market evolves throughout 2018 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 reserves market statistics and a broad selection of historical datasets. Reports are produced with the best information available at the time, and will change as better 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.

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