AESO 2021 Annual Market Statistics

MARCH 2022

Contents

Executive summary

The Alberta Electric System Operator (AESO) facilitates a fair, efficient, and openly competitive (FEOC) market for electricity and provides for the safe, reliable, and economic operation of the Alberta Interconnected Electric System (AIES). *The AESO 2021 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 information that underlies the tables and figures in this report.

In 2021, 228 participants in the Alberta wholesale electricity market transacted approximately $12.7 billion of energy. The annual average pool price for wholesale electricity increased 118 per cent from its previous-year value to $101.93/megawatt hour (MWh). The average natural gas price increased 60 per cent, averaging $3.40/gigajoule (GJ). The average spark spread, based on a 7.5 GJ/MWh heat rate, increased 147 per cent to $76.39/MWh from its previous-year value. The main reason for the increase in the average pool price was driven by the change in offer behaviour of larger market participants following the expiration of the Power Purchase Agreements (PPAs) at the end of 2020.

Price	2020	2021	Year/Year Change
Pool price	$46.72/MWh	$101.93/MWh	+118%
Gas price	$ 2.12/GJ	$ 3.40/GJ	+60%
Spark spread at 7.5 GJ/MWh	$30.81/MWh	$76.39/MWh	+147%

Load	2020	2021	Year/Year Change
Average AIL	9,462 MW	9,728 MW	+2.8 %
Winter peak	11,729 MW	11,939 MW	+1.8%
Summer peak	10,532 MW	11,721 MW	+11.2%

The average Alberta Internal Load (AIL) increased by 2.8 per cent over 2020 values due to a further lessening of COVID-19 pandemic impacts, as well an increase in industrial demand. Extreme temperatures led to a new summer peak of 11,721 MW (up 11 per cent from 2020) and a new winter and AIL peak of 11,939 MW (set in January 2022).

Installed generation capacity at the end of 2021 was 17,224 MW, up 5.9 per cent from 2020. An increase of 1,117 MW in renewable capacity was offset by the retirement of a 400-MW coal unit. A total of five former coal assets finished their conversion to purely gas-fired generation during the year. Gas-fired generation provided 54 per cent of net-to-grid generation, while coal generation provided 31 per cent.

Price of electricity

Pool price increased 118 per cent

The pool price averaged $101.93/MWh over 2021—an increase of 118 per cent from 2020. 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. every day; the remaining hours of the day make up the off-peak period. In 2021, the average pool price during the on-peak period increased 124 per cent to $122.61/MWh, and the off-peak average pool price increased 97 per cent to $60.58/MWh. The spark spread is a high-level measurement that estimates the profitability of operating a generic combined-cycle natural gas baseload generation asset in the energy market. In 2021, the spark spread increased 147 per cent from a year earlier.

Pool prices in 2021 were the highest they've been since 2000, in nominal terms.[1] There are many reasons for this, including higher demand (including new all-time records in the summer and winter due to extreme weather events), higher gas prices, untimely outages, an increase in the carbon tax, and an increase in offer prices by many large market participants after the expiry of the PPAs.

Table 1 summarizes historical price statistics over the 10-year period between 2012 and 2021.

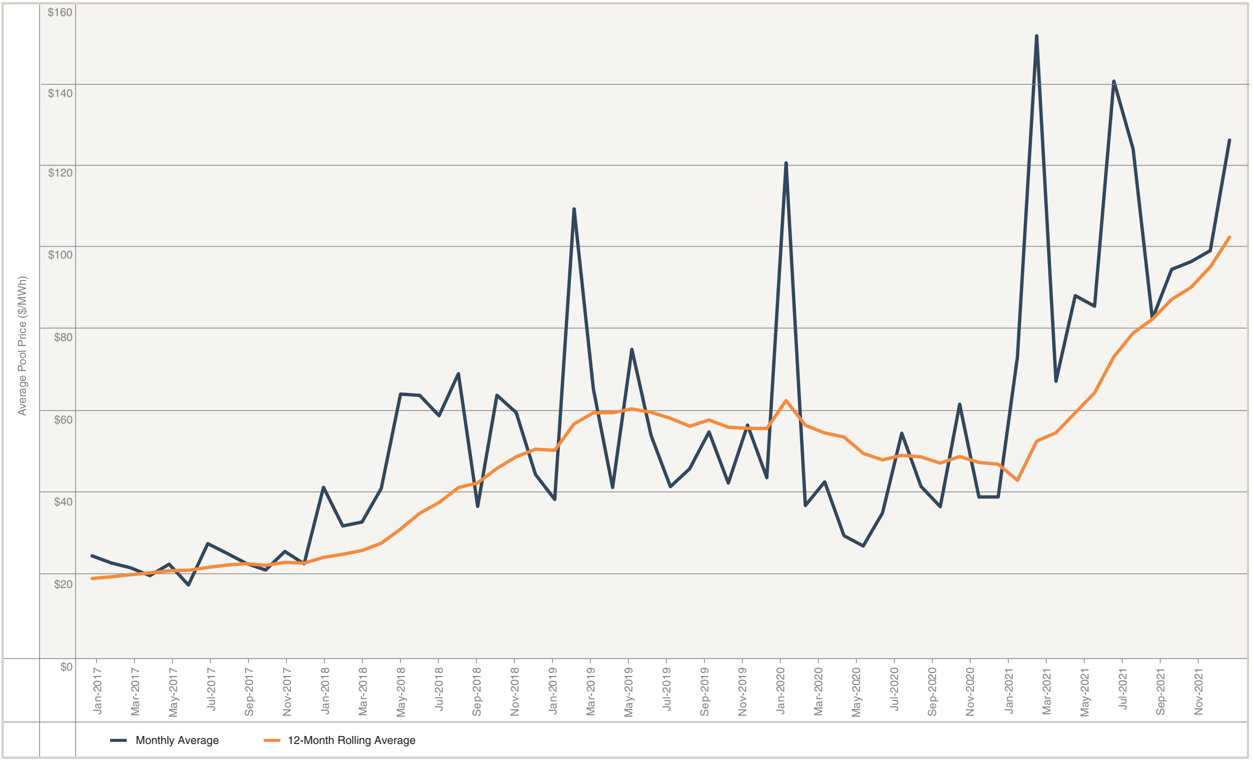
TABLE 1: Annual market price statistics

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Pool price ($/MWh)										
Average	64.32	80.19	49.42	33.34	18.28	22.19	50.35	54.88	46.72	**101.93**
On-peak average	84.72	106.13	61.48	40.73	19.73	24.46	59.28	64.12	54.72	**122.61**
Off-peak average	23.51	28.29	25.28	18.55	15.37	17.64	32.47	36.40	30.71	**60.58**
Spark spread at 7.5 (GJ/MWh)										
Average	47.28	57.58	17.56	14.12	2.77	6.70	39.54	42.21	30.81	**76.39**

The pool price sets the wholesale price of electricity—the settlement price for all transactions in the energy market. Figure 1 shows the monthly average pool price over the past five years. For 2021, the monthly average pool price ranged from a high of $151.98/MWh in February to a low of $66.92/MWh in March.

[1] In real terms, 2021 had the highest average pool price since 2008. See MSA's Q4 report at Quarterly Reports (albertamsa.ca).

FIGURE 1: Monthly average pool price



The hourly price of electricity in Alberta reflects the economic principles of supply and demand. For any given hour, generators submit offers specifying the amount of power that they will provide 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 offers are arranged from lowest to highest price to create the energy market 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 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, in nominal terms, equaled or exceeded a specified level. Figure 2 shows on-peak pool price duration curves for the last five years. In 2021, prices were significantly higher than the previous four years. For example, 2021 had 38 per cent of the on-peak hours priced at $75 or higher. The highest percentage of hours above $75 in the 2017-2020 period was 13 per cent of the hours in 2019.

FIGURE 2: On-peak pool price duration curve

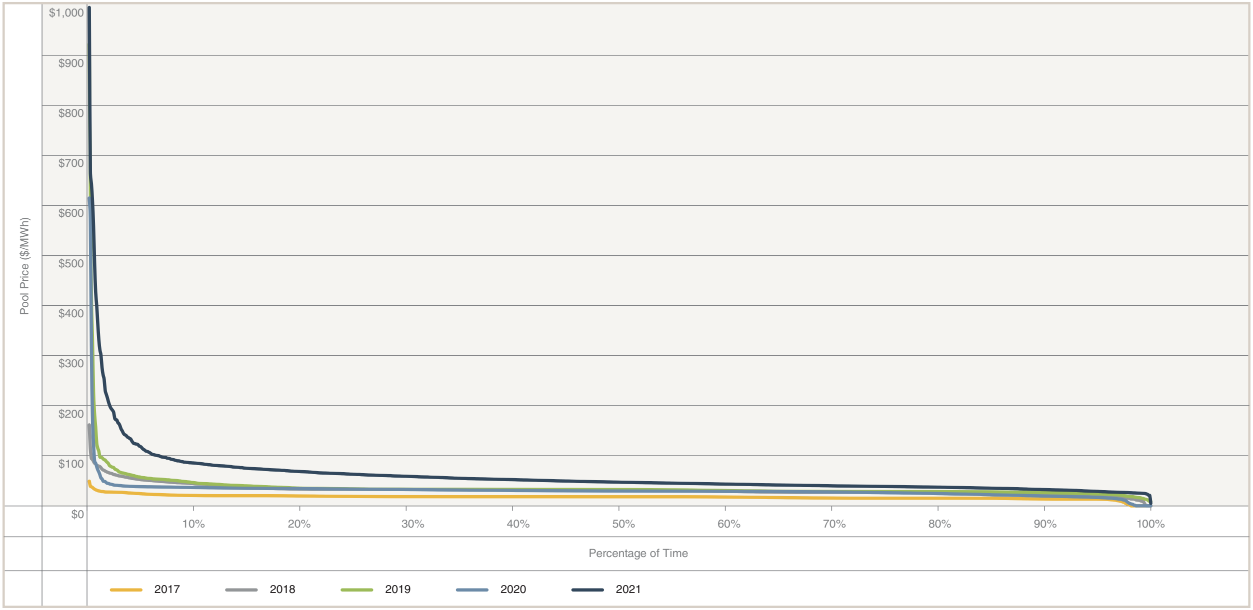
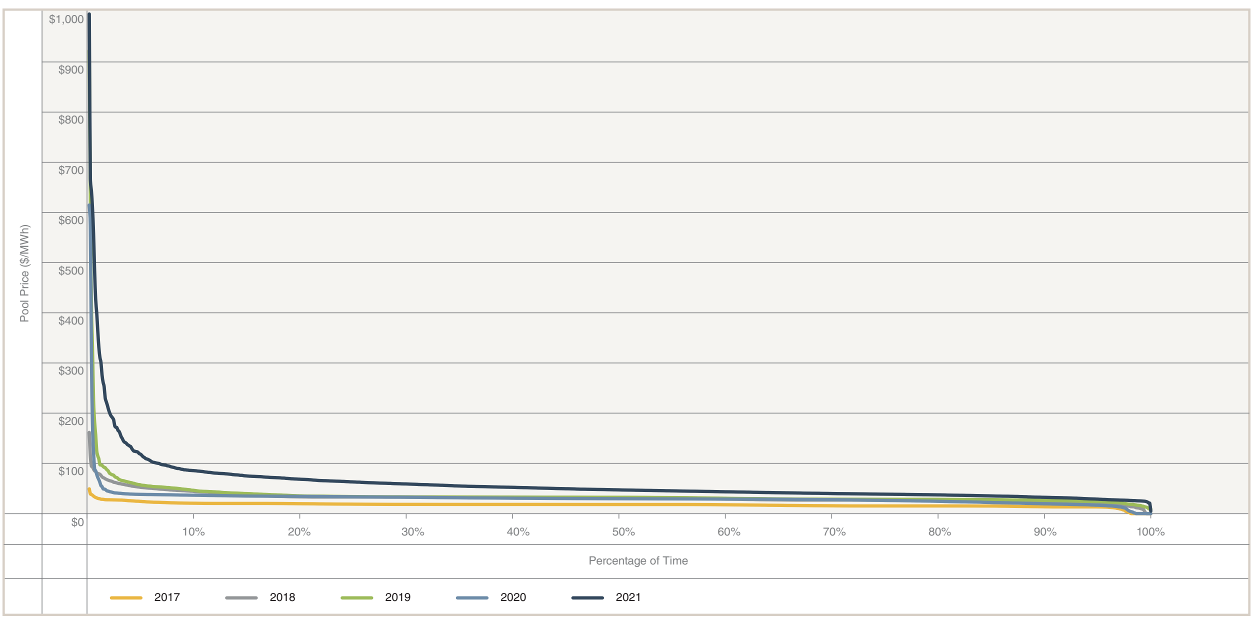


Figure 3 shows off-peak pool price duration curves for the last five years. While not as pronounced as the on-peak duration curves, a similar contrast in the duration of high prices can be seen between 2021 and the 2017-2020 period.

FIGURE 3: Off-peak pool price duration curve



The reliability of the AIES depends on the ability of system controllers to dispatch supply to satisfy demand. During supply shortfall conditions and supply surplus conditions, electricity supply is mismatched with demand requirements. Left unaddressed, these system conditions could threaten the stability of the AIES. To preserve system stability, System Controllers must follow prescribed mitigation procedures to maintain the balance between supply and demand.

Supply shortfall conditions occur when Alberta load exceeds the total supply available for dispatch from the merit order. When supply shortfall conditions occur, mitigation procedures are deployed under which system controllers may halt exports, re-dispatch imports and ancillary services, and finally, curtail firm load. When the system operator is forced to curtail firm load, the system marginal price is set to the administrative price cap of $1,000/MWh.

In 2021, there were no supply shortfall conditions. However, there were three instances in which the Alberta-B.C. Intertie tripped, causing firm load to be shed. The instances occurred on Feb. 21, Feb. 22, and June 3.

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. In 2021, there were two supply surplus events that totaled less than an hour. This compares to the 68 hours of supply surplus that occurred in 2020. The year-over-year change is due to higher demand in 2021.

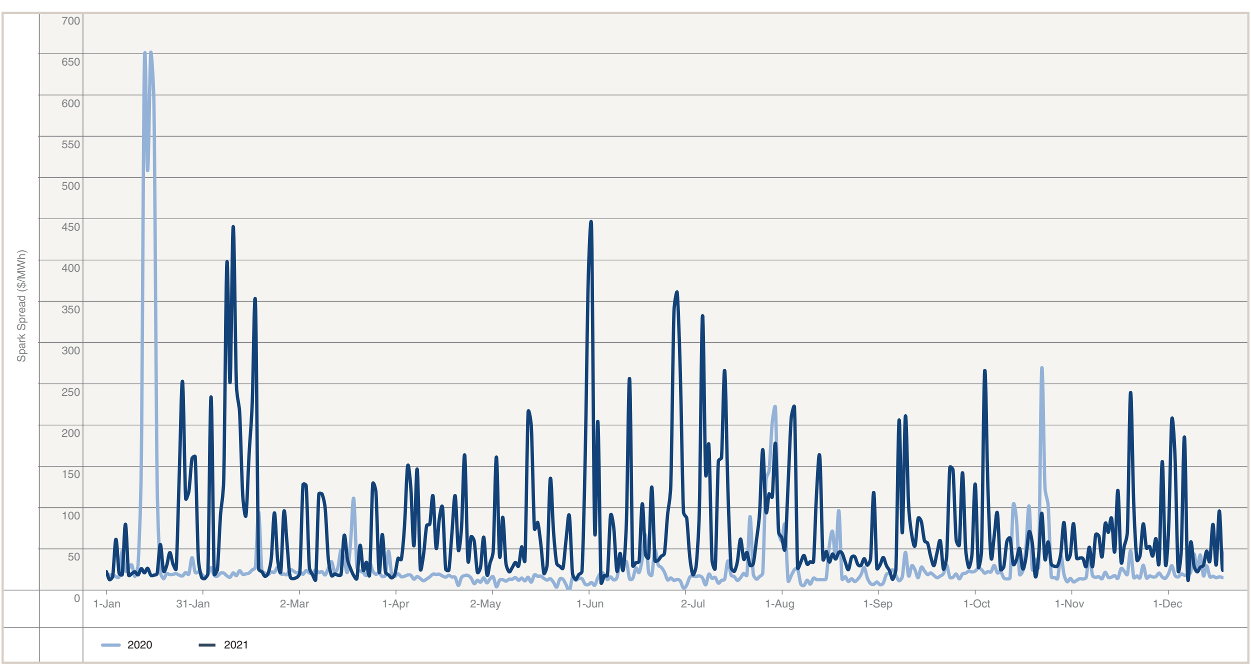
Spark spread increased 147 per cent

As mentioned above, the spark spread is a high-level measurement that estimates the profitability of operating a generic combined-cycle natural gas baseload generation asset in the energy market. 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, which measures the efficiency of the generation asset, and the unit cost of natural gas. The operating heat rate represents the amount of fuel energy required to produce one unit of electrical energy and varies between generating units. This report uses an operating heat rate of 7.5 GJ/MWh to assess market conditions for a reasonably efficient combined-cycle gas generation asset.

A positive spark spread implies that baseload operation would be profitable for the generic gas-fired generator; a negative spark spread implies that baseload operation would be unprofitable. The spark spread is indicative and does not include costs such as variable operations or maintenance.

Figure 4 shows the daily average spark spread for 2020 and 2021. In 2021, the average spark spread increased 147 per cent to $76.39/MWh. This is the highest nominal spark spread seen in the last 20 years.

FIGURE 4: 2020 and 2021 daily average spark spread



There are numerous reasons for higher spark spreads in 2021. These include generation outages, untimely lack of renewable generation and reduced imports at critical times. The year-over-year change in carbon price is estimated to have added to the offer price of individual units anywhere from $0.22, for combined cycle units, to $6.30, for sub-critical coal units.[2] However, given the consistent high spark spreads across a variety of fundamental conditions, the biggest factor is believed to be the combination of demand growth and the increased offer prices made by larger market participants following the expiration of the PPAs at the end of 2020.

Alberta 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 the summer season starts on May 1 and ends on October 31. In the seasonal load discussions in this report, the terms winter and summer refer to these seasonal definitions.

Average load increased 2.8 per cent

Table 2 summarizes annual demand statistics over the past 10 years. In 2021, average AIL increased by 2.8 per cent to 9,728 MW. In addition, a new annual peak load of 11,729 MW occurred on Feb. 9, 2021. The increase in AIL from 2020 to 2021 was driven by the reduced impact of the COVID-19 pandemic and increased oil and gas production and associated servicing industries resulting from the increase in energy prices. Despite the higher year-over-year load, the average load was still slightly below the record set in 2018 of 9,741 MW.

TABLE 2: Annual load statistics

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Alberta Internal Load (AIL)										
Total (GWh)	75,574	77,451	79,949	80,257	79,560	82,572	85,330	84,925	83,115	**85,214**
Average (MW)	8,604	8,841	9,127	9,162	9,055	9,426	9,741	9,695	9,460	**9,728**
Maximum (MW)	10,609	11,139	11,169	11,229	11,458	11,473	11,697	11,471	11,698	**11,729**
Minimum (MW)	6,828	6,991	7,162	7,203	6,595	7,600	7,819	8,024	7,579	**7,976**
Average growth	2.4%	2.8%	3.2%	0.4%	-1.1%	4.1%	3.3%	-0.5%	-2.4%	**2.8%**
Load factor	81%	79%	82%	82%	79%	82%	83%	85%	81%	**83%**
System load										
Average (MW)	6,620	6,778	7,024	6,998	6,919	7,121	7,183	7,030	6,844	**6,946**
System-to-AIL ratio	77%	77%	77%	76%	76%	76%	74%	72%	72%	**71%**
Implied BTF load	1,984	2,063	2,103	2,164	2,139	2,305	2,558	2,664	2,618	**2,782**

AIL represents, in an hour, system load plus load served by on-site generating units, including those within an industrial system and the City of Medicine Hat. It is consistent with the generation and load represented on the AESO's Current Supply and Demand page[3] and it is the main load measure used by the AESO to denote total load within the province. System load represents the total electric energy billed to transmission consumers in Alberta and Fort Nelson, British Columbia (B.C.),[4] plus transmission losses.

[2] Estimated using the change in carbon price from $40 to $50 and the estimated cost by generation type. See page 21 of https://www.aeso.ca/assets/Uploads/grid/lto/2021-Long-term-Outlook.pdf.

[3] http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet

[4] For system access service provided in accordance with the ISO tariff under Rates DTS, FTS, and DOS.

The load factor represents the ratio of the average AIL to the peak 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 increase in the load factor for 2021 reflects the increase in base demand, for reasons mentioned above.

The system-load-to-AIL-ratio describes how much of total load in Alberta is using the bulk transmission system. In 2021, 71 per cent of Alberta's load was using the bulk transmission system, down from 72 per cent in 2020. The difference between AIL and system load represents load that does not use the bulk transmission system, commonly referred to as "behind-the-fence" (BTF) load. Normally, BTF load includes industrial load self-supplied by large on-site cogeneration plants, as well as all load on distribution networks that can be served by small roof-top solar panels. However, for the purposes of this BTF calculation, only load self-supplied by large generators (i.e., greater than 5 MW) is captured. Gross load on distribution facility owner (DFO) transmission networks is not readily available to the AESO, only the net metered load.

The implied average hourly BTF load was 2,782 MW for 2021, up 6.2 per cent from an implied 2,618 MW of BTF load in 2020. BTF load is primarily driven by industrial load, especially oil sands sites, while system load is roughly half residential or/commercial and half industrial. Therefore, the larger increase in BTF load compared to system load is indicative of AIL growth being driven primarily by industrial load.

