



AESO 2022 Annual Market Statistics

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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 2022 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.¹

In 2022, 250 participants in the Alberta wholesale electricity market transacted approximately \$19.9 billion of energy. The annual average pool price for wholesale electricity increased 59 per cent from its previous-year value to \$162.46/megawatt hour (MWh). The average natural gas price increased 49 per cent, averaging \$5.07/gigajoule (GJ). The average spark spread, based on a 7.5 GJ/MWh heat rate, increased 63 per cent to \$124.46/MWh from its previous-year value. The main reason for the rise in the average pool price was that some market participants leveraged a lower supply/demand balance and increased their offer prices. This was especially true in the latter half of the year. In addition, higher demand, low wind generation during extreme weather periods, and less imports in the last four months of the year exacerbated the impact of this offer price change.

Price	2021	2022	Year/Year Change
Pool price	\$101.93/MWh	\$162.46/MWh	+59%
Gas price	\$3.41/GJ	\$5.07/GJ	+49%
Spark spread at 7.5 GJ/MWh	\$76.39/MWh	\$124.46/MWh	+63%

Load	2021	2022	Year/Year Change
Average AIL	9,728 MW	9,883 MW	+1.6%
Winter peak	11,939 MW	12,193 MW	+2.1%
Summer peak	11,721 MW	11,381 MW	-2.9%

The average Alberta Internal Load (AIL) increased by 1.6 per cent over 2021 values due to the continued return to normal post-COVID-19, as well as an increase in industrial demand. Extreme temperatures resulted in a new winter and AIL peak of 12,193 MW being set in December 2022.

Installed generation capacity at the end of 2022 was 18,344 MW, up 6.5 per cent from 2021. An increase of 1,751 MW in renewable² capacity was partially offset by the retirement of two coal fuel units totalling 801 MW. Another two coal units converted from using coal as their primary fuel source, leaving only two dedicated coal assets. Gas-fired generation provided 72.5 per cent of total generation, while coal generation provided another 12.4 per cent. For the first time, renewable generation, at 12.6 per cent of total generation, provided more electricity than coal.

Other notable Alberta market and grid insights from 2022 include: the total cost of operating reserves (OR) increased to \$501 million, primarily due to the higher pool price; and net demand variability increased as a result of more wind and solar generation being added to the grid over the year.

¹ The link to the datafile can be found here: <https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/>

² For the purposes of this report, renewable generation refers to solar, wind, and hydro generation from units greater than 5 MW.

Price of electricity

Pool price increased 59 per cent

The pool price averaged \$162.46/MWh for 2022—an increase of 59 per cent from 2021. 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. daily; the remaining hours of the day make up the off-peak period. In 2022, the average pool price during the on-peak period increased 57 per cent to \$192.13/MWh, and the off-peak average pool price increased 70 per cent to \$103.14/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 2022, the spark spread increased 63 per cent from a year earlier.

The average pool price in 2022 was the highest ever, in nominal terms. In real terms, 2022 had the highest average pool price since 2000. There are a number of reasons for this, such as higher demand (including a new all-time record demand in December), lower supply/demand balance, higher natural gas prices, untimely generation outages, lower imports, and an increased carbon tax. However, the primary reason was that some large market participants capitalized on the fundamentals and significantly increased their offer prices.