Figure 5 shows the monthly average load in 2020 and 2019. The year-over-year differences in January to March, as well as December, were primarily due to weather-related events. From April to September 2020, load was depressed due to the impacts of COVID-19 restrictions, while 2021 saw those restrictions lifted somewhat. June and July 2021 were also impacted by extreme temperatures. Overall, average demand was up 267 MW compared to 2020.

FIGURE 5: 2020 and 2021 monthly average load

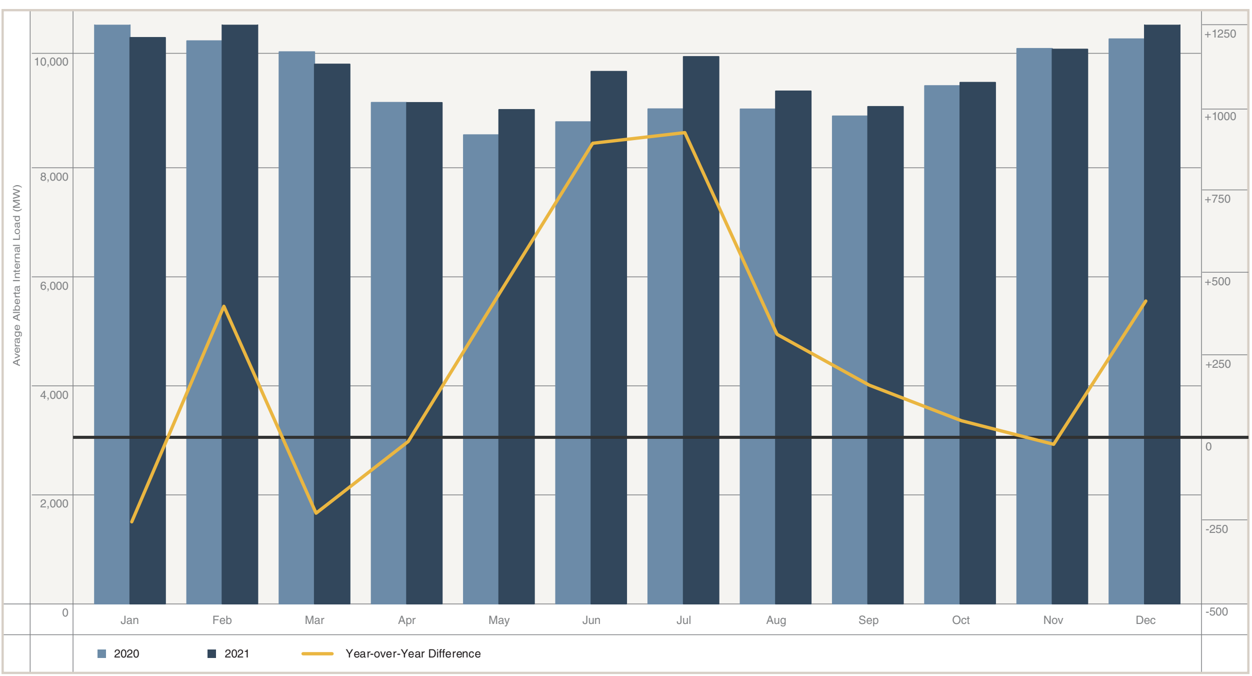
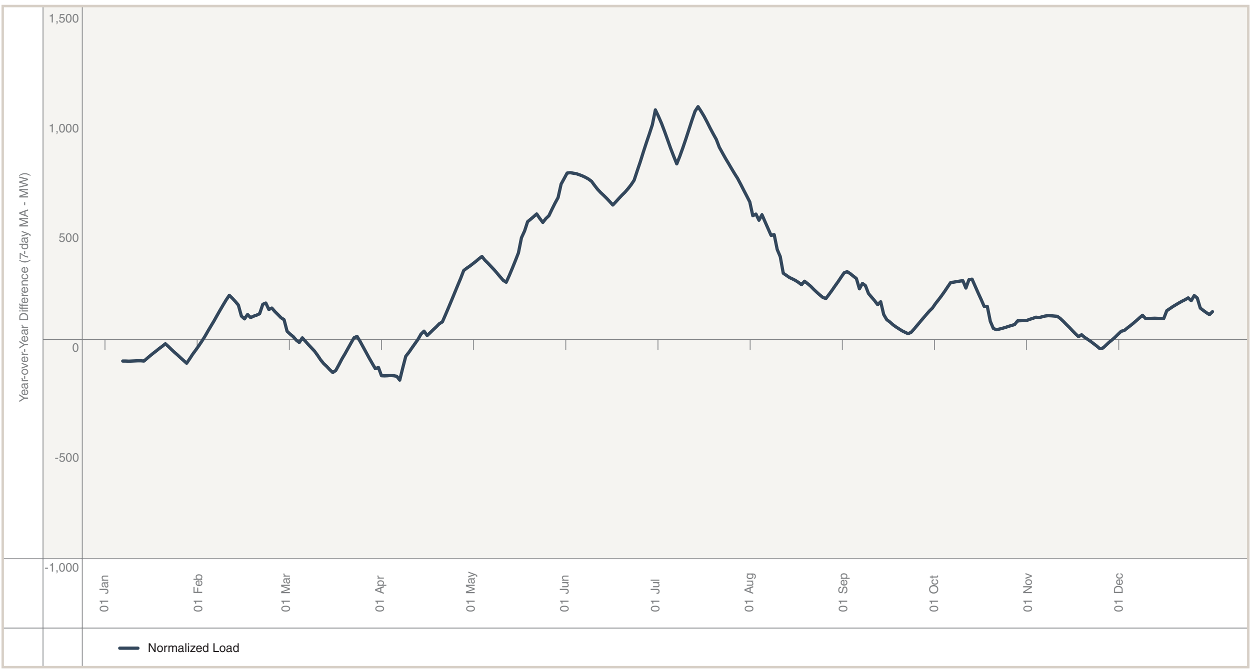


Figure 6 shows the weekly average weather-normalized load in 2021 as a difference to the weather-normalized load in 2020. Weather-normalization is the process of using a model to estimate what load would have been in multiple years if they had the same temperatures. This reduces the impact that temperatures have on load, allowing for the observation of structural changes. The first quarter of 2021 was very similar to 2020. Starting in April 2021, load moved closer to pre-COVID-19 levels. The year-over-year difference started declining in July due to comparison with increasing 2020 load from the gradual lifting of pandemic restrictions.

FIGURE 6: 2021 weekly average weather-normalized load vs. 2020



The load duration curve represents the percentage of time that AIL was greater than or equal to the specified load. Figure 7 plots the annual load duration curve for on-peak hours (Hour-ending [HE] 8-23 for all days), while Figure 8 plots the same thing, but for off-peak hours (HE1-7,24). Both look at the past five years. For the on-peak hours, roughly 25 percent of the highest demand hours in 2021 were higher than 2018 and 2019. These were mostly related to extreme weather events that occurred in February, June, July, and December 2021. Conversely, approximately 60 per cent of on-peak hours in 2021 had lower demand than the current record demand year of 2018. This suggests that demand, which declined due to the fall in oil prices in 2019 and the COVID-19 pandemic in 2020, did not completely return to previous levels. It's a similar picture in the off-peak hours, although the lower demand levels are very close for 2018, 2019 and 2021, indicating that baseload demand has mostly returned.

FIGURE 7: Annual load duration curves – on-peak hours

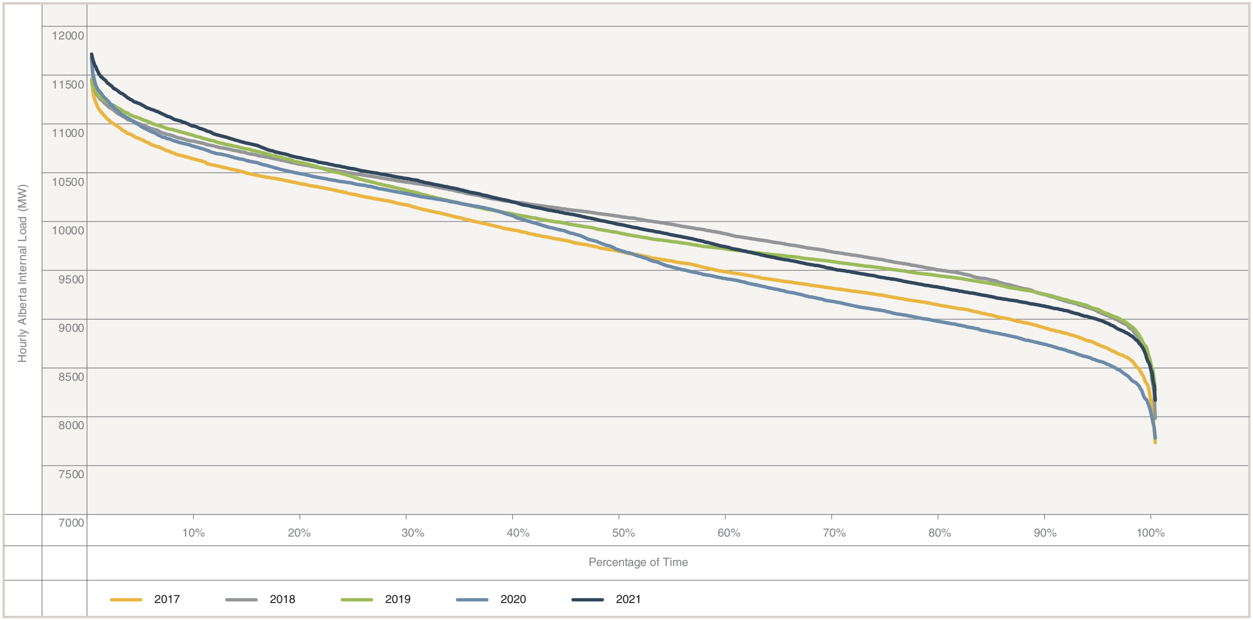
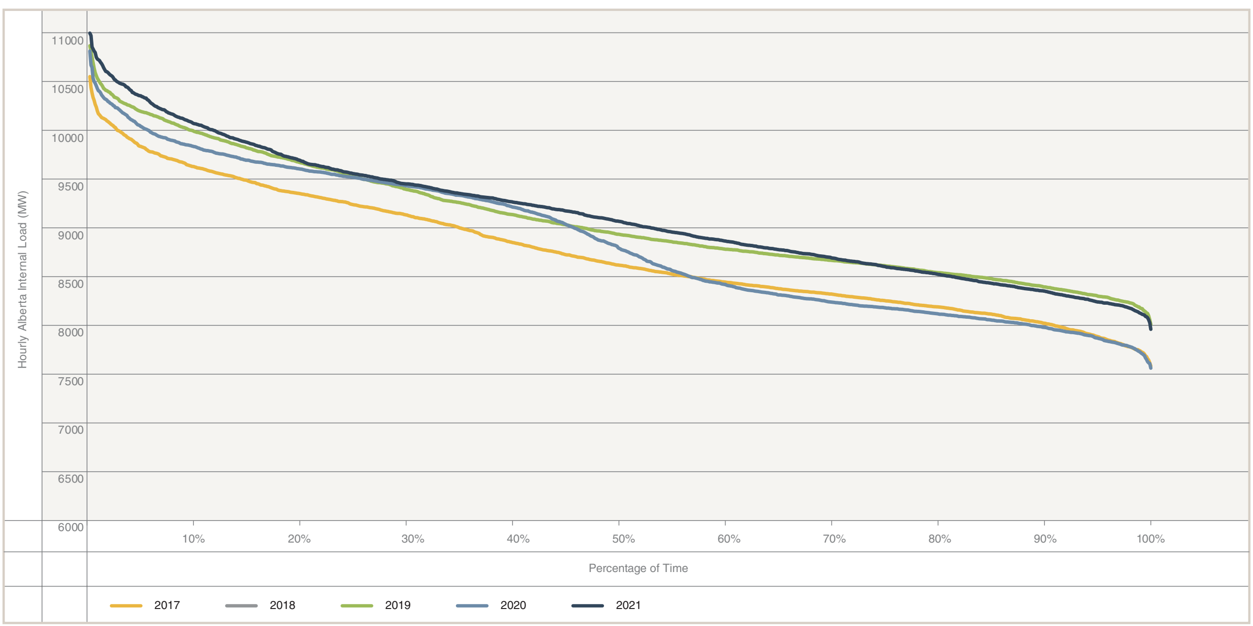


FIGURE 8: Annual load duration curves – off-peak hours



Seasonal load

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. Alberta has always been a winter-peaking region. However, there was an unusual occurrence within calendar 2021, with the summer peak being only 8 MW lower the calendar year peak. At the time of writing, the highest all-time peak load of 11,939 MW was set in the Winter 2021 on Jan. 3, 2022.

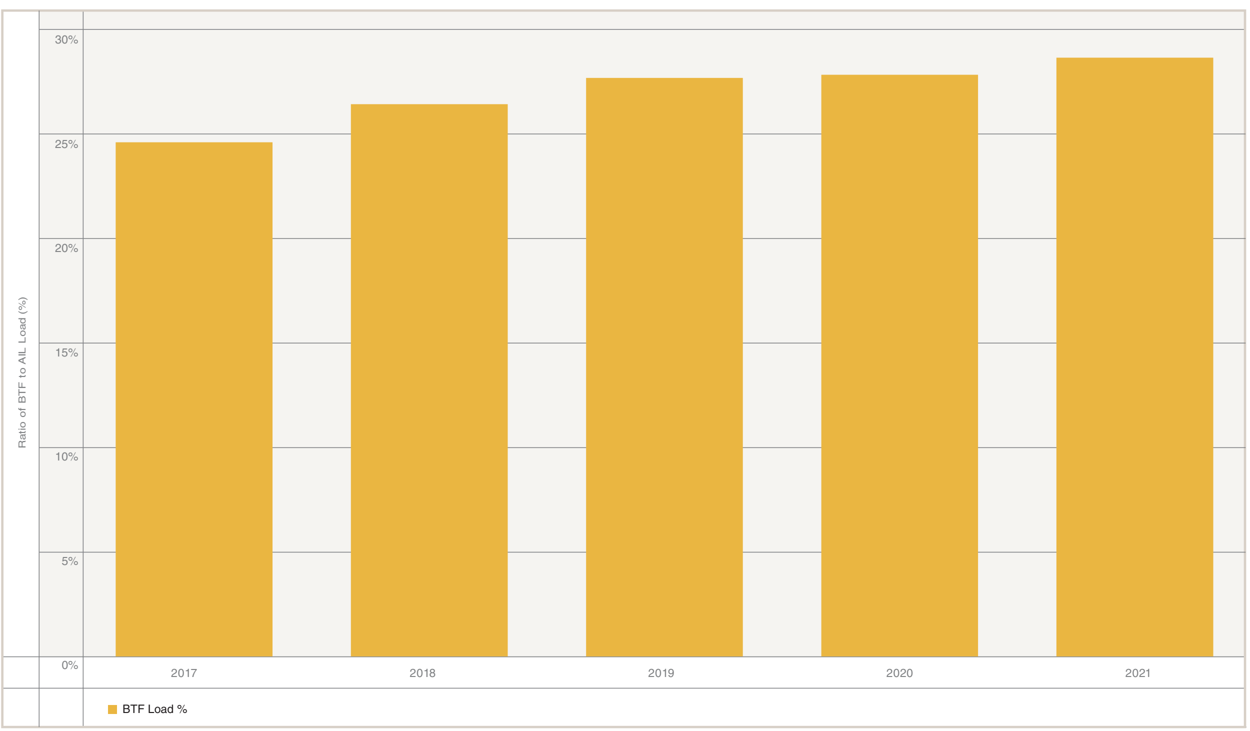
TABLE 3: Seasonal peak load

Season	Peak AIL (MW)	Date	Calendar Year
Summer 2017	10,852	2017-07-27	2017
Winter 2017	11,697	2018-01-11	2018
Summer 2018	11,169	2018-08-10	2018
Winter 2018	11,471	2019-02-12	2019
Summer 2019	10,822	2019-08-02	2019
Winter 2019	11,698	2020-01-14	2020
Summer 2020	10,532	2020-10-26	2020
Winter 2020	11,729	2021-02-09	2021
Summer 2021	11,721	2021-06-29	2021
Winter 2021 (to Feb 2021)	11,939	2022-01-03	2022

Behind-the-Fence load

In Alberta, AIL represents the overall load within the province. System load is the load total of AESO-metered demand plus transmission system losses. BTF is the difference between AIL and system load. It is the estimated amount of load that is self-supplied and/or served by large (less than 5 MW) distribution-connected generation. Since 2012, the percentage of AIL from BTF load has increased from 21 per cent to 29 per cent. In absolute terms, this is an increase of just under 800 MW over the last 10 years.

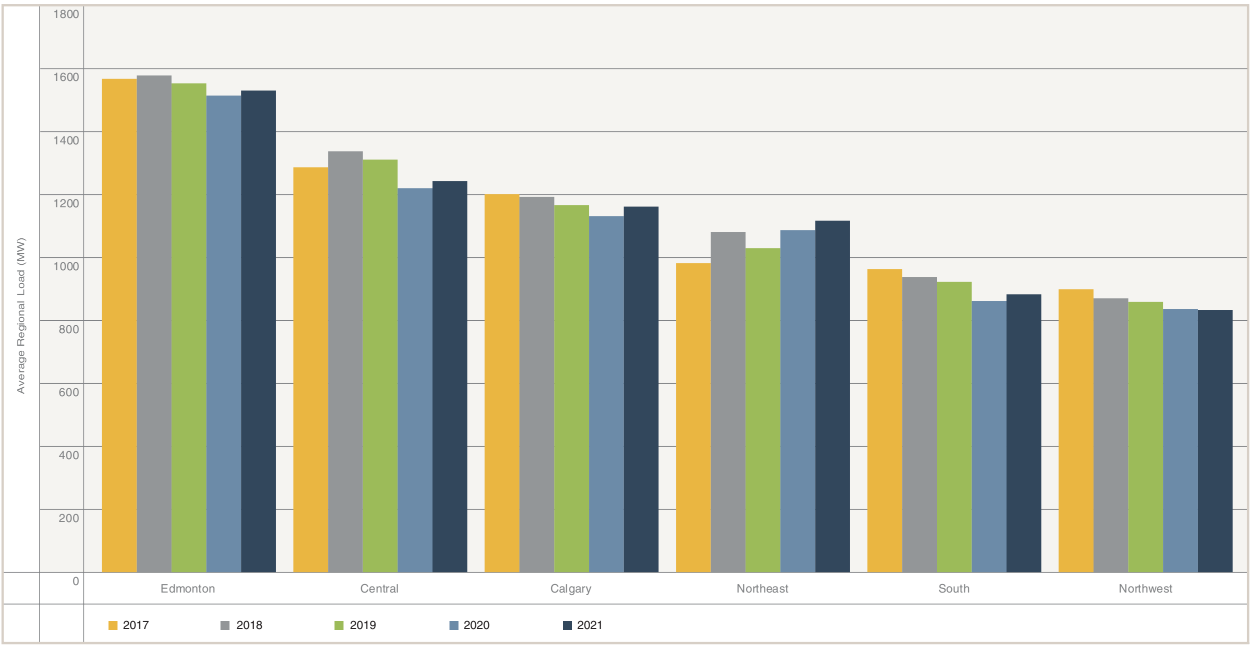
FIGURE 9: Behind-the-Fence load as percentage of AIL



Regional load

Figure 10 shows the average regional system[5] load (i.e., excluding BTF load) over the last five years. Except for the Northwest, all regions had an increase in load for 2021. The Northeast, Calgary and South regions had the highest growth, at 2.8, 2.7, and 2.4 per cent, respectively. The Central region, at 1.9 per cent, and Edmonton, at 1.1 per cent, were next. Finally, the Northwest region lost a small amount of load, down 0.3 per cent year-over-year. However, the growth rates in the Calgary, Edmonton and South regions were inflated by a third or more due to the impacts of extreme weather. On the other hand, growth rates in the Northeast, Northwest, and Central regions, all primarily industrial, saw little difference between actual and weather-normalized load.

FIGURE 10: Regional average load



Installed generation

Year-end generation capacity increased 5.9 per cent

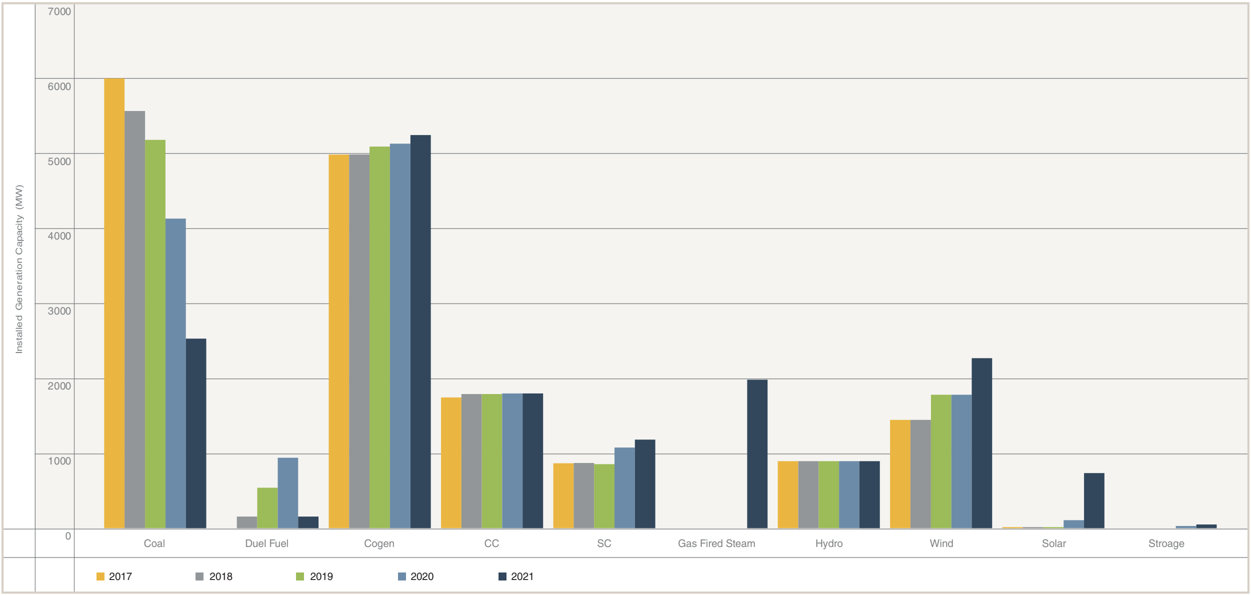
At the end of 2021, installed generation capacity[6] increased to 17,224 MW from 16,270 MW at the end of 2020, an increase of 954 MW or 5.9 per cent. There was 1,254 MW of new generation installed, consisting of 629 MW of solar, 488 MW of wind, 116 MW of cogeneration, 20 MW of storage and 1 MW of other. Installed coal generation fell to 2,530 MW, down from 6,003 MW in 2017. Roughly 1,200 MW of 2020 coal generation (Keephills 2, Sundance 6, and Sheerness 1) converted to gas-fired steam generation in 2021. The other 400 MW, Sundance 5, was retired. In addition, 785 MW of dual-fuel assets[7] (Sheerness 2 and Battle River 5) converted to gas-fired steam. At the end of 2021, purely gas-fired generation was 59 per cent of Alberta's installed generation capacity. Coal-fired generation, including dual fuel, was 16 per cent, down from 37 per cent in 2017. Figure 11 shows the installed capacity of each fuel type at the end of each of the last five years.

[5] The definition of the regions can be found in the document at this link: https://www.aeso.ca/assets/Uploads/Planning-Regions.pdf.

[6] From the AESO's perspective, a unit's capacity is considered installed when its transmission connection becomes active. The active operation of the unit may lag the connection date.

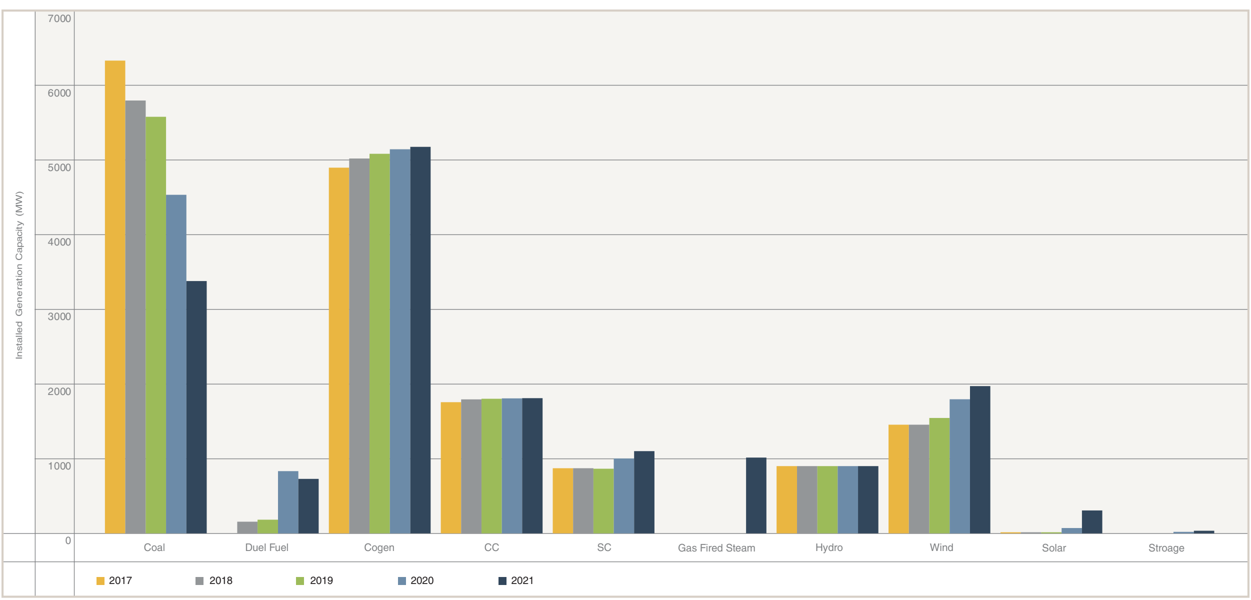
[7] Battle River 4 & 5 and Sheerness 2 converted to dual fuel prior to 2021 but had been classified as coal in previous reports. They have been reclassified as dual fuel in this report.

FIGURE 11: Year-end generation capacity by technology



While not as significant as the year-end capacity, 2021 had an increase in the average annual installed generation capacity. During the year, installed capacity averaged 16,699 MW, compared to 16,380 MW in 2020, for an increase of 1.9 per cent. The main driver for the increase was the installation of several wind and solar farms throughout the year. Figure 12 shows the changes in the average annual capacity of each technology type.

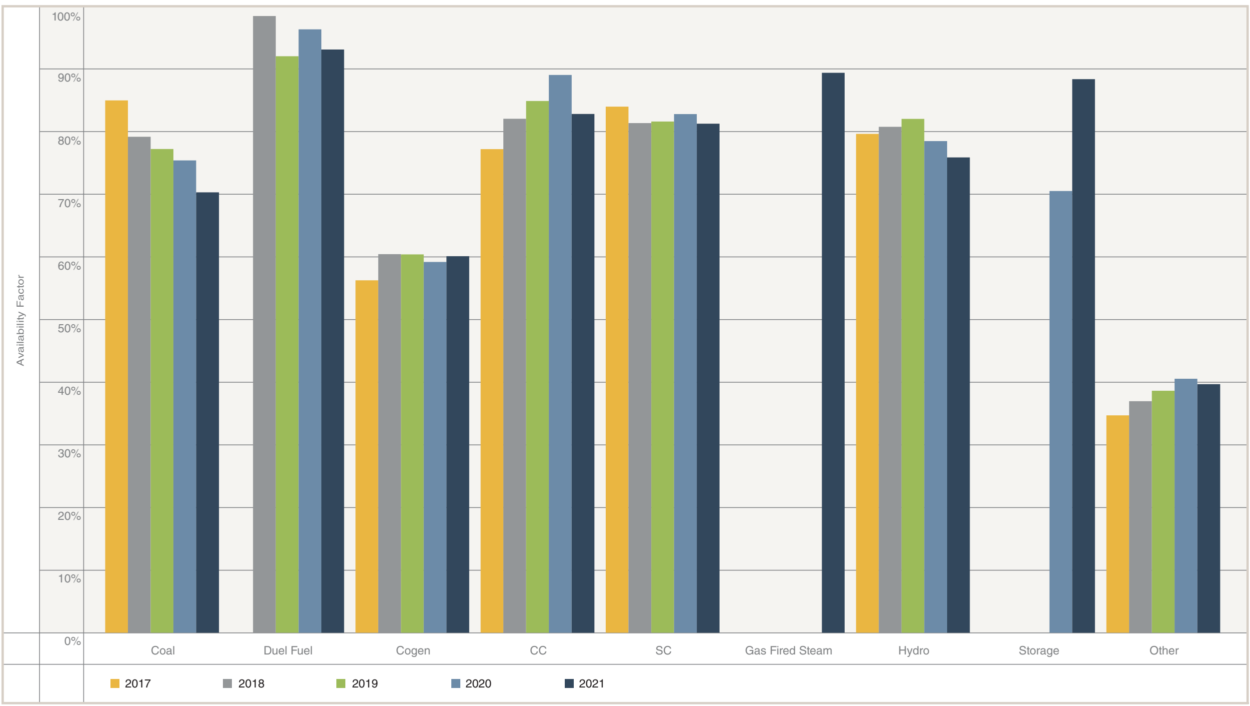
FIGURE 12: Average annual generation capacity by technology



Generation availability

The availability factor is the average percentage of installed generation capacity 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 and solar generation are excluded from this calculation as their available capacity is dependent on environmental factors. All available generation from wind and solar is used to supply demand, which is not true of other technologies. Since it is not available to the energy or ancillary services markets, any generation used to self-supply behind-the-fence load is excluded from available energy volume, but the installed capacity is included in the generation capacity volume. Figure 13 illustrates the annual average availability factor by generation technology. Availability of coal-fired generation fell this year due to outages related to the conversion of some units to gas-fired steam.

FIGURE 13: Annual availability factor by technology



Coal technology had the highest utilization factor

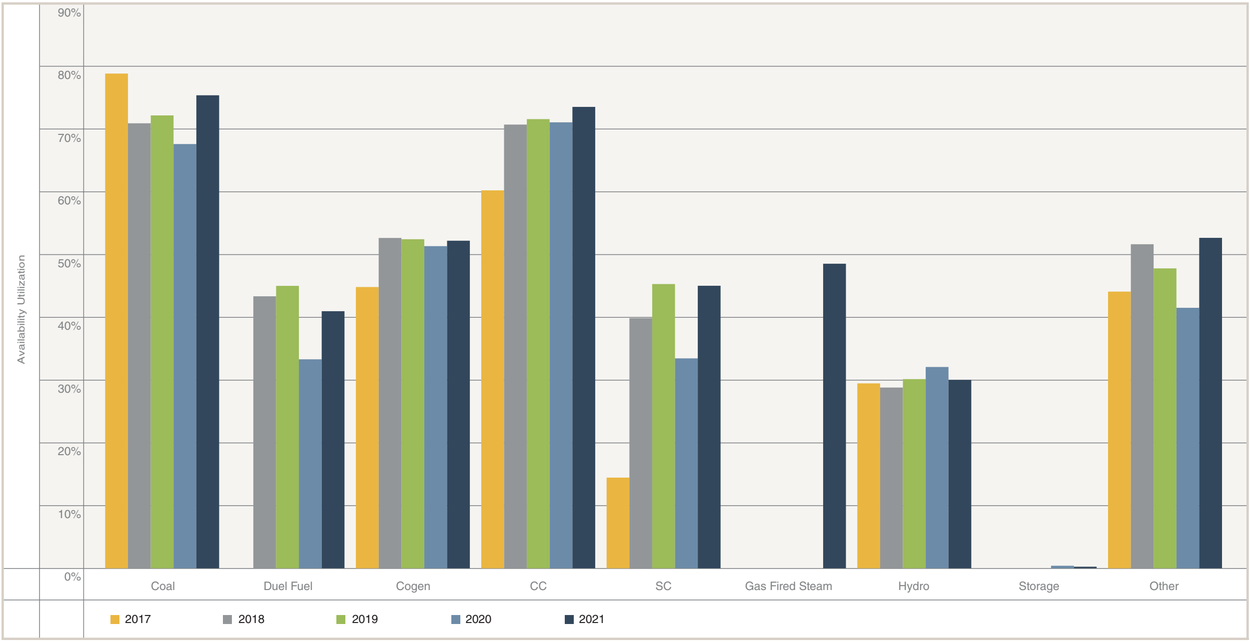
Availability utilization represents the percentage of the available power that was dispatched to serve load. Availability utilization is calculated as the ratio of net-to-grid generation to net-to-grid available capacity. Capacity and generation used to supply behind-the-fence load has been excluded from the availability utilization calculation. Wind and solar generation are excluded from this calculation since all available wind and solar power is fully utilized, except in rare circumstances. Figure 14 illustrates the annual availability utilization by generation technology.

Prior to 2018, the availability utilization of coal-fired generation was consistently highest among dispatchable generation technologies.[8] Starting in 2018, the combination of lower gas prices and higher carbon costs, which had a bigger impact on coal-fired generation, led to combined-cycle gas generation replacing coal-fired generation as the lowest cost—and therefore the most utilized—generation technology. However, in 2021, coal-fired generation rebounded to again have the highest utilization of all the dispatchable generation technologies. This was a result of higher-cost coal units converting to other technologies, leaving mostly efficient coal-fired generation in operation.

Despite being a relatively low-cost option, the availability utilization of cogeneration gas is less than that of other thermal generation. This relationship exists because cogeneration gas is used mainly as on-site generation at industrial facilities to serve on-site load, thus is less responsive to gas and power prices.

[8] Dispatchable technologies refer to non-variable generation resources which can be dispatched up or down to follow load regardless of environmental conditions.

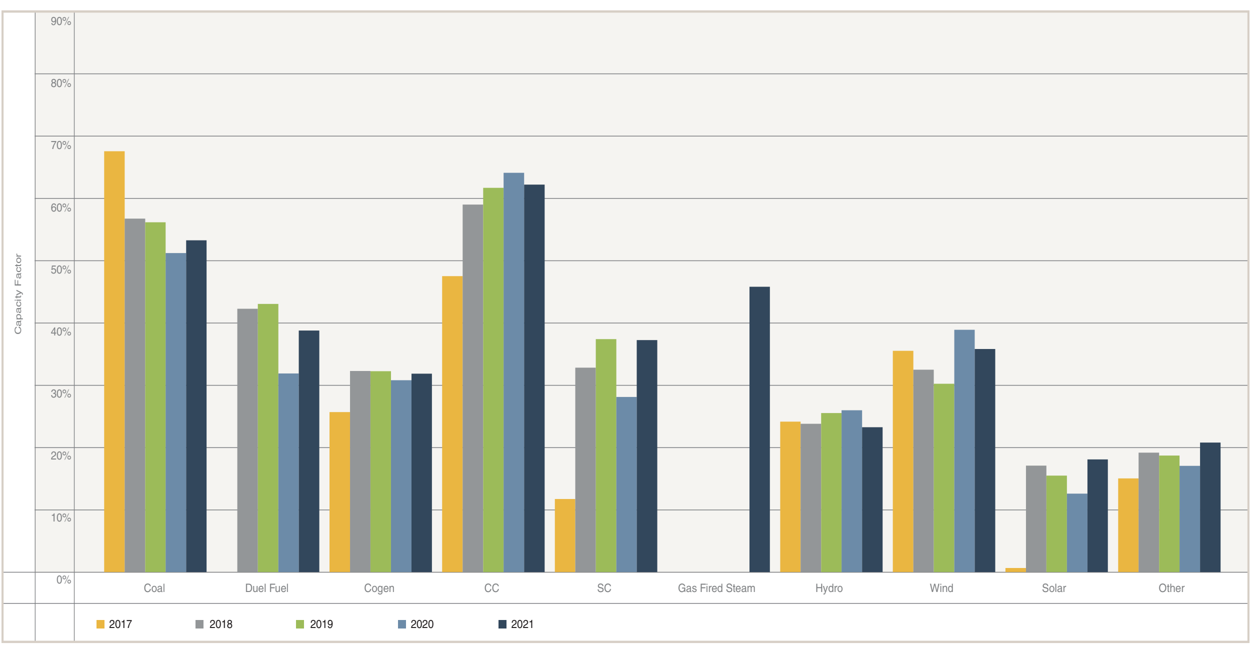
FIGURE 14: Annual availability utilization factor by technology



Combined-cycle generation capacity factor remains the highest

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 average net-to-grid generation to the maximum capability over the given year. The power used to serve on-site load is excluded from the calculation of the capacity factor. As a result, the capacity factor measure underreports the output of cogeneration gas technology. Figure 15 illustrates the annual capacity factor by generation technology.

FIGURE 15: Annual capacity factor by technology



Like the comments in the above sections, the combination of higher carbon costs and lower gas prices has altered the capacity factors of various technologies since 2018. The capacity factor of coal-fired generation has fallen from just under 70 per cent to 53 per cent, as higher carbon costs increased the technology's price. In contrast, lower gas prices led to increased capacity factors of both combined-cycle and simple-cycle gas units. Combined-cycle units have replaced coal-fired units as the technology with the highest capacity factors, reflecting the lower cost of combined-cycle generation. The capacity factor of combined-cycle was 62 per cent—on average, meaning for every 100 MW of installed capacity, combined-cycle generation delivered 62 MWh to the AIES each hour.

Gas generation supplied 54 per cent of net-to-grid energy

Figure 16 illustrates the average net-to-grid generation from each generation technology over the past five years. In 2021, coal-fired generation, including dual-fuel assets, supplied 31 per cent of the energy delivered to the AIES, down from 59 per cent in 2017. Pure gas-generation technologies delivered 54 per cent of net-to-grid generation, up from 30 per cent in 2017. It's important to note that gas-fired generation is under reported due to the conversion of some coal units to dual-fired gas and coal units. Unfortunately, the AESO does not have access to the amount of each fuel type being used at these dual-fired units and is unable to estimate the amount of gas being used. Renewable generation (hydro, wind and solar) provided 14 per cent, up from 10 per cent in 2017. Wind generation provided the majority of energy from renewable sources. In 2021, 10 per cent of total net-to-grid generation was provided by wind power, a similar output to 2020, but up from the average of seven per cent for 2017-2019.

FIGURE 16: Annual average net-to-grid generation by technology

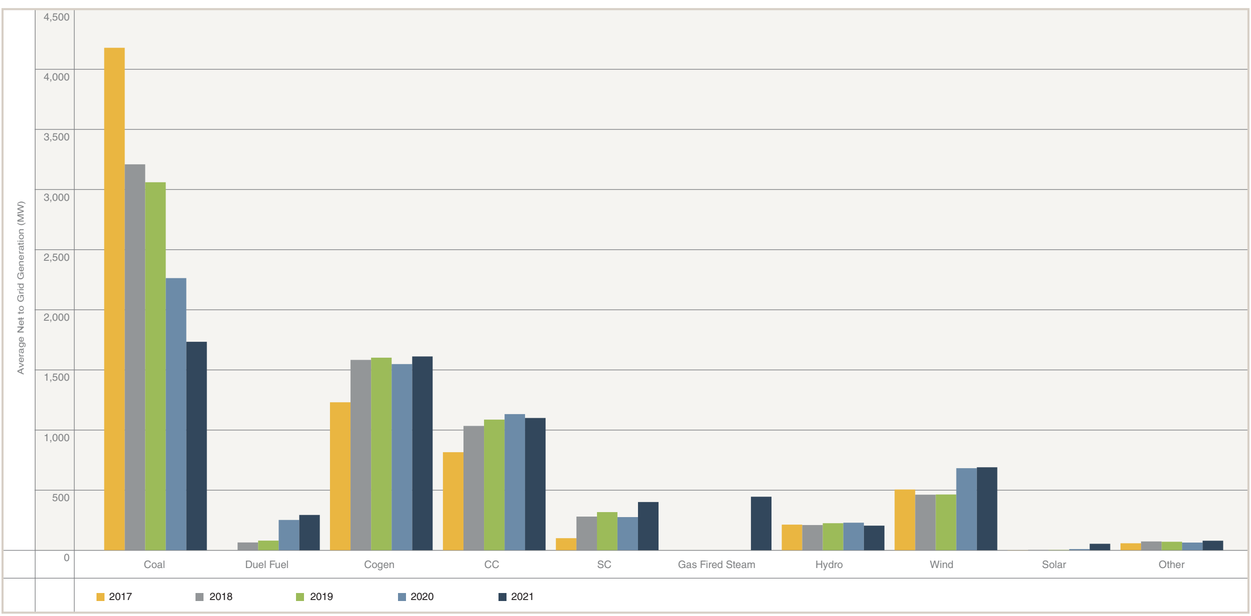
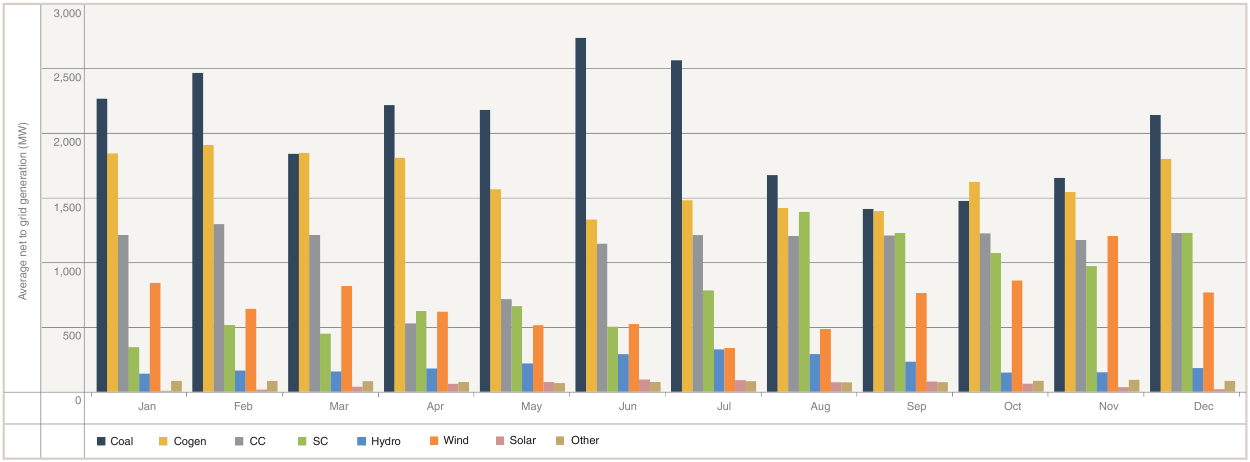


Figure 17 illustrates the monthly average net-to-grid generation from each generation technology over the past year. For the purposes of readability, dual fuel is grouped with coal, gas-fired steam with simple cycle, and storage with other. Seasonal patterns in generation are evident in this figure. Hydro generates more energy during spring-summer time, which also increases imports from WECC counterparties, and wind has higher output during winter months. Coal-fired generation usually declines during the shoulder months (i.e., March to April and September to October). Maintenance outages at coal-fired units are usually scheduled during these times of the year, as load is relatively lower and, since gas generation is cost competitive, there is less need to dispatch coal energy in the merit order. In latter part of 2021, a number of plants completed the conversion to purely gas plants, reducing the amount of coal generation.