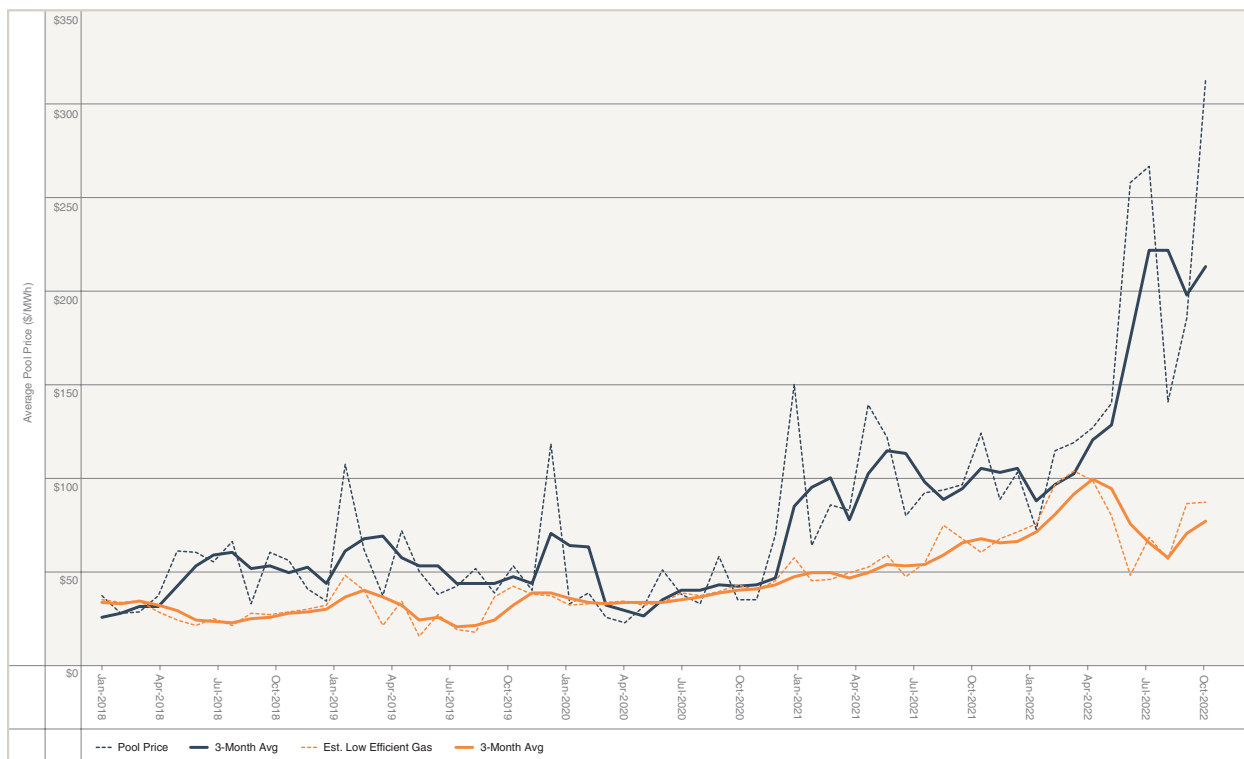
Table 1 summarizes historical price statistics over the 10-year period between 2013 and 2022.

TABLE 1: Annual market price statistics

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Pool price (\$/MWh)										
Average	80.19	49.42	33.34	18.28	22.19	50.35	54.88	46.72	101.93	162.46
On-peak average	106.13	61.48	40.73	19.73	24.46	59.28	64.12	54.72	122.61	192.13
Off-peak average	28.29	25.28	18.55	15.37	17.64	32.47	36.40	30.71	60.58	103.14
Spark spread at 7.5 (GJ/MWh)										
Average	57.58	17.56	14.12	2.77	6.70	39.54	42.21	30.81	76.39	124.46

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 2022, the monthly average pool price ranged from a high of \$311.73/MWh in December to a low of \$75.38/MWh in March. Figure 1 also includes the estimated marginal cost of a theoretical low-efficiency simple-cycle natural gas unit. This estimated cost is for a 12 GJ/MWh heat rate unit and includes \$5 for operating and maintenance costs, as well as the estimated carbon costs. For this theoretical unit, the 2022 carbon costs were \$15.16/MWh in 2022 and \$12.13/MWh in 2021. For comparison, a high-efficiency gas unit with a 7 GJ/MWh heat rate had an estimated carbon cost of \$1.13/MWh in 2022, compared to \$0.91 in 2021.