FIGURE 17: 2020 monthly average net-to-grid generation by technology



Achieved premium to pool price

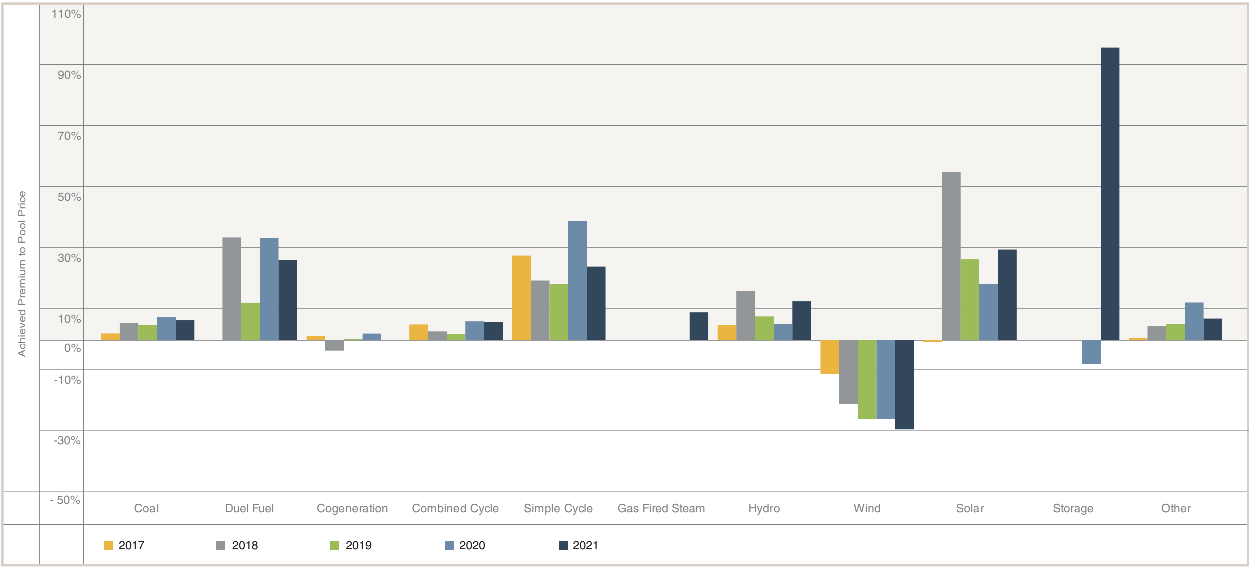
The offered price of power dictates a unit's position in the merit order which, in turn, determines whether system controllers will dispatch the unit to run. Market participants choose offer prices based on the operational characteristics of the unit, the price of fuel, and other economic considerations of the unit operator. Low-cost baseload generation technologies typically adopt a price-taker strategy: they offer energy to the market at a low price (usually $0/MWh) to ensure dispatch and will produce energy in a majority of hours. Higher-cost peaking generation or fuel-limited technologies typically offer energy at a higher price and only produce energy when strong demand drives the pool price higher. In the Alberta market, a range of technologies also employ a scarcity-pricing approach for all, or a portion of the unit, to reflect higher value for energy during tighter supply demand balance conditions.

Achieved price represents the average price realized in the wholesale energy market for electricity delivered to the grid and is calculated as the weighted average of the hourly pool price, where the price in each settlement interval is weighted by the net-to-grid generation in that interval. The combination of offer strategy, market conditions and dispatched volumes determines the achieved price that each asset type receives. The achieved margin represents the difference between the achieved price and the average pool price over the year.

Figure 18 illustrates the achieved premium-to-pool price realized by each generation technology over the past five years. The achieved premium-to-pool price is calculated as the ratio of the achieved margin to the average pool price for each year. 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 i.e., 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 and availability on the average revenue per unit of energy delivered to the grid. Generation technologies that operate at a constant level regardless of pool price, such as coal and combined-cycle, would realize achieved premiums around zero. Generation technologies that operate primarily in higher-priced hours, like simple-cycle or solar, would realize positive achieved premiums to pool price, while those that tend to operate in lower-priced hours, such as wind, would realize achieved discounts (or negative achieved premiums) to pool price.

FIGURE 18: Annual achieved premium to pool price



Optimally, baseload generation technologies operate throughout the entire day. These baseload technologies include coal-fired, cogeneration and combined-cycle. For combined-cycle and coal-fired generation, it is more economical to continue operating through low-priced hours than to incur the high cycling 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 2021, combined-cycle and coal-fired technologies realized a six and seven per cent premium to pool price, while cogeneration gas technology was at parity with the pool price. Dual-fuel units, because of their gas component, had more flexibility than pure coal units and achieved a 28 per cent premium.

Peaking-generation technologies achieve greater operational flexibility than baseload generation. The combustion turbines used in simple-cycle gas generation can halt and restart operation without incurring high start-up costs but are less efficient and cost more to operate. These higher costs are reflected in higher offer prices, which positions peaking generation capacity higher 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 a higher average price. Typically, simple-cycle gas generation achieves some of the highest premiums across all generation technologies in Alberta. In 2021, simple-cycle units received a 26 per cent premium to pool price. Battery storage units run in even fewer hours than simple-cycle units. Therefore, they are much more selective of the hours they provide energy, leading to a higher premium. In 2021, storage units achieved a 104 per cent premium to pool price.

Wind generation is the only technology that consistently received 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 with the output of wind power varying according to environmental conditions. In addition, the strongest winds typically occur in the overnight hours, leading to the highest wind production during the lowest priced hours.

When wind blows in a region, all available 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 higher-priced generating units in the energy market merit order. Wind generation tends to reduce the system marginal price, which lowers its achieved price. In 2021, wind generation received a 32 per cent discount to the pool price.

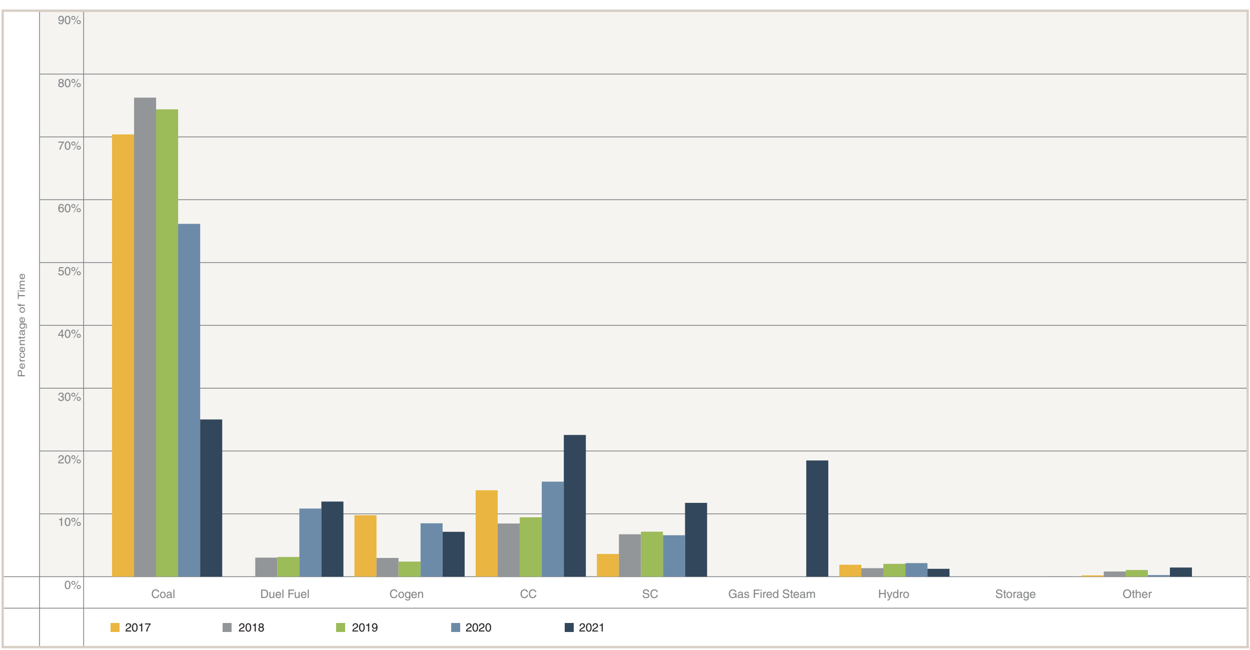
Solar power is like wind power, in that it cannot control its operational schedule because it is dependent on environmental conditions. However, since the highest-priced hours are typically during on-peak hours, when the sun is shining, solar power gets an achieved price premium. In 2021, this premium was 32 per cent.

Hydro units have a mix of offering strategies. Many hydro units are run-of-river and provide generation regardless of the pool price. Other units have a reservoir, allowing some generation to be timed with higher-priced hours. Additionally, environmental conditions, such as spring run-off or low water, may impact the amount of generation at hydro units. In 2021, hydro received a 14 per cent premium to pool price, up from a six per cent premium in 2020.

Gas-fired generation set marginal price in 60 per cent of hours

Figure 19 illustrates how frequently each generation technology sets the system marginal price. For the first time, pure gas-fired generation, which includes combined-cycle, simple-cycle and gas-fired-steam, was on the margin most of the time in 2021, at 60 per cent. This was double the time on the margin in 2020. Meanwhile, coal generation, including dual-fuel assets, was on the margin only 37 per cent of the time, down from 67 per cent of the time in 2020. The decline in coal-fired generation on the margin can be explained by a combination of a number of inefficient units converting to gas or retiring and the remaining, more efficient, units were lower in the offer stack, due to higher prices.

FIGURE 19: Annual marginal price-setting technology



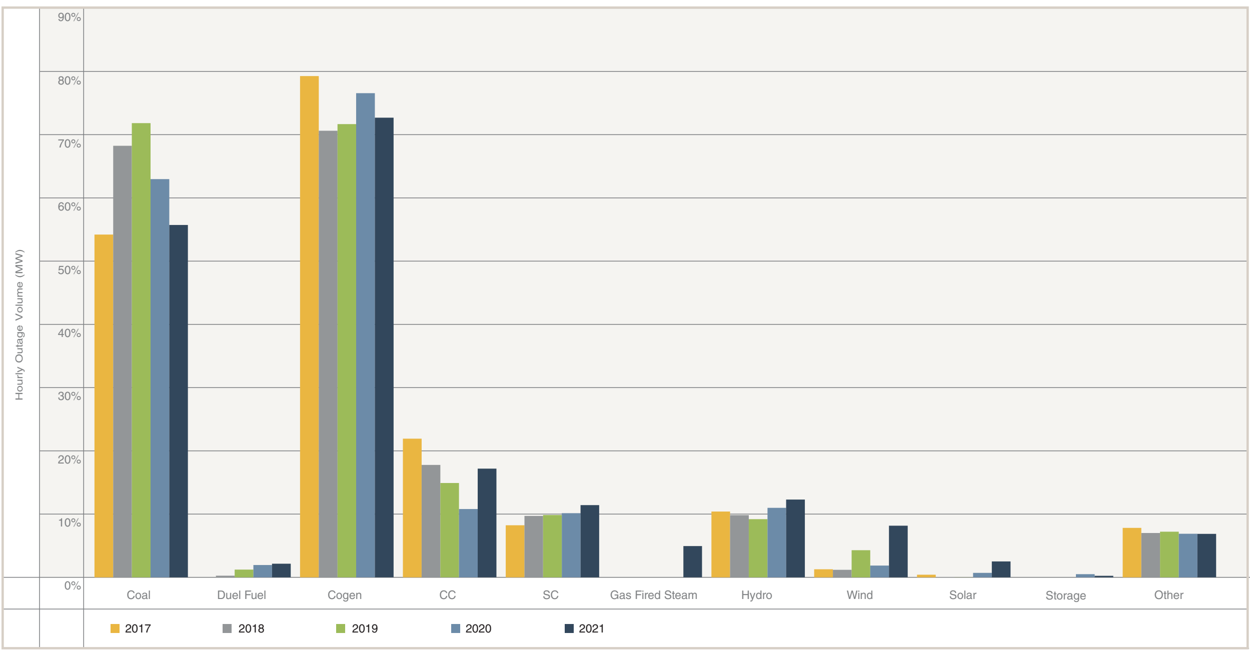
Supply adequacy

Supply adequacy expresses the ability of the system to serve load and system losses. 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.*[9]

Generation outages were 5.9 per cent higher year-over-year

The volume of generation outages is a prime driver of the supply cushion, as they reduce the amount of supply available. Outages are either planned, such as for maintenance, or they can be unexpected, such as a tube leak that forces a generator offline. The volume of an outage is the result of subtracting a unit's available capacity from its maximum capacity available to the bulk transmission system. Any outage that occurs behind-the-fence at a self-supplied site is not included. For the purposes of this calculation, mothballed units are considered on outage. Two units, Sundance 3 and 5, were mothballed in April 2018. This added 368 MW and 406 MW, respectively, to the coal outage totals. Sundance 3 retired at the end of July 2020, while Sundance 5 was suspended at the end of October 2021. Figure 20 shows the average hourly outage volume by technology for the last five years.

FIGURE 20: Annual hourly average generation outages by fuel type

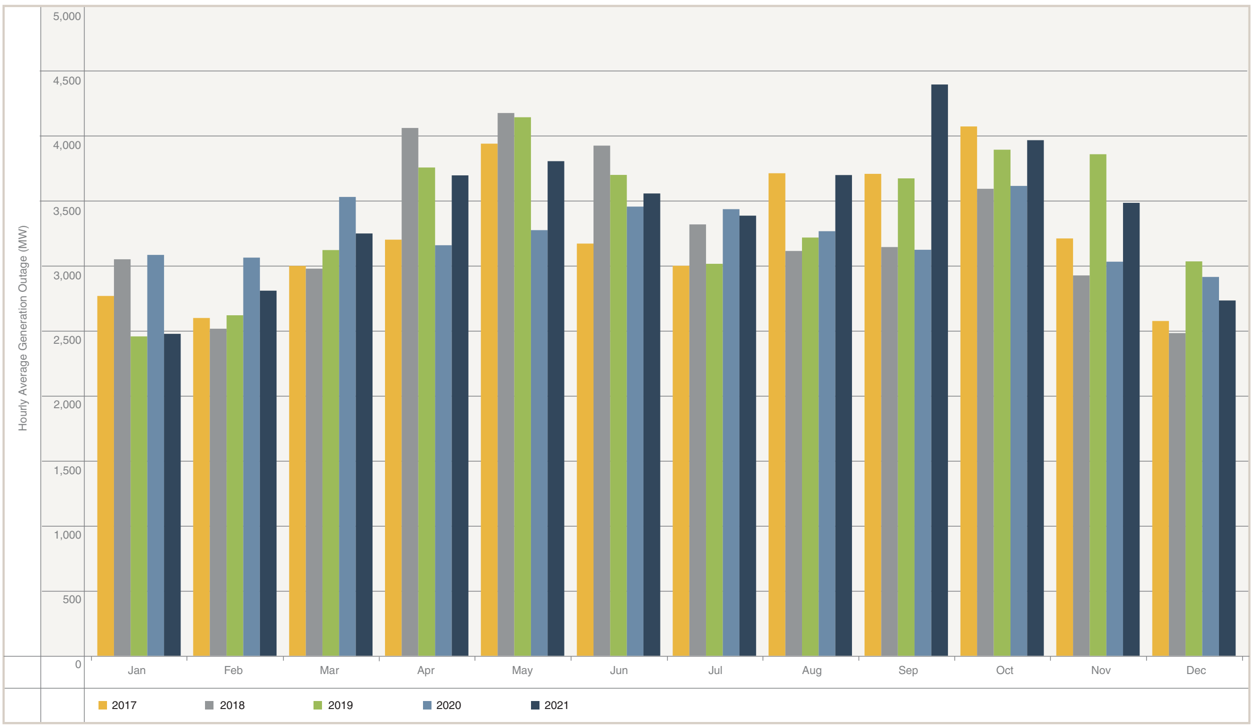


In 2021, excluding the year-over-year impact of Sundance 3 retiring (about 200 MW), the overall average hourly outage volume increased approximately 400 MW compared to 2020. Excluding Sundance 3, hourly average coal outages increased roughly 85 MW per hour year-over-year. The primary cause for this was a longer-than-expected forced outage at Genesee 2. The fact that several units took outages to convert to gas was offset by the lower number of coal units in service by the end of the year. About 88 MW of outages that would have been coal units in the past were gas-fired-steam units in 2021. Outages in combined cycle units were up 113 MW due to a month-and-a-half long turnaround at the Shepard Energy Centre. Wind unit outages were up 112 MW year-over-year due to three new projects that were declared active during the year but unable to provide power right away.

9 https://www.aeso.ca/market/market-and-system-reporting/long-term-adequacy-metrics/

Generation outages are usually seasonal. The highest outages typically occur during the shoulder period from mid-April to mid-June and late-September to early-November. This is usually when load is the lowest and any outages have the least impact. Outages in some of the higher demand months of January to March, July and December were lower year-over-year. However, the planned Shepard outage in April and the unplanned Genesee 2 outage from July to early December had an impact on prices. Figure 21 shows the hourly average generation outage volume by month for the last five years.

FIGURE 21: Generation outages by month



Supply cushion decreased 10 per cent

The hourly supply cushion represents the additional energy in the merit order that remains available for dispatch after load is served. Large supply cushions indicate greater reliability because more energy remains available to respond to unplanned outages or unexpected increases in demand. In 2021, the average supply cushion decreased 10 per cent (or 189 MW) to 1,734 MW from its 2020 value. The main year-over-year differences occurred between April and September, due to higher demand in 2021 compared to the COVID-19 impacted demand in 2020 and more generation outages. The year-over-year difference during these six months was a decrease in the supply cushion of 459 MW. During the other six months of the year, the supply cushion average was on par with the same months in 2020.

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. During a supply shortfall event, the AESO must declare an Grid alert[10] if dispatches have been issued for all operating blocks in the energy market merit order, operating reserves requirements are

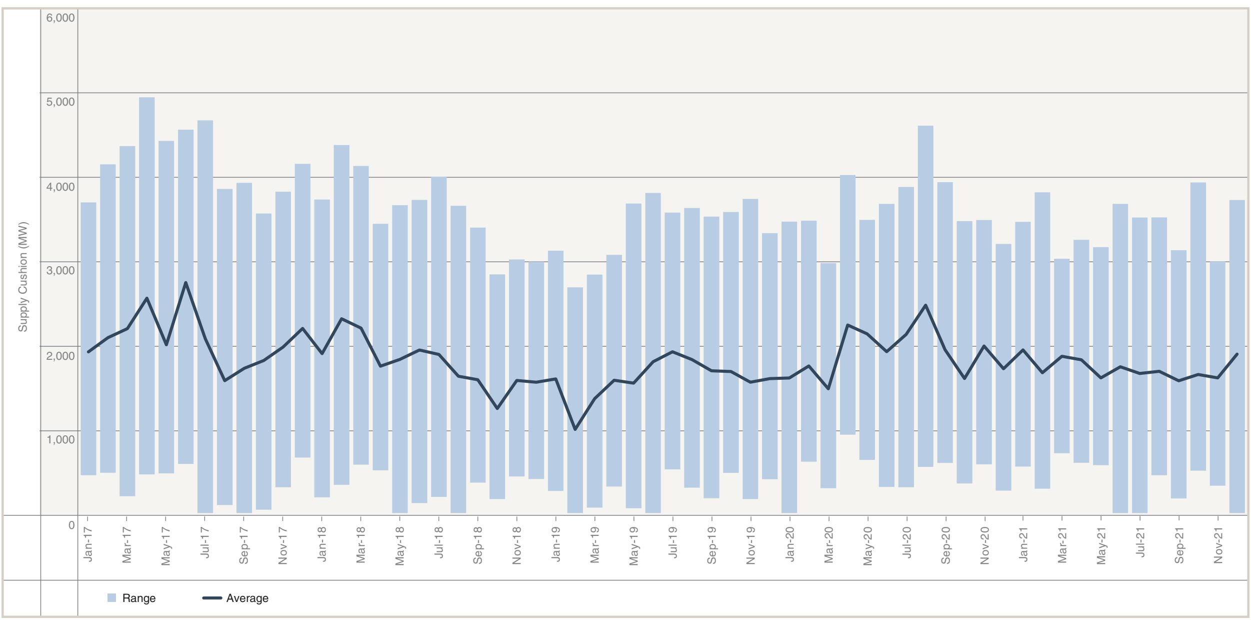
[10] https://www.aeso.ca/rules-standards-and-tariff/iso-rules/section-305-1-energy-emergency-alerts/

being met and the AESO is concerned about sustaining its operating reserves; a Grid alert must be declared when operating reserves are committed to maintain the supply-demand balance while ensuring that the regulating reserve margin is maintained; a Grid alert must be declared if the AESO foresees or has implemented curtailment of firm load.

In 2021, Grid alert events were declared four times. There were three in the summer, on June 29, July 7 and July 14, for a total of 397 minutes. During the June 29 event, the primary cause was high demand, leading to a Grid alert being declared. On July 7 and 14, it was high demand coupled with a generator trip that led to Grid alerts being declared. On Dec 27, a Grid alert event occurred for 341 minutes due to high demand combined with unit outages and significant derates.

Figure 22 shows the monthly average of the supply cushion over the last five years. It also has the range of the supply cushion throughout each month.

FIGURE 22: Monthly supply cushion

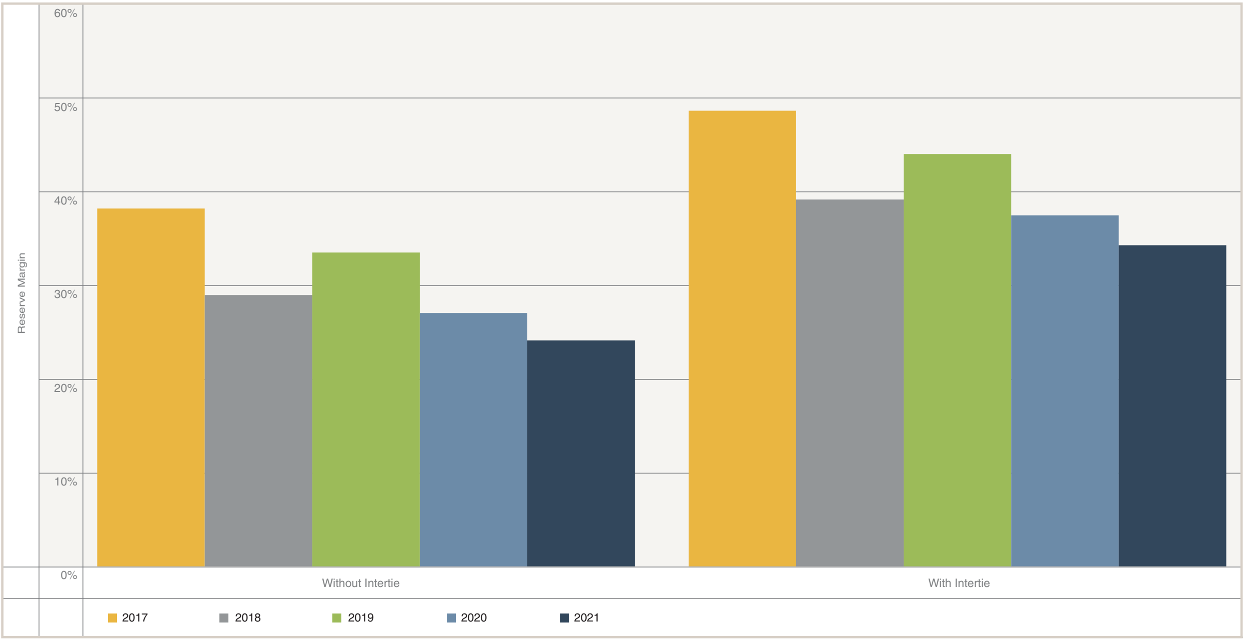


Reserve margin decreased three per cent

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 to evaluate system reliance on generation outside Alberta. In this calculation, the system generation capability excludes wind and solar generation, which may be unavailable, and reduces hydro generation to reflect seasonal variability. Generation capability reflects the installed capacity volumes at the end of the year.

Figure 23 shows the annual reserve margin over the past five years. In 2021, the annual reserve margin was 24 per cent without the intertie and 34 per cent with the intertie. Both metrics were down three per cent compared to 2020. The year-over-year decrease in the reserve margin from was due the combination of roughly 100 MW less installed capacity at year-end and an increase in the peak system load of approximately 250 MW.

FIGURE 23: Annual reserve margin



Wind generation

Wind generation served seven per cent of Alberta internal load

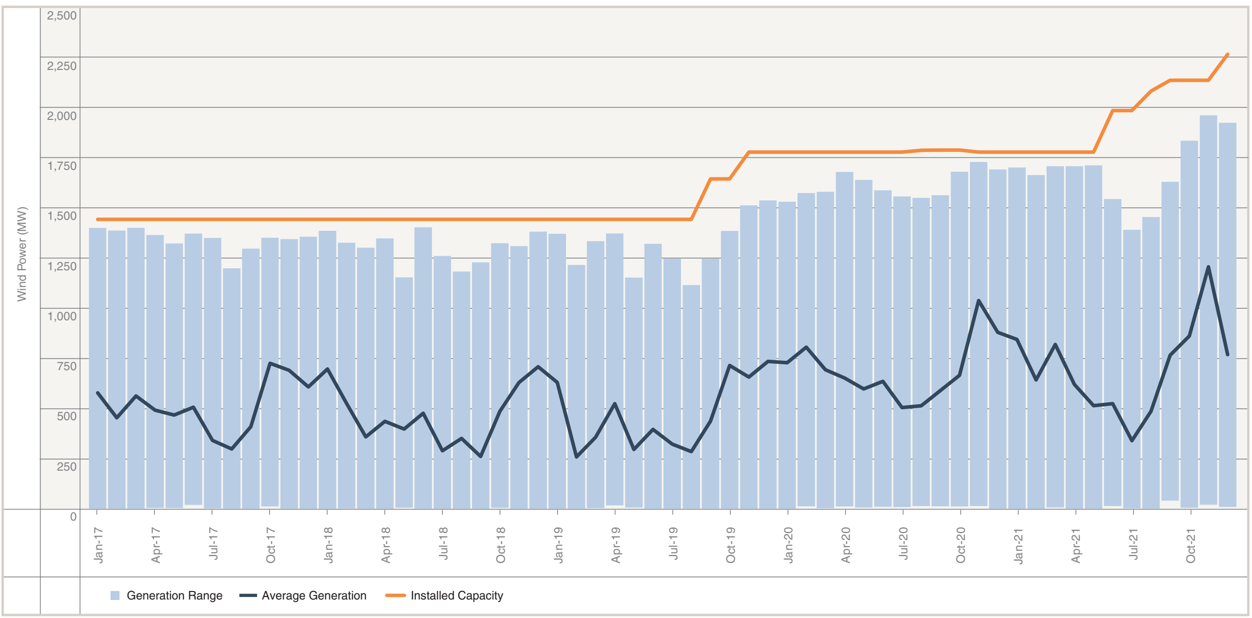
Table 4 summarizes the annual statistics for wind generation. A total of three new wind facilities, with a combined capacity of 488 MW, came online in 2021. This increased the total capacity for wind to 2,269 MW at the end of the year. This represented 11 per cent of the total installed generation capacity in Alberta. Wind generation produced seven per cent of total AIL in 2021, the same as 2020. The capacity factor of wind generation fell to 36 per cent, down from 2020, due to weak generation during summer months. However, this was still higher than any year in the 2017-2019 period.

TABLE 4: Annual wind generation statistics

Year	2017	2018	2019	2020	2021
Installed wind capacity at year end (MW)	1,445	1,445	1,781	1,781	**2,269**
Total wind generation (GWh)	4,486	4,104	4,116	6,079	**6,133**
Wind generation as a percentage of total AIL	5%	5%	5%	7%	**7%**
Average hourly capacity factor	35%	32%	30%	39%	**36%**
Maximum hourly capacity factor	96%	96%	94%	96%	**95%**
Wind capacity factor during annual peak AIL	6%	9%	0%	8%	**16%**

The monthly average of wind generation usually exhibits a seasonal pattern, generally peaking in winter and falling in summer. The maximum hourly wind generation exhibits a weaker seasonal pattern. Strong winds may occur in any month, though they occur more frequently in winter. During extreme weather events, such as a polar vortex in the winter or a heat wave in the summer, wind generation tends to be very weak. This is due to the presence of strong high-pressure weather systems in the wind-generating regions of the province. This results in lower capacity factors during peak-demand periods. Figure 24 shows the installed wind generation capacity and range of hourly wind generation over each month. During summer 2021, average wind generation was weak compared to the other months of the year. The capacity increases in 2021 were: Windrise (June – 207MW); Whitla 2 (in two stages, August and September – 151 MW); and Rattlesnake Ridge (December – 207MW). A new record for monthly average wind generation was set in November 2021, at 1,208 MW.

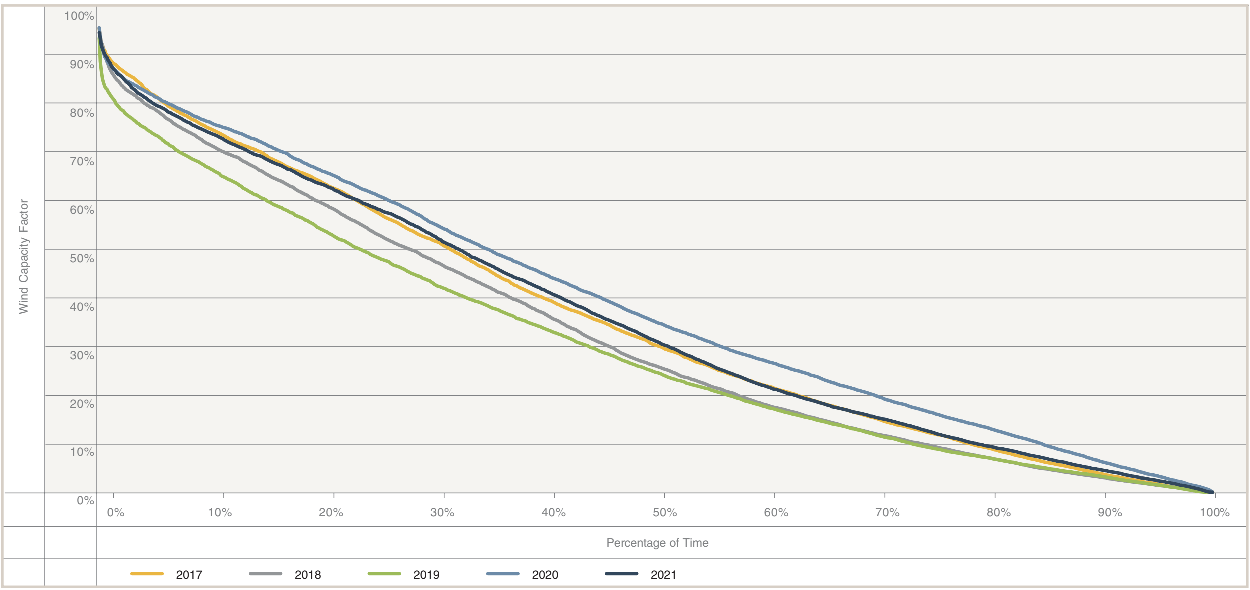
FIGURE 24: Monthly wind capacity and generation



Wind capacity factor decreased

Figure 25 illustrates annual duration curves for the hourly capacity factor for Alberta wind generation. Capacity factor represents the percentage of installed capacity used to generate electricity that was delivered to the grid. The duration represents the percentage of time that capacity factor of wind generation equals or exceeds a specific value.

FIGURE 25: Annual wind capacity factor duration curves

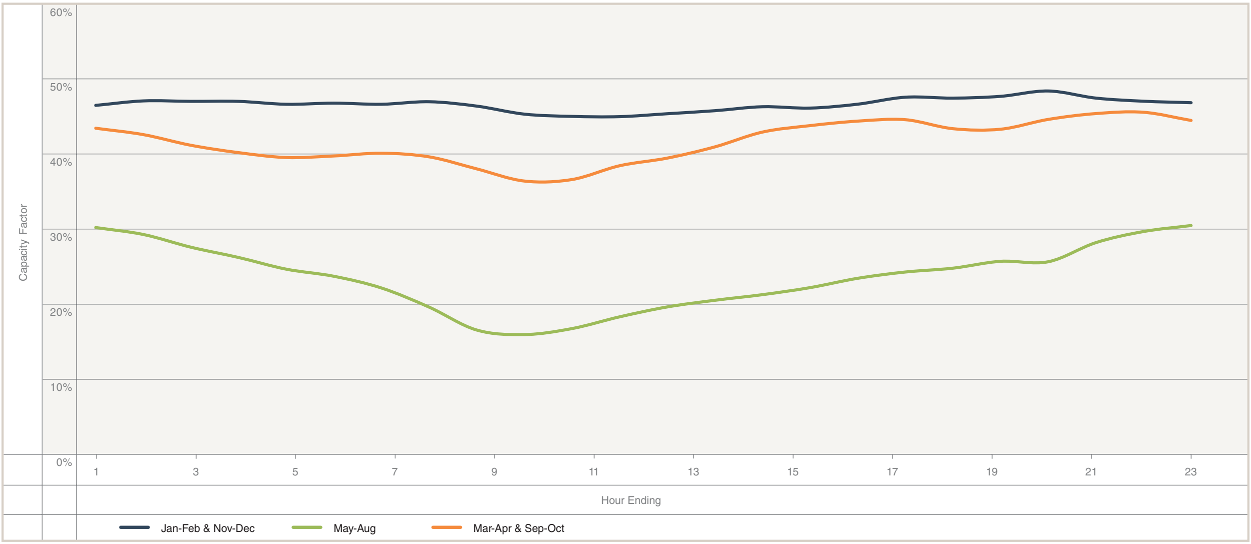


The duration curve for the capacity factor of wind generation decreased in 2021. The capacity factor of wind generation averaged 36 per cent for 2021, which is a three per cent decrease from 2020. A key reason for the lower capacity factor can be attributed to minimal output from the new wind farms for several months after they were declared in-service. For example, Whitla 2 was declared online in late August, but it didn't fully come online until mid-October. Another reason for the lower capacity factors was the presence of low wind conditions for a much of the June to August period, as well as in the latter half of December.

The capacity factor—the ratio of net-to-grid generation to installed capacity—for wind generation is comparable to that of simple-cycle gas generation; however, unlike gas generation, wind generation depends on environmental factors and cannot be dispatched to run when wind is unavailable.

Figure 25 shows average hourly capacity factor of wind generation for different seasons of the year during 2021. It shows that wind generation is typically highest in the overnight hours and lowest in the late morning, with this phenomenon more pronounced in the summer than the winter. The capacity factor of wind ranged from 10 to 25 per cent higher in the winter than the summer.

FIGURE 26: 2021 wind generation seasonal average hourly output



Regional wind

Wind generation in the province was located exclusively in southern Alberta until early 2011. Since 2011, the addition of four wind facilities in central Alberta has increased the geographic diversification of wind generation.

At the end of 2021, wind generation capacity totaled 2,008 MW in southern Alberta and 261 MW in central Alberta. For 2021, the Wintering Hills asset was reclassified to be in the South region from the Central region.

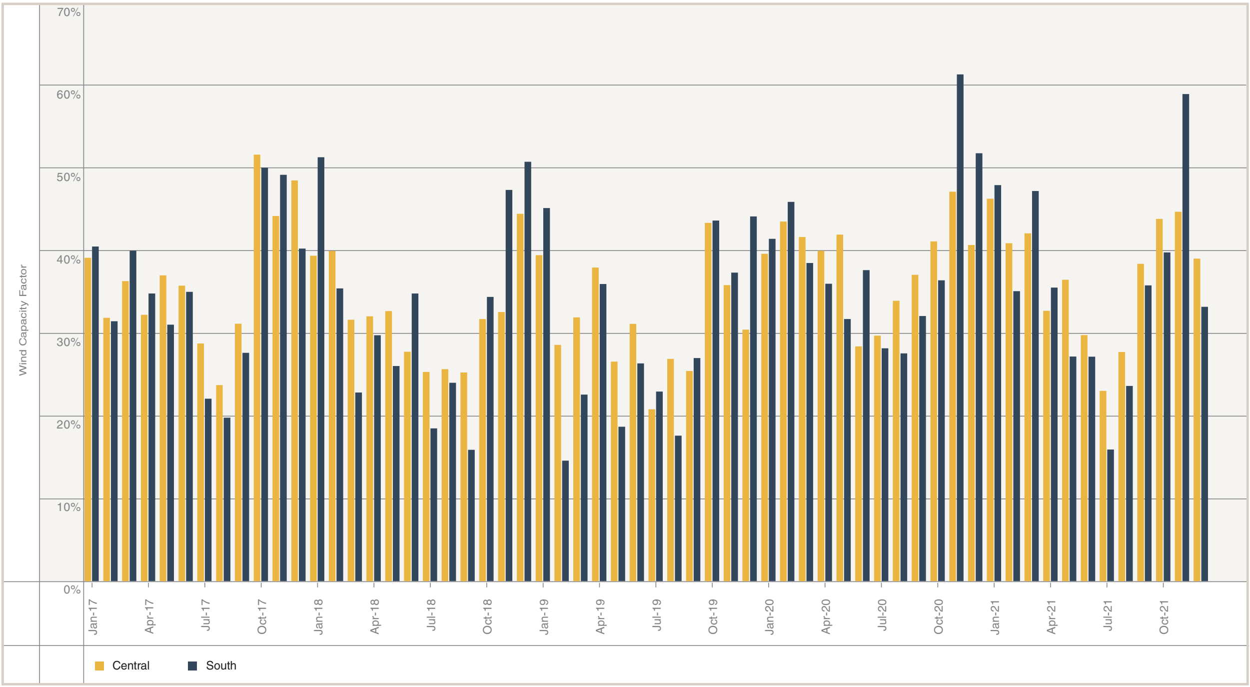
Table 5 shows regional wind generation statistics for 2021. The average capacity factor was the same for both regions, but the achieved price for Central wind exceeded those facilities in the South region. For each megawatt of installed capacity, a wind farm in central Alberta generated roughly the same energy as a wind farm in southern Alberta. However, over the year, for each unit of energy generated, Central wind generation earned more revenue than South wind generation.

TABLE 5: 2021 regional wind statistics

Region	Central	South	Total
Installed wind capacity at year end (MW)	261	2,008	**2,269**
Total wind generation (GWh)	822	5,311	**6,133**
Average wind capacity factor	36%	36%	**36%**
Achieved price ($/MWh)	$80.98	$67.70	**$69.48**

Figure 27 shows the monthly average capacity factor by region in the past five years. In November, the South region had an average capacity factor of nearly 60 per cent and was second only to November 2020 for the highest average capacity factor over the last five years. As can be seen in the monthly profiles, wind tends to be most productive from October through April and least productive in the summer months.

FIGURE 27: Monthly wind capacity factor by region



Solar generation

During 2021, eight new solar farms joined the generation fleet, adding 629 MW of new capacity. The transmission connection of the largest solar farm, Travers at 400 MW, was declared active near the end of December, but the unit did not provide any energy to the grid during the year. Like the wind assets, it can take up to a couple months after the transmission connection being declared active before there is any consistent output from new solar assets. Figure 27 illustrates the monthly average on-peak generation of the solar fleet for 2021 and 2020.

FIGURE 28: Monthly average on-peak output of solar fleet

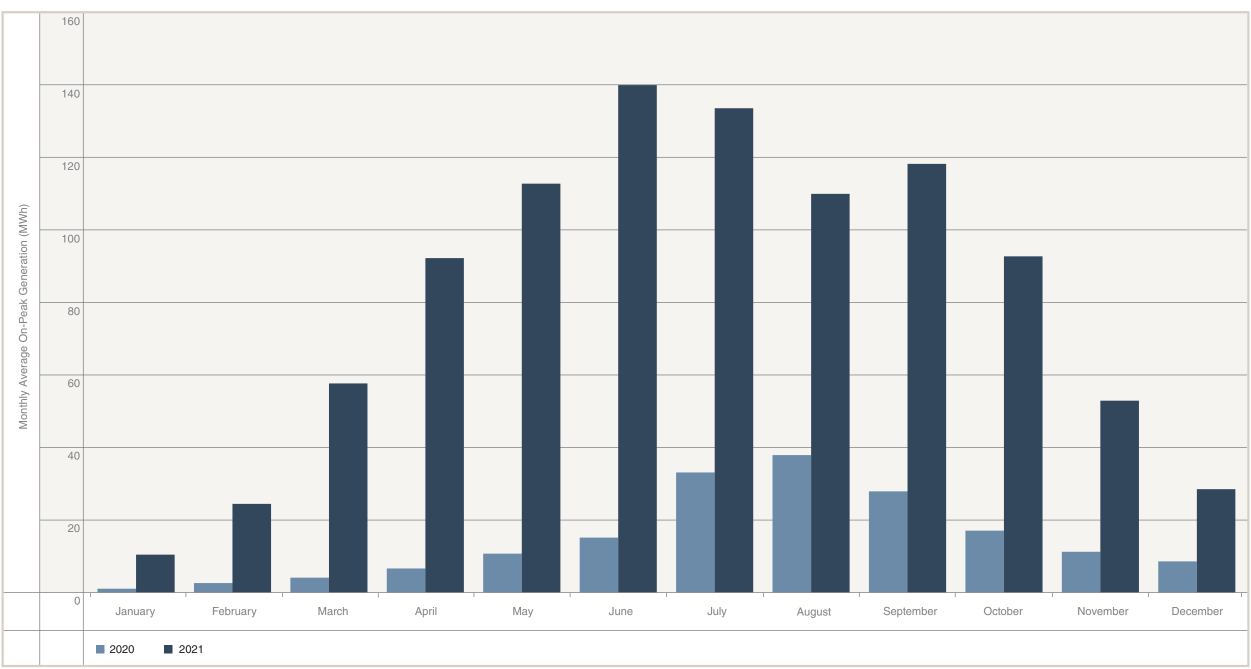
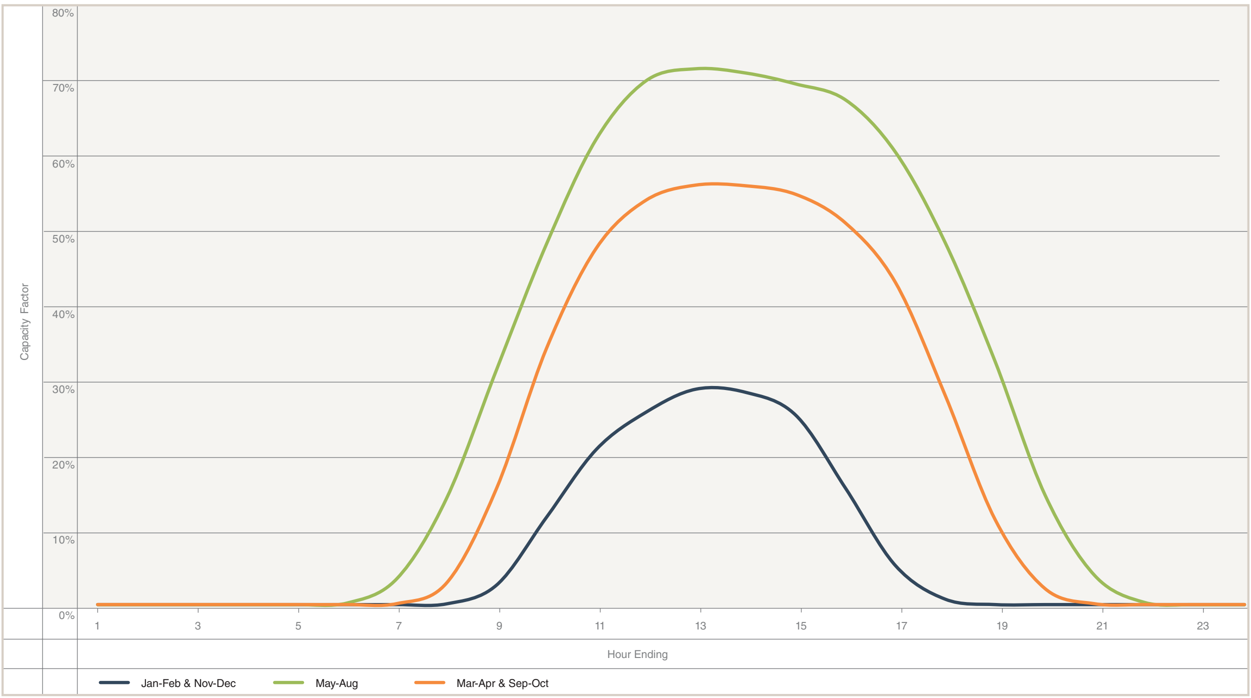


Figure 29 shows average hourly output of solar generation for different periods of the year during 2021. Peak generation occurs between 10 a.m. to 3 p.m., with the summer and shoulder months seeing a couple of extra hours of peak generation in the afternoon. Solar asset capacity factors are 40 to 45 per cent higher in the peak summer hours than in the winter.