FIGURE 1: Monthly average pool price



In 2018 and 2019, the difference between pool price and the theoretical gas unit marginal cost averaged approximately \$20. In 2020, the spread between these two prices fell to approximately \$6, primarily due to a collapse in demand due to the impacts of COVID-19 restrictions. In 2021, after the return of the Power Purchase Agreement (PPA) units from the Balancing Pool to the original owners, market participants started offering power to the energy market at higher prices. As a result, the spread increased to approximately \$44. For 2022, the spread increased again, almost doubling to just over \$81. Because the estimated cost of the low-efficiency unit includes the price of natural gas and carbon costs, the increase in pool price was over and above these inputs. Fundamental conditions, such as higher demand, extreme weather conditions, reduced imports, unit outages and higher natural gas prices, would have likely increased pool prices year-over-year. However, it was the change in offer behaviour, especially from August through December, a period when gas prices were falling, that led to the record-setting pool price.³

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.

³ See section 1.4 of the MSA’s Q3 Quarterly Report for detailed analysis: <https://www.albertamsa.ca/assets/Documents/Q3-2022-Quarterly-Report.pdf>

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. From 2018 to 2020, between seven per cent (in 2020), and 13 per cent (in 2019) of hours had an average pool price of \$75 or higher. In 2021, the percentage of hours above \$75 increased to 38 per cent. In 2022, the hours above \$75 percentage almost doubled and was 67 per cent.

FIGURE 2: On-peak pool price duration curve

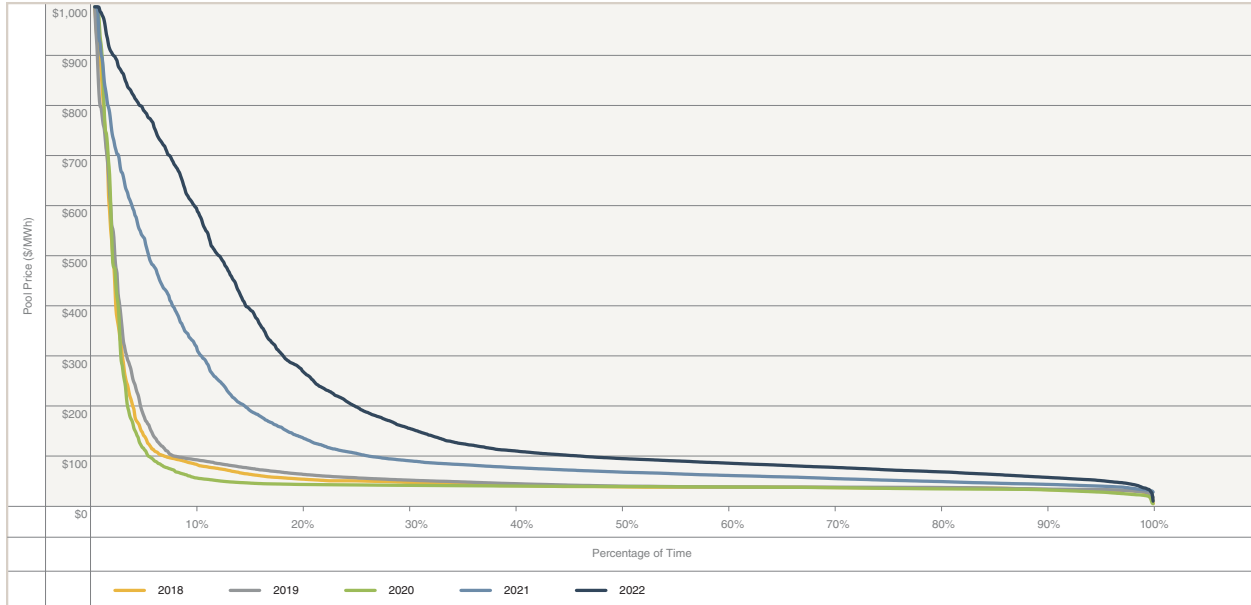
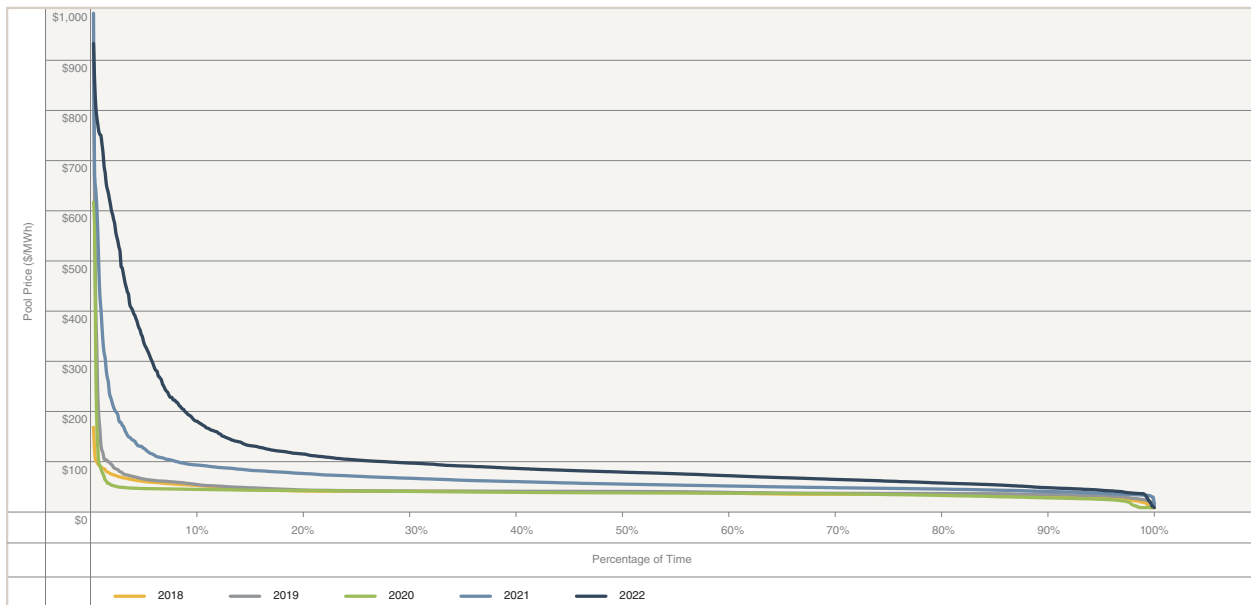