FIGURE 29: 2021 seasonal average hourly output of solar fleet



Imports and exports

Alberta transfers electric energy across interties with three neighbouring jurisdictions: B.C., Montana, and Saskatchewan.

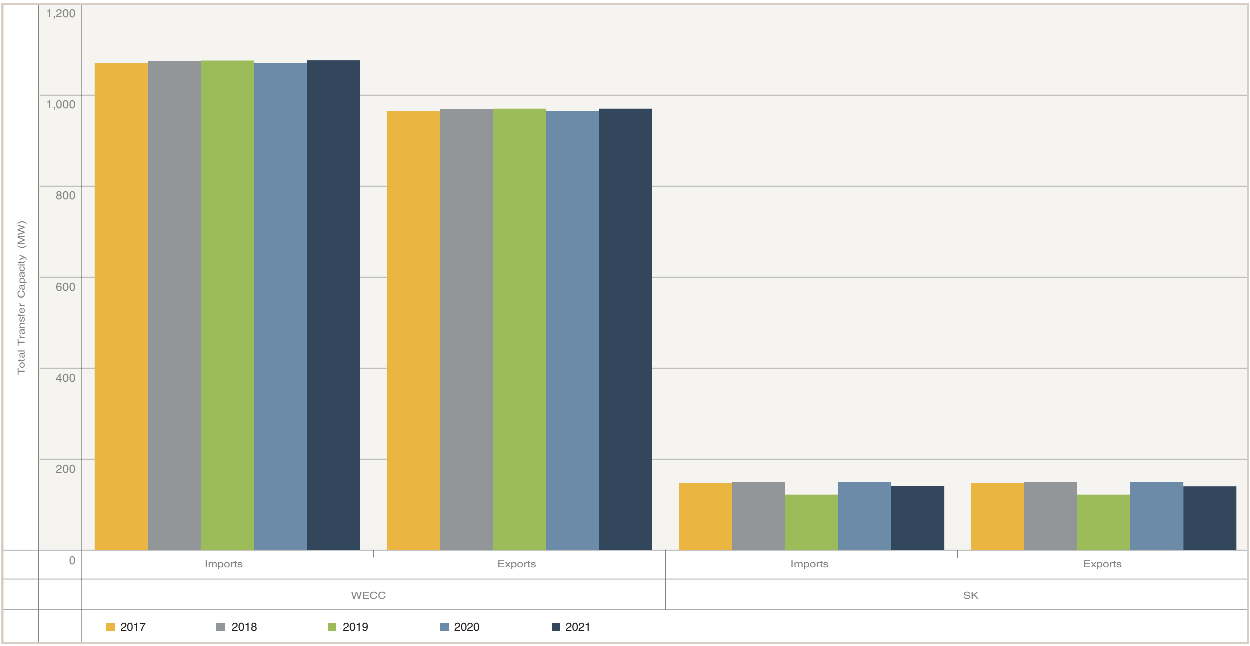
Transfer path rating remained stable

The total transfer capability (TTC) rating is the amount of physical power that can reliably flow across defined paths under specified system conditions. It is estimated based on the physical properties of the interties at the time power is to be flowed. Generally, the TTC is stable over time. However, yearly averages can vary slightly due to the duration of outages that occur.

Alberta, B.C., and Montana are members of the Western Electricity Coordinating Council (WECC) region while Saskatchewan is not. The total power that can flow between Alberta and other members of the WECC region is expressed as a combined TTC, calculated as the sum of the TTC of the two individual interties that connect Alberta to B.C. and Montana.

Figure 30 shows the average TTC in each year between Alberta and other WECC members, and between Alberta and Saskatchewan. The TTC remained largely unchanged between 2020 and 2021, with differing maintenance schedules accounting for the year-over-year differences.

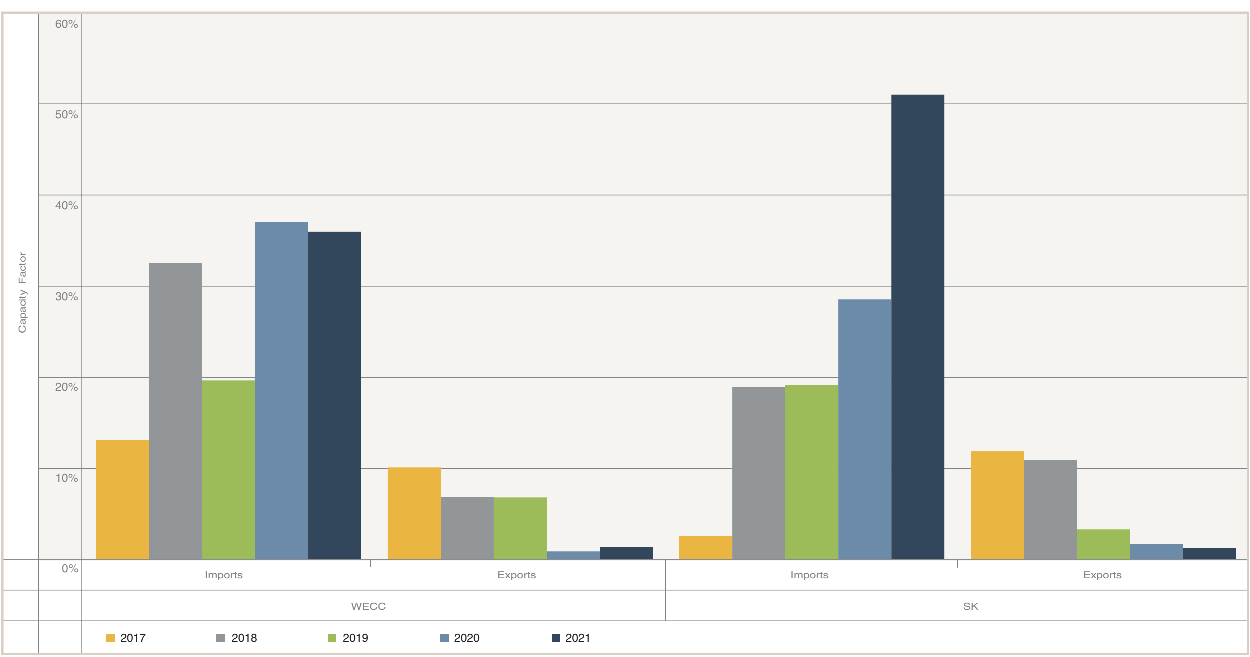
FIGURE 30: Annual path rating by transfer path



Saskatchewan import capacity factor highest in last 5 years

Capacity factor represents the percentage of the TTC that was used to transfer energy between jurisdictions. The capacity factor is calculated as the ratio of total scheduled energy to the TTC. In 2021, imports from Saskatchewan increased significantly, relative to 2020, resulting in a higher capacity factor. This was a result of the higher prices in Alberta, relative to Saskatchewan, during the year. On the other hand, those higher prices meant that export capacity factors for both WECC and Saskatchewan remained low. Figure 31 illustrates the annual capacity factor for transfers between Alberta and other WECC members, as well as between Alberta and Saskatchewan.

FIGURE 31: Annual capacity factor by transfer path

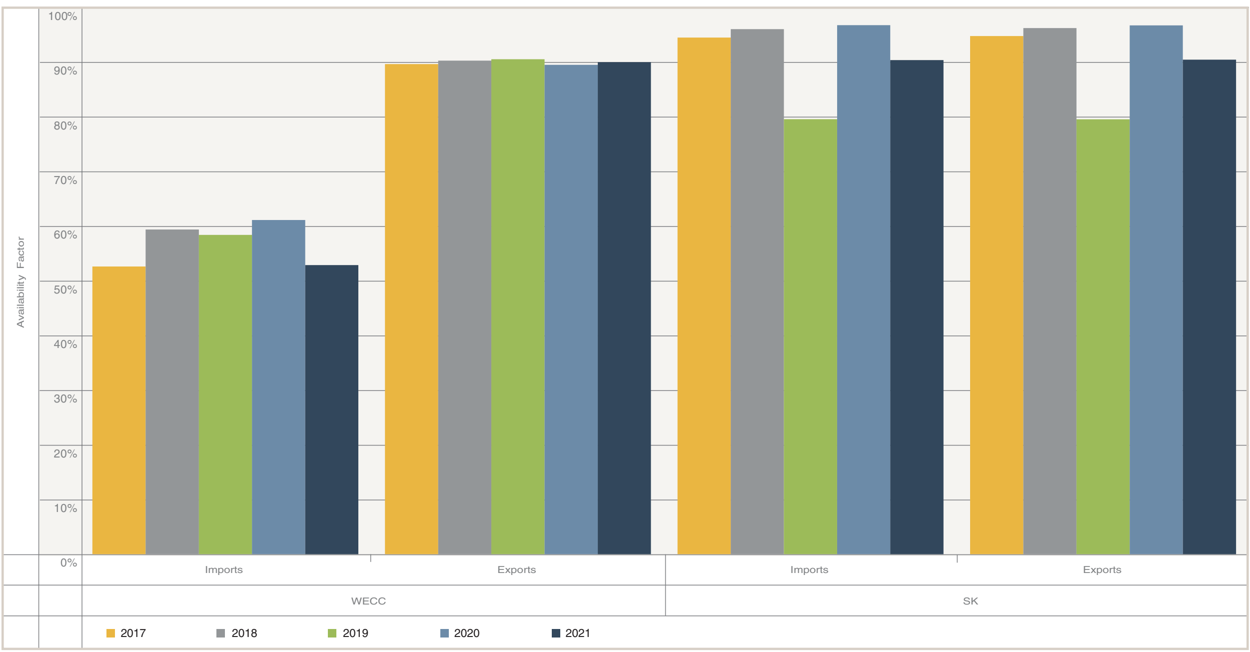


Intertie availability factor

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 system operating limit specifies the maximum import and export capability between Alberta and all neighbouring jurisdictions. A combined operating limit on the B.C. and Montana interties further restricts the transfer capability of total energy transfers between Alberta and other WECC members.

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 TTC. Figure 32 illustrates the annual availability factor for transfers between Alberta and other regions. In 2021, the WECC intertie had a reduced availability factor compared to 2020 primarily due to the lower availability of volume from Load Shed Service for imports (LSSi) contracts.[11] On the Saskatchewan intertie, a long-term maintenance outage reduced the availability factor.

FIGURE 32: Annual availability factor by transfer path



Availability utilization

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 33 illustrates the annual availability utilization for energy transfers between Alberta and other WECC members, and between Alberta and Saskatchewan. In 2021, import utilization increased seven per cent from 2020 levels between Alberta and WECC, and increased 23 per cent on the Saskatchewan transfer path. The export utilization rate remained weak along both the Saskatchewan and WECC transfer paths. Higher power prices in Alberta, relative to the surrounding jurisdictions, was the main reason for both the increase in imports and the weak exports.

[11] Load Shed Service for imports (LSSi) is a transmission system reliability product. See https://www.aeso.ca/market/ancillary-services/load-shed-service-for-imports/ for details.

FIGURE 33: Annual availability utilization by transfer path

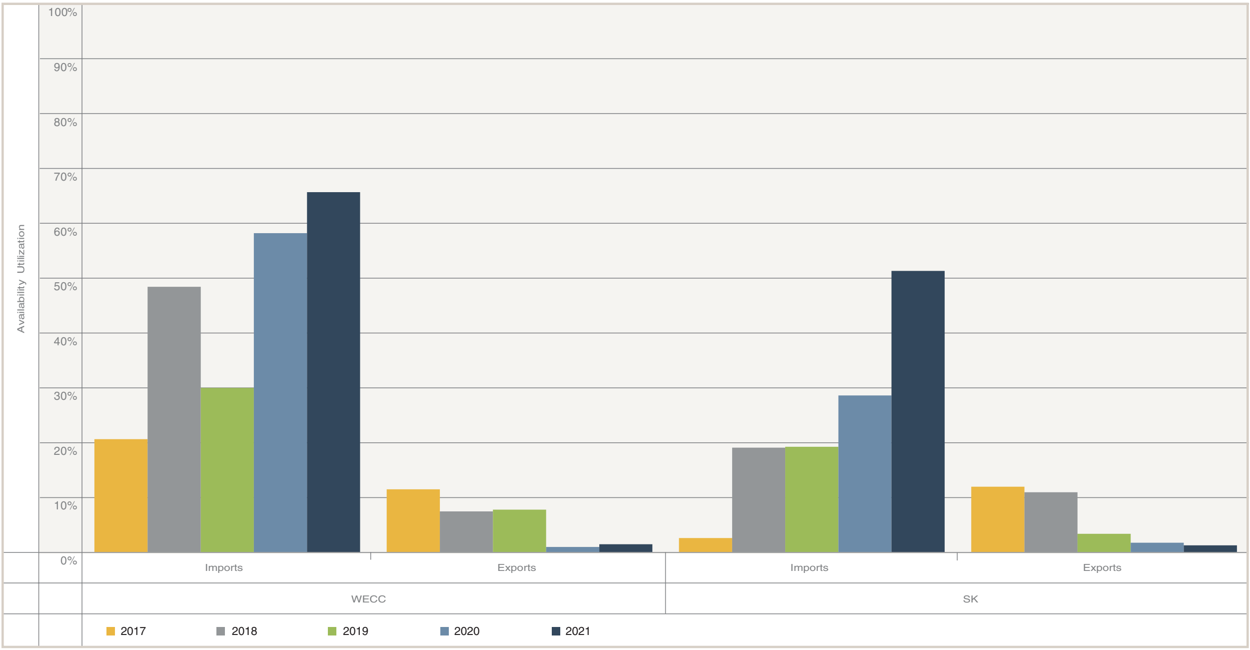


Figure 34 shows the annual interchange utilization between Alberta and the WECC regions over the past five years. In this chart, the interchange utilization represents the ratio of net imports or exports to the intertie's ATC. Imports include any volume of operating reserve procured on the intertie. The utilization calculation reflects the combined operating limit of the B.C. and Montana interties and the Alberta system operating limit. In 2021, Alberta had net imports from the WECC region in 91 per cent of the hours and was a net exporter in just under four per cent of the hours.

FIGURE 34: Annual interchange utilization with WECC region

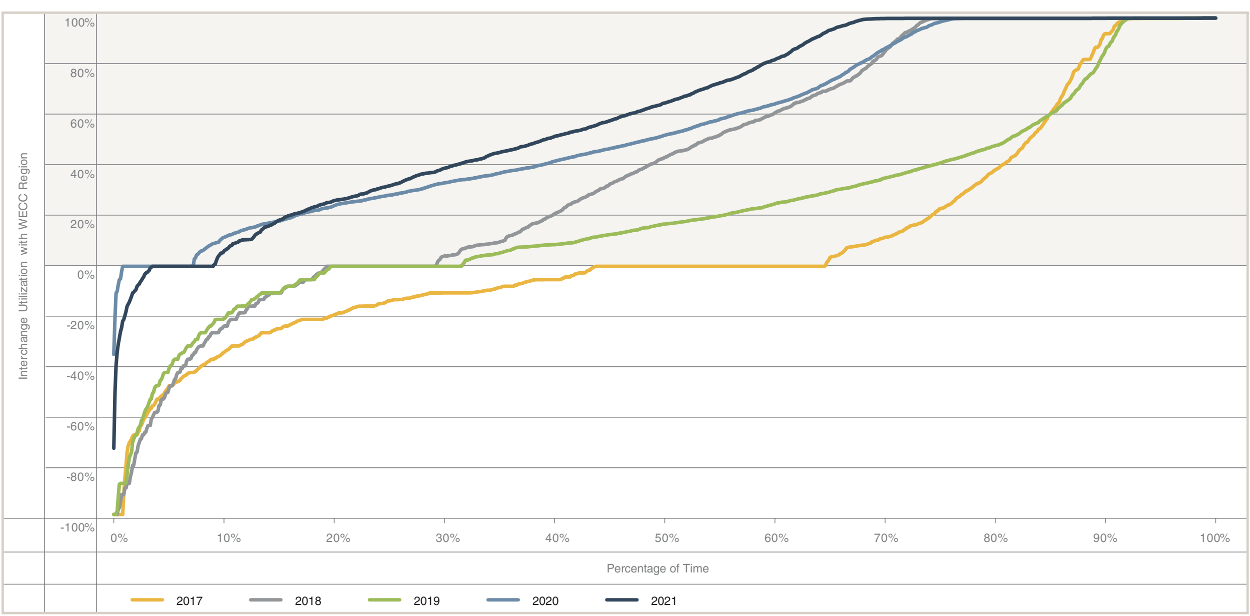
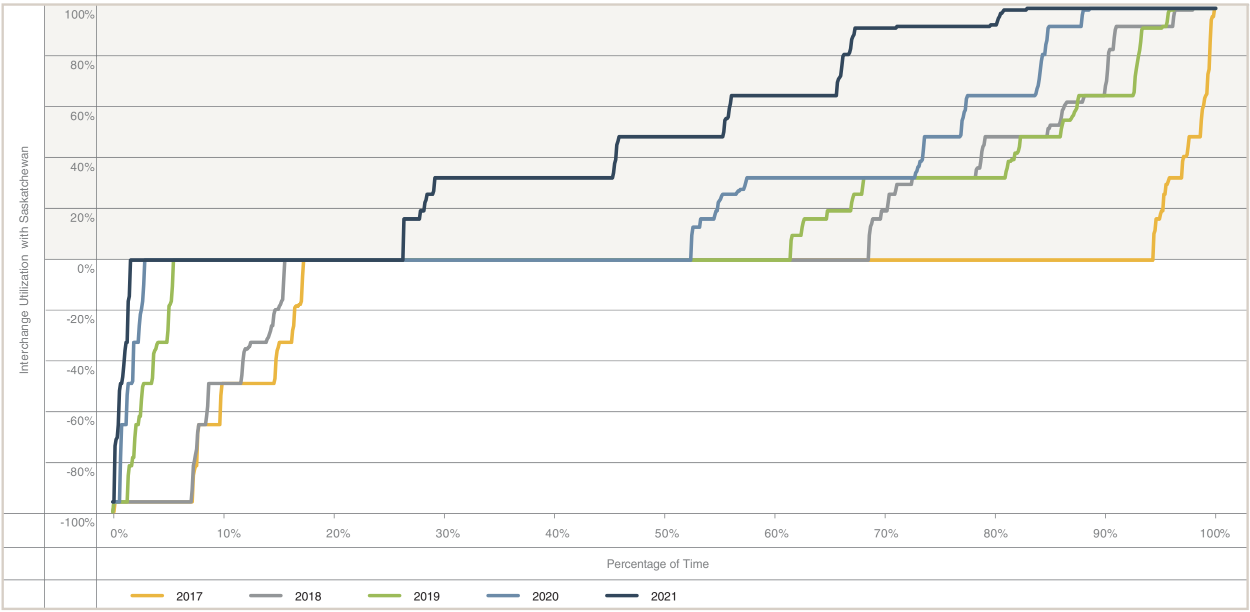


Figure 35 shows the annual interchange utilization between Alberta and Saskatchewan over the past five years. In 2021, Alberta imported energy from Saskatchewan in 74 per cent of the hours and exported energy in just under two per cent of the hours.

FIGURE 35: Annual interchange utilization with Saskatchewan



Alberta remains a net importer

Figure 36 illustrates the annual average energy transferred from each province or state. Alberta has been a net importer since 2017. In 2021, relatively higher electricity prices in Alberta led to an increase in imports from Montana and Saskatchewan. The lower imports in 2021 on the B.C. intertie, when compared to 2020, were more a reflection of higher-than-normal imports in the summer of 2020 than a reduction of imports in 2021.

FIGURE 36: Annual intertie transfers by province or state

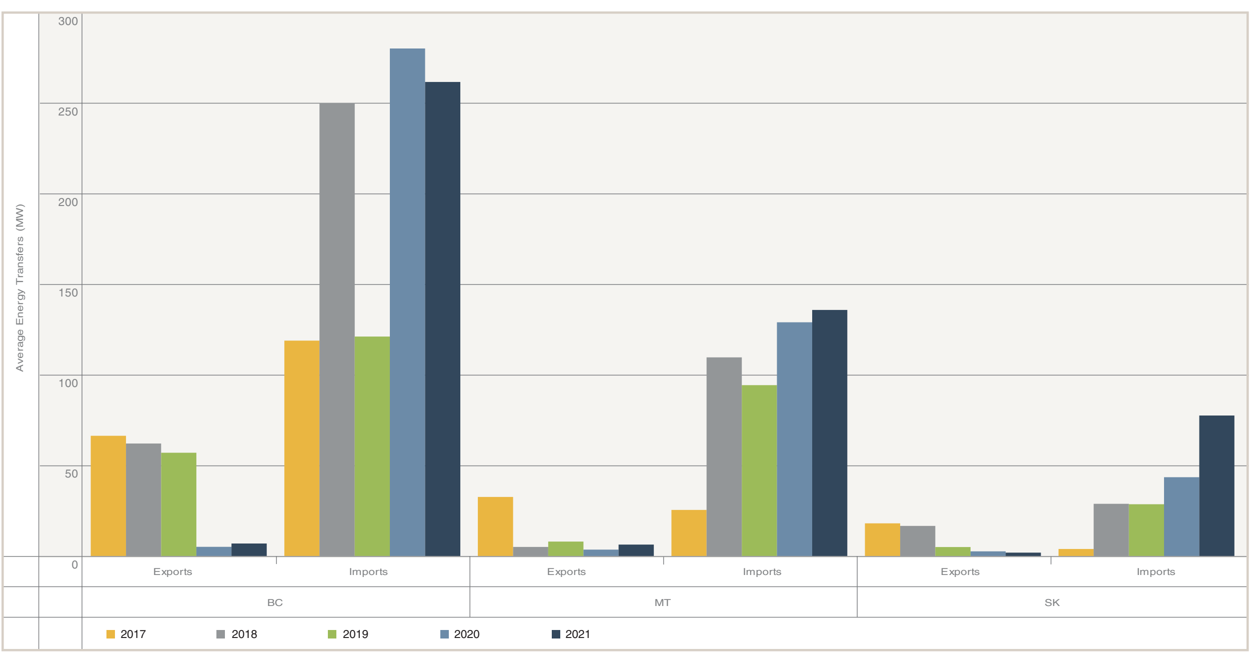
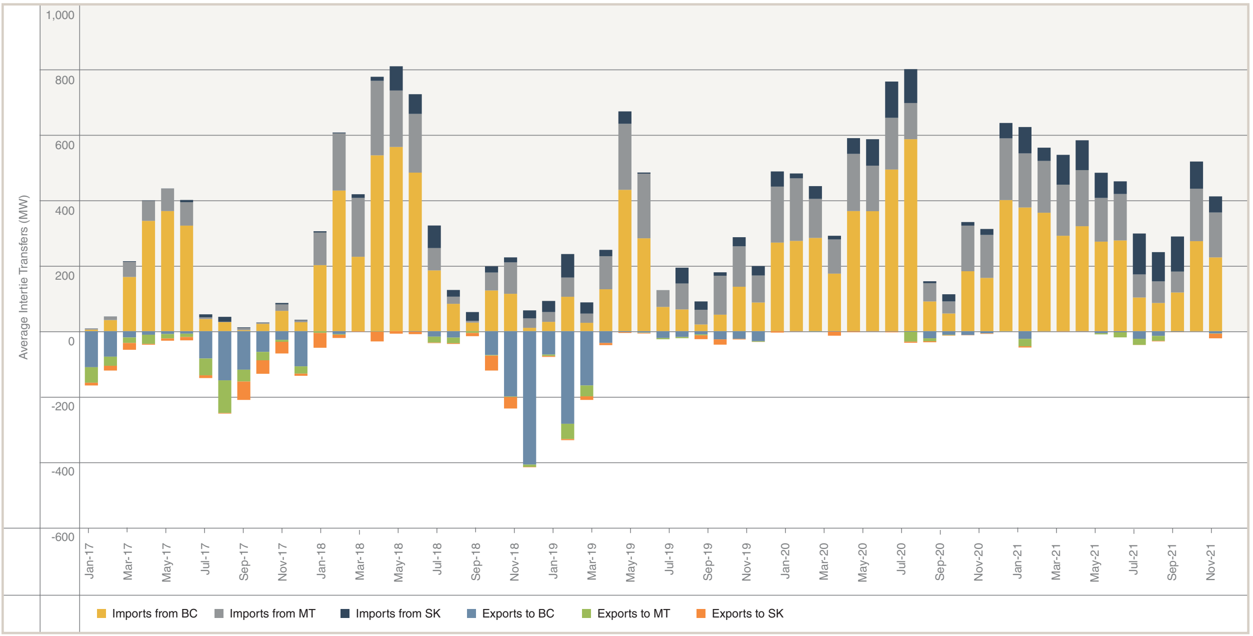


Figure 37 illustrates the monthly average energy transferred from each province or state. Positive values represent imports to the province and negative values represent exports to other jurisdictions. In 2021, imports were higher than 2020 in eight of the 12 months. Strong imports from B.C. in July and August of 2020 were the main reason for the 2021 yearly average to be lower than 2020.

FIGURE 37: Monthly average intertie transfers

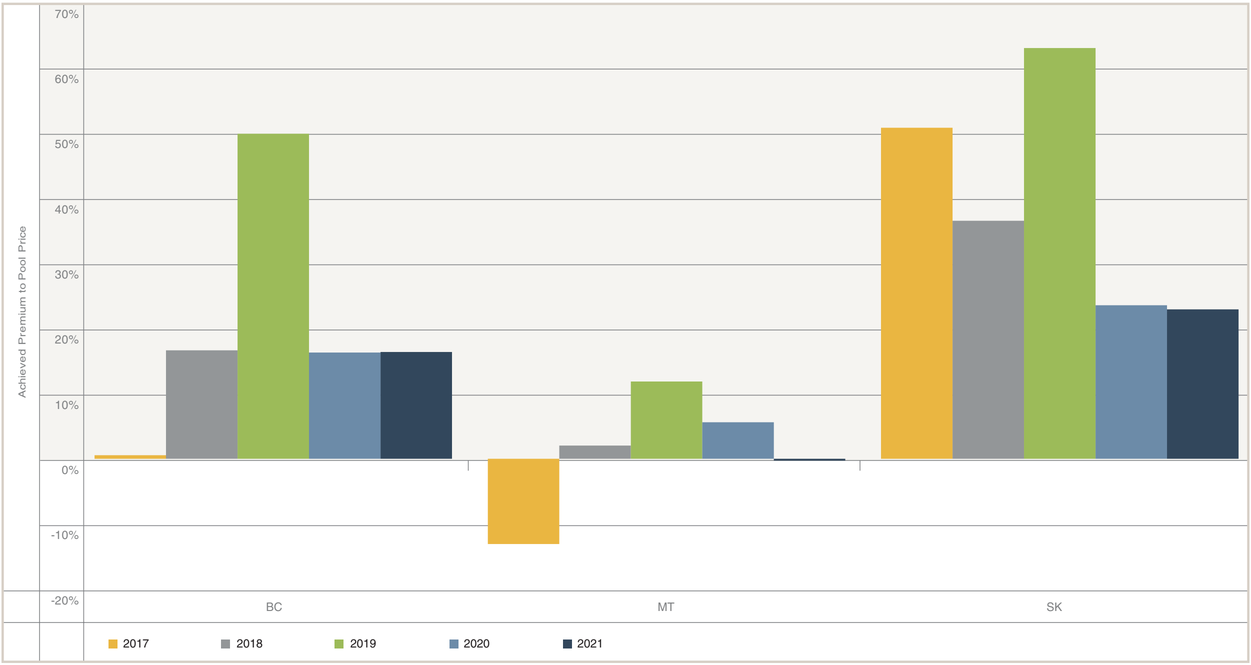


Achieved premium to pool price increased

Figure 38 illustrates the achieved premium-to-pool price on imported energy by province or state. This measure compares the average cost of imported energy versus the yearly average pool price. Imported energy exerts downward pressure on pool price. All imports are priced at $0/MWh. As a result, imported energy displaces other energy in 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 considering the price impact from the imported volume—exceeds their costs.

Year-over-year, imports from B.C. and Saskatchewan achieved a 17 per cent and 23 per cent premium, respectively, on par with 2020. Meanwhile, imports from Montana got paid virtually the same amount as the yearly average pool price.

FIGURE 38: Annual achieved premium-to-pool price on imported energy



Ancillary services

Cost of operating reserves increased

Operating reserves (OR) are used to manage real-time fluctuations in supply or demand on the AIES and ensure the system has adequate supply to respond to supply contingencies. OR is separated into two products: regulating reserve and contingency reserve (CR). Regulating reserve uses automatic generation control to match supply and demand in real time. CR maintains the balance of supply and demand when an unexpected system event occurs. CR is further divided into two products: spinning reserve and supplemental reserve. Spinning reserve must be synchronized to the grid while supplemental reserve does not. Alberta reliability standards require that spinning reserve provides at least half of the total contingency reserve.

Operating reserves are procured by the AESO on a day-ahead basis. For each of the three products of OR, the AESO procures 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 OR 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 (or zero, as there are no negative clearing prices).

The standby reserve market involves two prices: the premium and the activation price. The premium price 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 6 summarizes the total cost of OR over the past five years. The total cost of operating reserve in 2021 increased 129 per cent from 2020 to $339 million. As explained above, active OR products are directly indexed to the pool price. While not directly indexed to pool price, standby OR product prices are influenced by it. Therefore, a year-over-year 118 per cent increase in pool price was the primary driver in the increase of OR costs.

TABLE 6: Annual operating reserve statistics

Year	2017	2018	2019	2020	2021
Volume (GWh)					
Active procured	5,449	5,802	5,640	5,561	**5,624**
Standby procured	2,058	1,971	2,124	1,940	**1,191**
Standby activated	236	343	180	348	**156**
Cost ($-millions)					
Active procured	$67	$195	$172	$122	**$314**
Standby procured	$8	$8	$6	$3	**$4**
Standby activated	$6	$36	$14	$22	**$20**
Total	$81	$240	$193	$148	**$339**

Market share represents the percentage of total procured OR capacity provided by each generation technology. Figure 39 illustrates the annual market share of active OR. In 2021, hydroelectric generation had the largest market share in all three products, at 67 per cent of regulating, 45 per cent of spinning and 43 per cent of supplemental reserve. Load is close in the active supplemental reserve market, with a 42 per cent share. Figure 40 shows the annual market share in the standby OR market. Market share is more evenly distributed among the fuel types in standby, with cogeneration generation providing 36 per cent of the standby regulating and 35 per cent of the spinning reserve markets. Simple cycle has the biggest share of the standby supplemental market, with 43 per cent. In these charts, dual-fuel assets are included with coal and gas-fired-steam assets are included with the simple cycle assets.

FIGURE 39: 2021 market share of active operating reserve

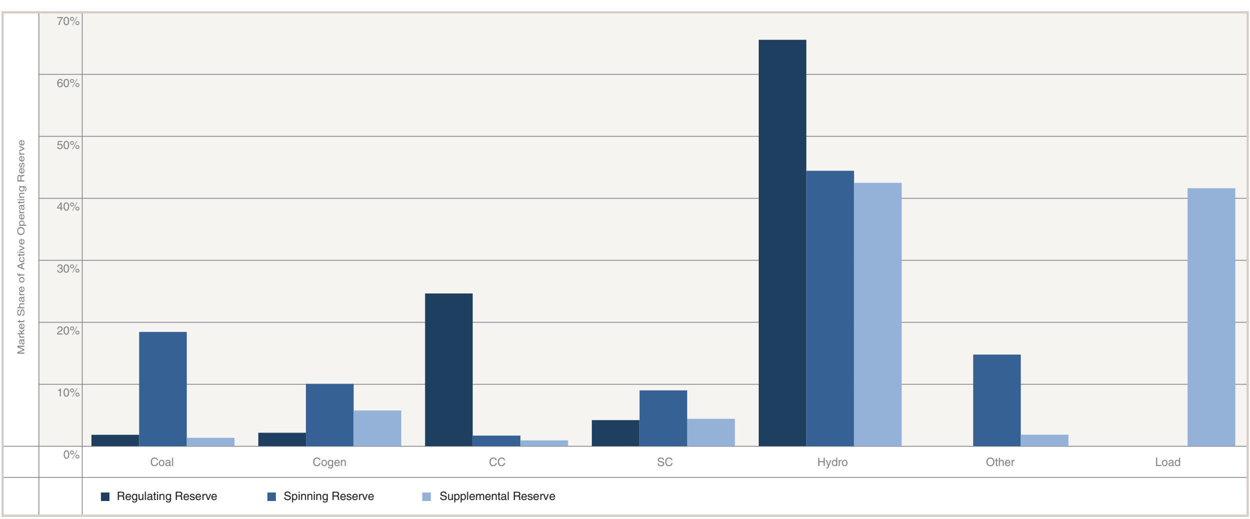
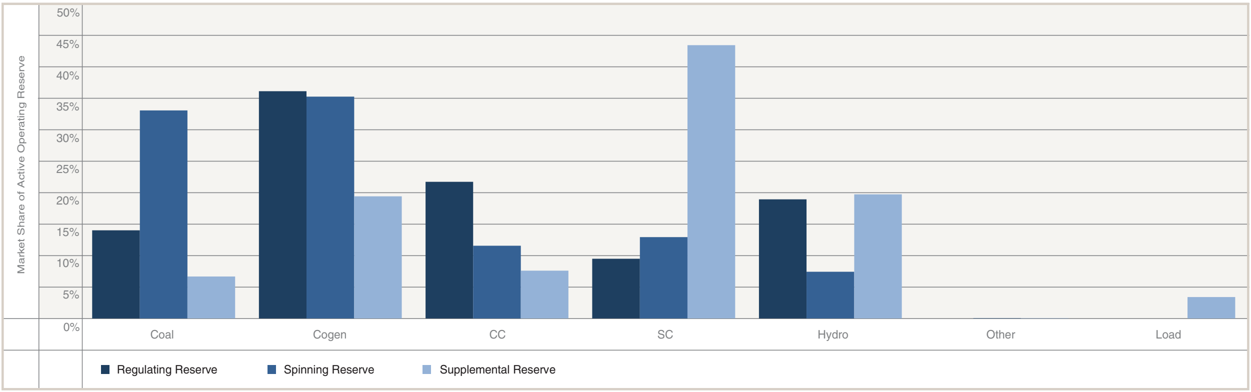


FIGURE 40: 2021 market share of standby operating reserve



Transmission must-run, transmission constraint rebalancing, and dispatch down service

The system controller issues transmission-must-run (TMR) dispatches in parts of the province's electricity system when regional transmission capacity is insufficient to provide enough imports to support local demand. A TMR dispatch directs a generator, in or near the affected area, to operate out of merit at a specified generation level 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. If unmitigated, this secondary effect interferes with the fair, efficient and openly competitive operation of the electricity market. In 2021, dispatched TMR energy was 95 GWh and costs were $5.69 million. The dispatched volume was higher than 2020 due to changed generation patterns and increased constraints in the transmission system. Costs increased due to the higher dispatched volume and higher pool prices.

When the AESO dispatches the energy market merit order, replacing in-merit generation that has been curtailed due to a constraint, dispatched generators with offers higher than the unconstrained price are eligible to receive a Transmission Constraint Rebalancing (TCR) payment. The AESO 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 MW level of energy provided by that eligible offer block to determine the amount of the transmission constraint rebalancing payment. In 2021 constraints on the transmission system required system controllers to curtail 69 GWh of in-merit energy, and the TCR payments to market participants totaled approximately $2.65 million.

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 and cannot offset more energy than is dispatched under the TMR service. The total cost of DDS is allocated between energy suppliers in proportion to the volume of energy that they generated or imported. In 2021, DDS offset virtually none of the dispatched TMR volume, as there was only 11 MW dispatched. DDS is a voluntary program and, in 2021, market participants chose not to participate as much as they had in previous years.

Table 7 summarizes the annual TMR, TCR and DDS statistics over the past five years. The total annual cost of Transmission Constraint Management (TCM), is the sum of the TMR and TCR costs.[12]

TABLE 7: Annual TMR and DDS statistics

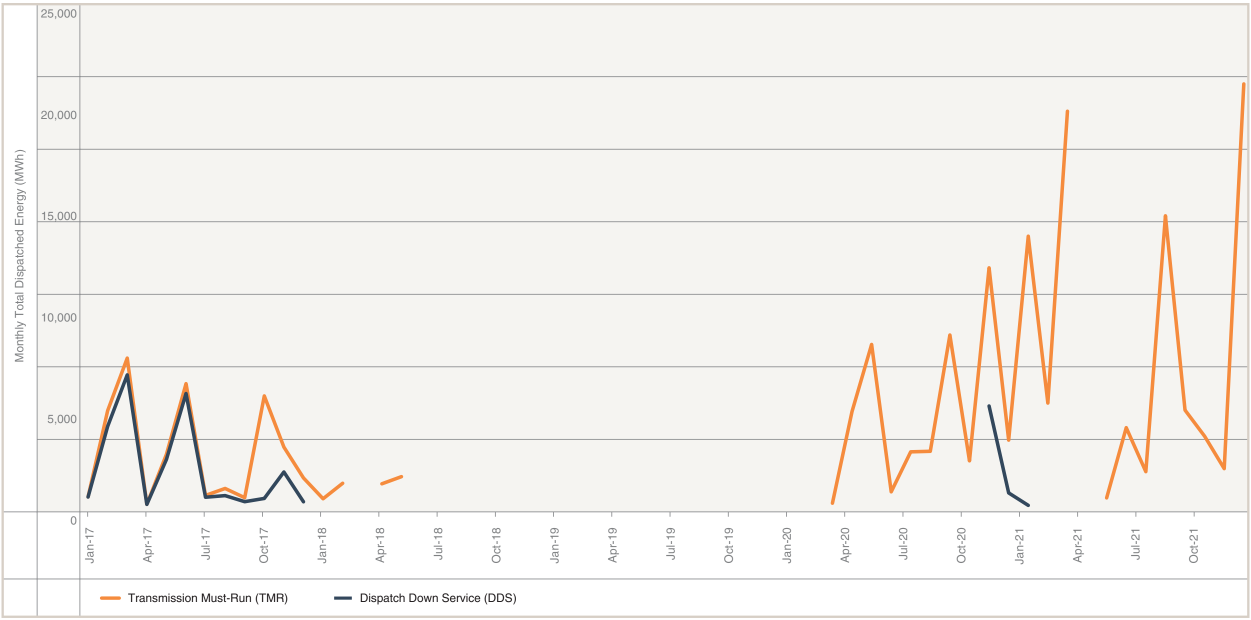
Year	2017	2018	2019	2020	2021[13]
Transmission must-run					
Dispatched energy (GWh)	35	7	5	48	**96**
Contracted TMR costs ($ millions)	$0.36	$0.01	$0.04	$0.67	**$0.01**
Conscripted TMR costs ($ millions)	$0.50	$0.43	$0.26	$0.73	**$5.69**
Transmission constraint rebalancing					
Constrained-down generation (GWh)	1	3	4	72	**69**
Number of days with TCR payment	10	7	14	67	**89**
Total TCR payments ($-millions)	$0.02	$0.04	$0.27	$0.52	**$2.65**
Total annual TCM costs					
Annual TCM cost ($ millions)	$0.88	$0.47	$0.56	$1.92	**$8.35**
Dispatch down service					
Total payments ($-millions)	$0.11	$0.00	$0.01	$0.16	**$0.00**
Dispatched energy (MWh)	23,897	106	377	8,492	**11**
Average charge ($/MWh)	$4.61	$13.21	$17.24	$18.84	**$19.58**

[12] The TCM data has been prepared pursuant to subsection 4(2) of Section 302.1 of the ISO rules, Real Time Transmission Constraint Management (Section 302.1), which requires the Alberta Electric System Operator (AESO) to: "monitor and publicly report on the costs incurred as a result of mitigating transmission constraints on an annual basis."

[13] 2021 data is preliminary.

Figure 41 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 41: 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 realized pool price for the hour. Table 8 summarizes the cost of uplift payments over the past five years.

TABLE 8: Annual uplift payments

Year	2017	2018	2019	2020	2021
Payments to suppliers on the margin					
Average range ($/MWh)	$2.35	$8.18	$12.36	$5.89	**$24.99**
Total payments ($-millions)	$0.21	$1.32	$1.58	$0.75	**$2.89**

Payments to suppliers on the margin

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 for an hour, that offer block may qualify for compensation under the PSM rule.

The annual cost of PSM increased to $2.89 million in 2021 from $0.75 million in 2020. 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 324 percent to $24.99/MWh in 2021, due to the significantly higher volatility and prices over the year.

Flexibility

In the AESO's *2020 System Flexibility Report,*[14] the AESO assessed the ability of the electric system to adapt to dynamic and changing conditions, including continuously balancing supply and demand under different scenarios. As more variable generation is integrated into the electric system, additional balancing capability may be required to respond to the combined variability of demand and variable generation, which is referred to as net demand variability. Although the flexibility assessment did not identify any emerging needs for immediate system flexibility enhancements, the results support continued monitoring and periodic assessments of system flexibility to proactively identify when system flexibility may need to be enhanced. The AESO is also currently preparing an update to its forward-looking assessment of flexibility needs for Alberta, which is expected to be released in mid-2022.

Historical flexibility parameters for market and system operations are included in the Annual Market Statistics report. In this section, these parameters are reported for the past year.

Net demand variability

The size and frequency of net demand ramps, both up and down, on the transmission system are one of the common challenges experienced with higher variable wind and solar generation. Dispatchable resources need to be able to match the size, speed, and frequency of the net demand ramps to reliably supply load customers as additional variable wind and solar generation is added to the grid.

Figure 42 provides the frequency and size of 10-minute ramps of variable generation, AIL, and net demand in 2021. The 10-minute ramp size for each parameter is the amount of change within a given 10-minute period and can be negative or positive. This was measured for every 10-minute period in the given year. Variable generation includes all five MW or larger wind and solar assets in Alberta. Small-scale wind and solar generators (i.e., less than five MW) within the province are generally connected to the distribution system and their variability is captured in AIL.

In 2021, 97.9 per cent of all 10-minute net-demand ramps were within plus/minus 100 MW, down from 98.2 per cent of ramp periods in 2020. There were 91 10-minute periods where net-demand changed more than 150 MW in 2021, up from 71 such events in 2020. Figure 43 shows the year-over-year change in the frequency in ramps of different sizes. As can be seen, the number of ramps plus/minus 30 MW decreased, while there was a corresponding increase of ramps greater than 30 MW. When more variable wind and solar generation is added to the grid, the frequency of larger net demand ramps is expected continue to increase. For context, the reduction in ramps of 30 MW or less was about 1.6 per cent of all 10-minute ramps in 2021. The distribution of variable generation ramps changed more than AIL ramps. However, some of ramps offset each other, so the change in the distribution of net demand ramp was less than the other ramps.

[14] https://www.aeso.ca/assets/Uploads/AESO-2020-System-Flexibility-Assessment-FINAL-jul-17.pdf

FIGURE 42: Distribution of 10-minute ramps for wind and solar generation, load, and net demand in 2021

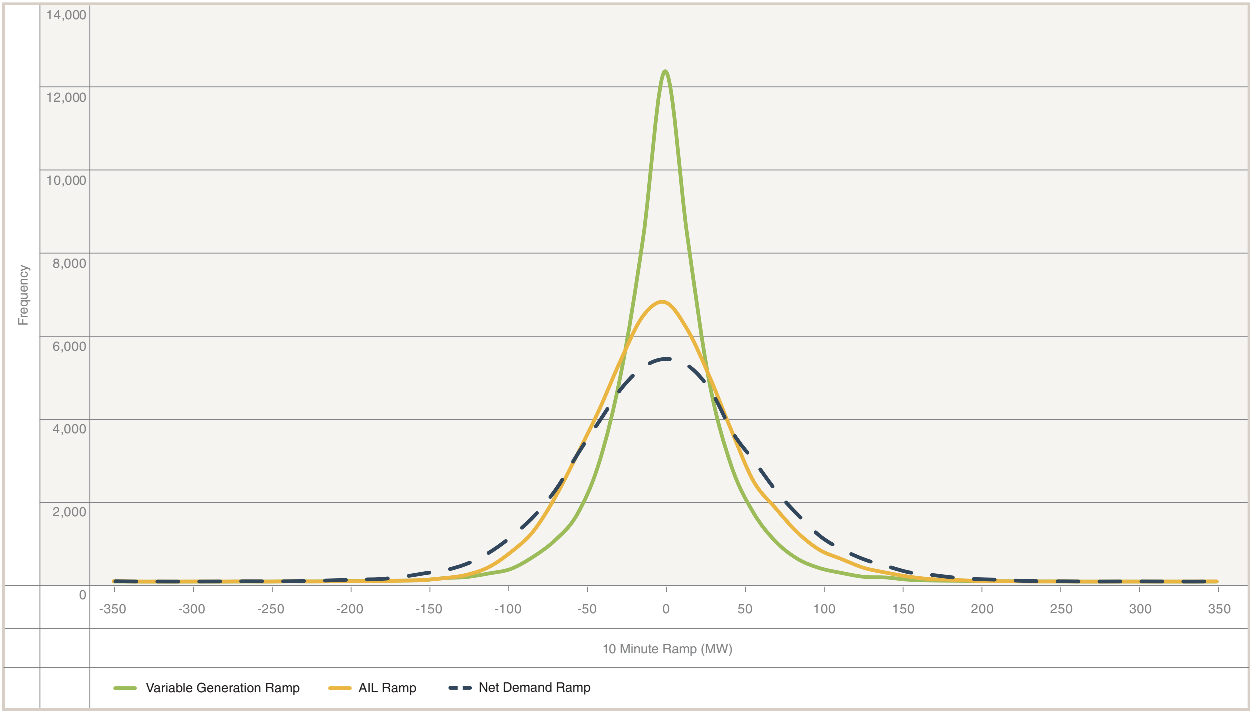
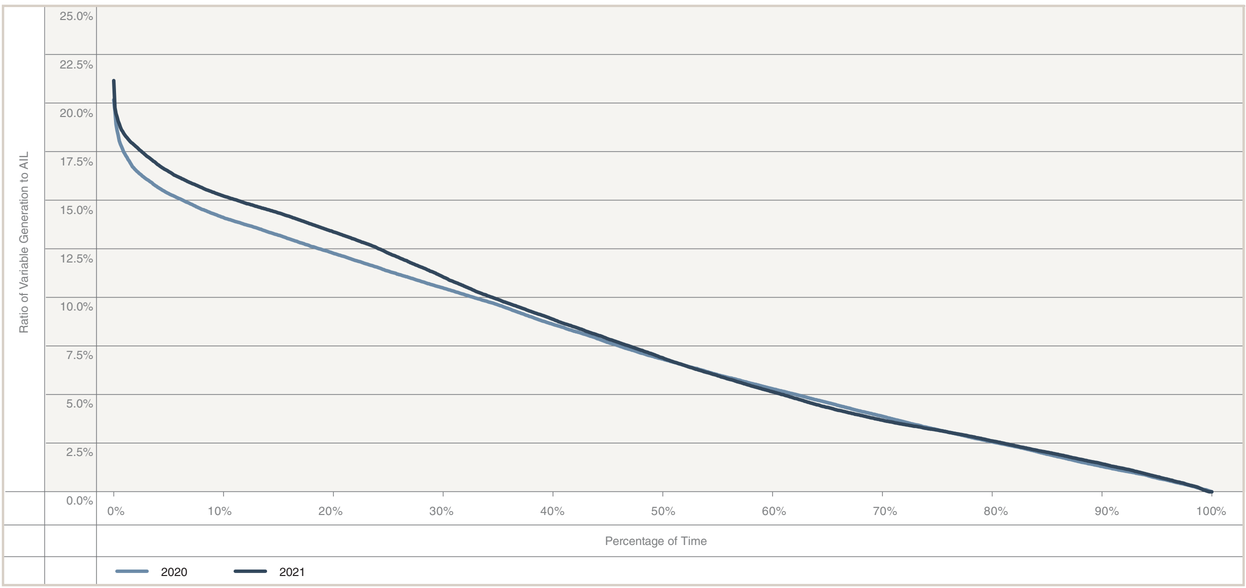


FIGURE 43: Distribution of year-over-year change in 10-minute ramps for wind and solar generation, load, and net demand

Variable generation to AIL ratio

As more variable wind and solar generation gets connected to the transmission system, it contributes a higher proportion of the overall generation production. This, in turn, is expected to create a need for greater system flexibility to respond to higher net demand variability. Figure 44 shows a duration curve of the ratio of variable generation to AIL, using the same 10-minute intervals as used in the net demand variability data. With the increased wind and solar capacity in 2021, the highest ratio of variable generation to AIL was 21.2 per cent, compared to 20.2 per cent in 2020. The 90th percentile 10-minute periods had a ratio of 15.2 per cent in 2021 versus 14.1 per cent in 2020.

FIGURE 44: Ratio of variable generation to AIL



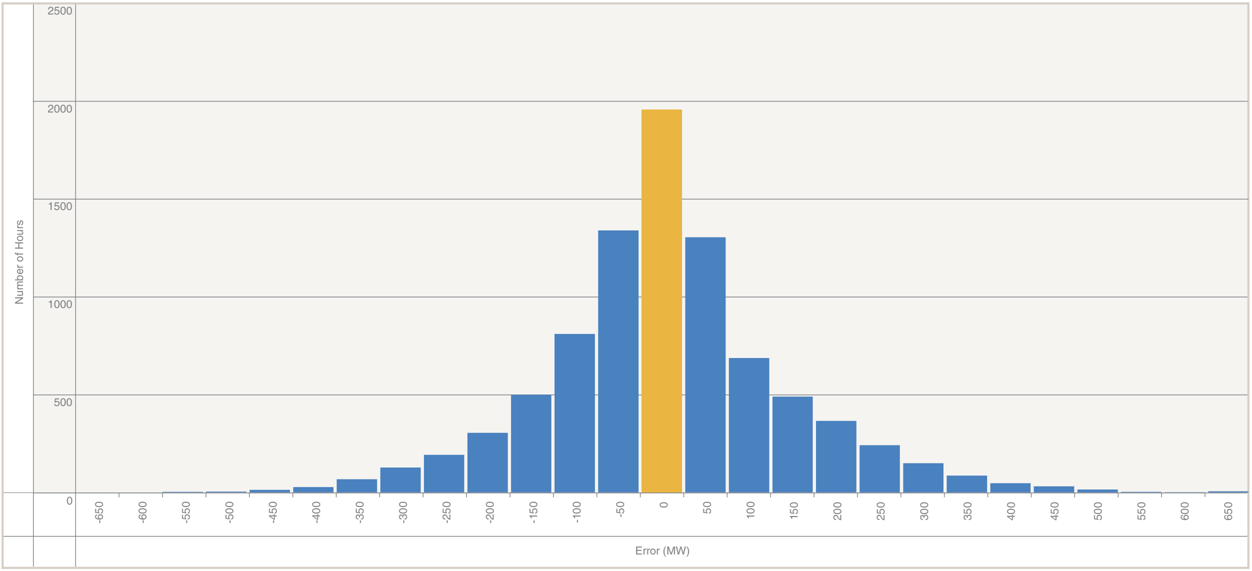
Forecast uncertainty

In Alberta, real-time energy market dispatch is performed by the system controller through the manual process of dispatching energy in the merit order. Continuous real-time system controller dispatch decisions maintain the balance between changing supply and changing demand. Every minute, system controllers face uncertainty as to what the next minute, 10 minutes, 20 minutes, etc., of net demand will be and how to match demand with dispatchable resources. The accuracy of available forecasts is not perfect; therefore, issues can arise because of uncertainty or forecast error. Accurate forecasting is important to ensure the AESO has the best information possible to manage the variability of net demand. This includes the accuracy of short-term load forecasts, as well as variable generation forecasts.

Short-term load forecast uncertainty

Figure 45 illustrates the distribution of the day-ahead load forecast error for all hours in 2021. The error at a given hour is defined as the day-ahead forecast of AIL minus the actual AIL for that hour. In 2021, the mean absolute per cent error (MAPE) was 1.0 per cent, an improvement from the 1.2 per cent in 2020.

FIGURE 45: Distribution of day-ahead load forecast in 2021



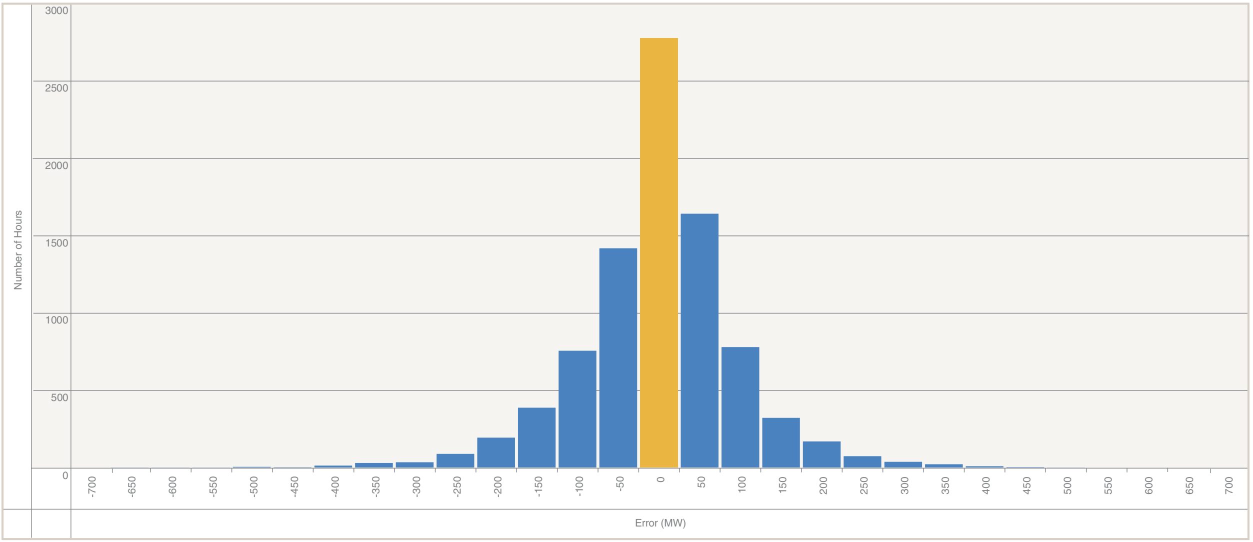
Wind power forecast uncertainty

The AESO's wind and solar power forecast uses near real-time meteorological data to predict the amount of wind and solar power that will be supplied to the Alberta system on a seven-day-ahead (long-term) and a 12-hour-ahead (short-term) basis.[15] The long-term forecast is updated every six hours and the short-term forecast is updated every 10 minutes. For the purposes of this report, the error of the short-term forecast is used to measure the uncertainty of the wind and solar forecasts because AESO system operators require accurate short-term wind power forecasts to manage net demand variability.

For a given hour, the wind power forecast error is calculated as the hour-ahead forecasted wind volume minus the actual wind generation. Figure 46 shows the distribution of the calculated errors for the wind power forecast in 2021. Overall, the average forecast error increased to 68 MW from 66 MW in 2020. However, as a percentage of installed wind capacity, the error improved to 3.5 per cent from 3.7 per cent in 2020.

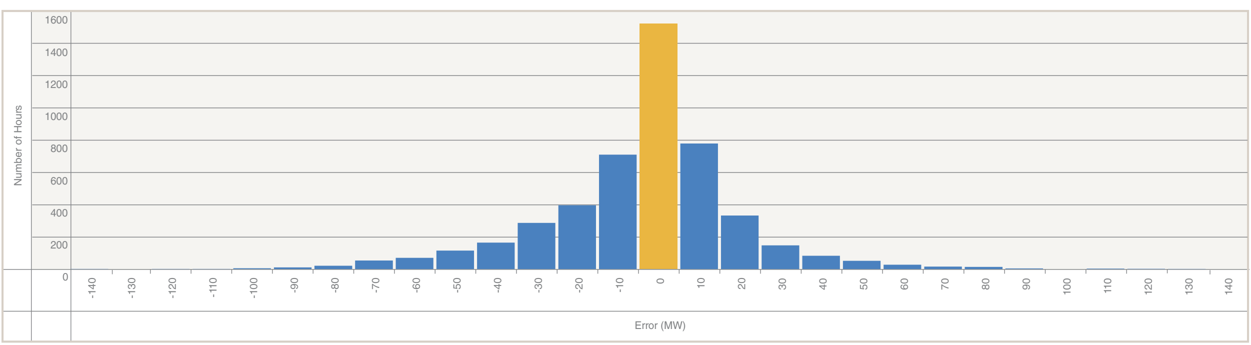
[15] https://www.aeso.ca/grid/forecasting/wind-and-solar-power-forecasting/

FIGURE 46: Distribution of hour-ahead wind power forecast error in 2021



Like the wind power forecast, the forecast error for solar power is calculated as the hour-ahead forecasted volume minus the actual volume. Figure 47 shows the distribution of the calculated errors for the solar forecast in 2021. This data excludes any non-daylight hours, where the forecast and actual generation was zero. Overall, the average forecast error increased to 16 MW from 5 MW in 2020. As a percentage of installed solar power capacity, the error improved to 5.2 per cent from 7.0 per cent in 2020.

FIGURE 47: Distribution of hour-ahead solar forecast error in 2021



Unit on/off cycling

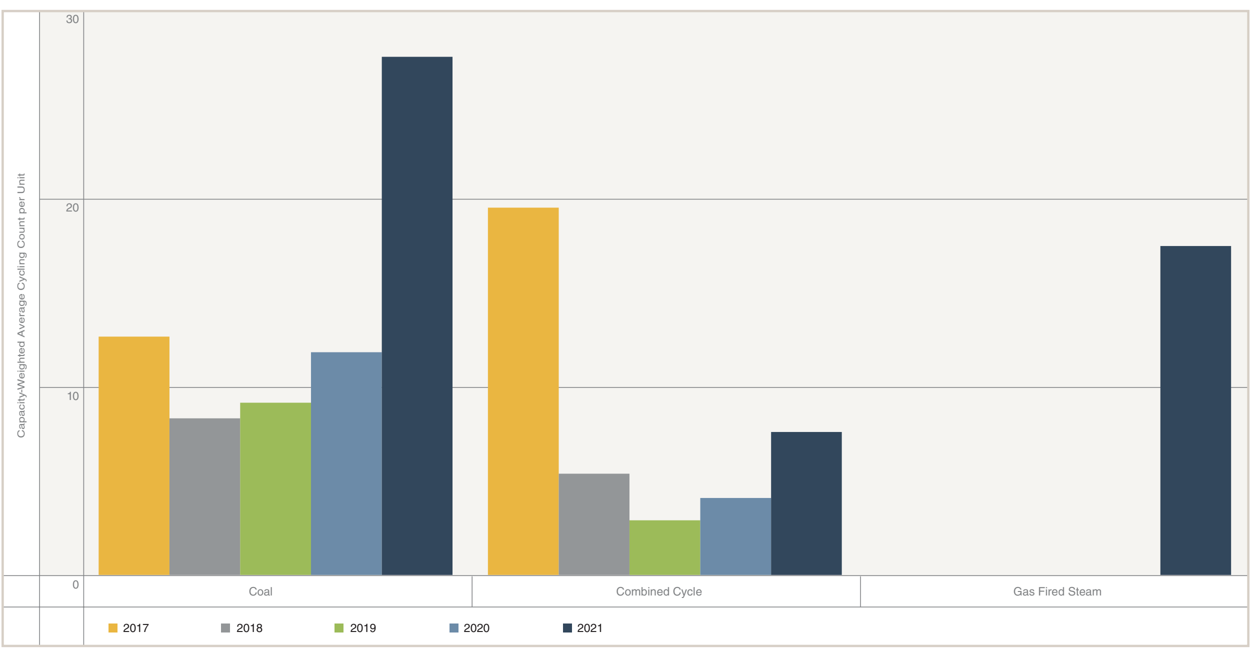
On/off cycling refers to starting up from a non-operational state, operating at any level for any duration, and then shutting down to return to a non-operational state. On/off cycling typically increases the operational costs for baseload generation such as combined-cycle and coal-fired generating units and may reduce the expected life of the generating unit. This section presents the average on/off cycles for baseload generating units weighted by maximum capability, over the past five years.

The number of on/off cycles for each unit was first counted for each year from 2017 to 2021. For each technology type and year, the average of the on/off cycles was calculated, weighted by the maximum capability of each generating unit. For units that only were available for a portion of a year, such as units that retired or converted to another fuel type, the number of on/off cycles was increased proportionately to a yearly total. All combined-cycle, gas-fired steam and coal-fired (including units capable of operating as dual fuel) units were included in the calculation, except for units within the City of Medicine Hat.

Many factors impact the number of on/off cycles experienced by an individual generating unit, including factors that affect generating unit offers (such as natural gas prices, carbon costs and other economic drivers), planned and forced outages of transmission facilities, and planned and forced outages of the generating unit itself.

Figure 48 illustrates the average number of on/off cycles over the last five years. In 2021, the increase in coal unit on/off cycling was due to increased cycling at two units, prior to their conversion to other fuel types during the year. Excluding these two units, the 2021 average was almost the same as in 2020. Similarly, the increase in cycling at combined-cycle units during 2021 was due to the significant increase at a single plant. Combined-cycle units cycled more frequently in 2017 because lower power pool prices that year meant they were on the margin more often than they were in the previous four years when the pool price was higher.

FIGURE 48: Average number of on/off cycles per generating unit, by technology and year



The AESO will continue to monitor these metrics and others as applicable, to understand the changing flexibility needs of the system as variable generation increases.

Conclusion

As the market evolves throughout 2022 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. The AESO continues to explore additional flexibility parameters and metrics which may be added to future Annual Market Statistics reports.

Much of this data is available for download via a Tableau site, accessible from the Annual Market statistics report page.[16] If there are any questions, please email market.analysis@aeso.ca.

[16] https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/

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