Figure 3 shows off-peak pool price duration curves for the last five years. While not as pronounced as the on-peak duration curves, a similar contrast in the duration of high prices can be seen between 2022 and the 2018-2020 period. In 2022, the percentage of off-peak hours with a price above \$75 was 45 per cent, a higher ratio than the average for on-peak hours during 2018-2020.

FIGURE 3: Off-peak pool price duration curve



Supply shortfall and surplus

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 Controller is forced to curtail firm load, the system marginal price is set to the administrative price cap of \$1,000/MWh.

In 2022, there were no supply shortfall conditions. However, there were seven Grid Alerts⁴ declared. When an Grid Alert is declared, the AESO is unable to meet minimum contingency reserve requirements and firm load interruption is imminent. During 2022, the AESO was able to manage the Grid Alerts such that no firm load was shed. The events occurred in the latter part of the year: two in September, one in November, and four in December. Each event occurred during a period of extreme seasonal demand and were accompanied by other precipitating factors including: intertie maintenance; low scheduled imports; unplanned thermal unit outages; thermal unit derates; and low renewable generation. One or more of these reasons led to each of the Grid Alert events.

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, reschedule exports, and curtail or cut in-merit generation. In 2022, there were a total six hours and 39 minutes, spread over five different days, where the market price was at \$0/MWh. However, on one of these days, the exact available volume of \$0/MWh energy was required to meet demand. During this time, no mitigation was required and no supply surplus event occurred. This compares to 2021, when slightly less than one hour of supply surplus occurred.

Spark spread increased 63 per cent

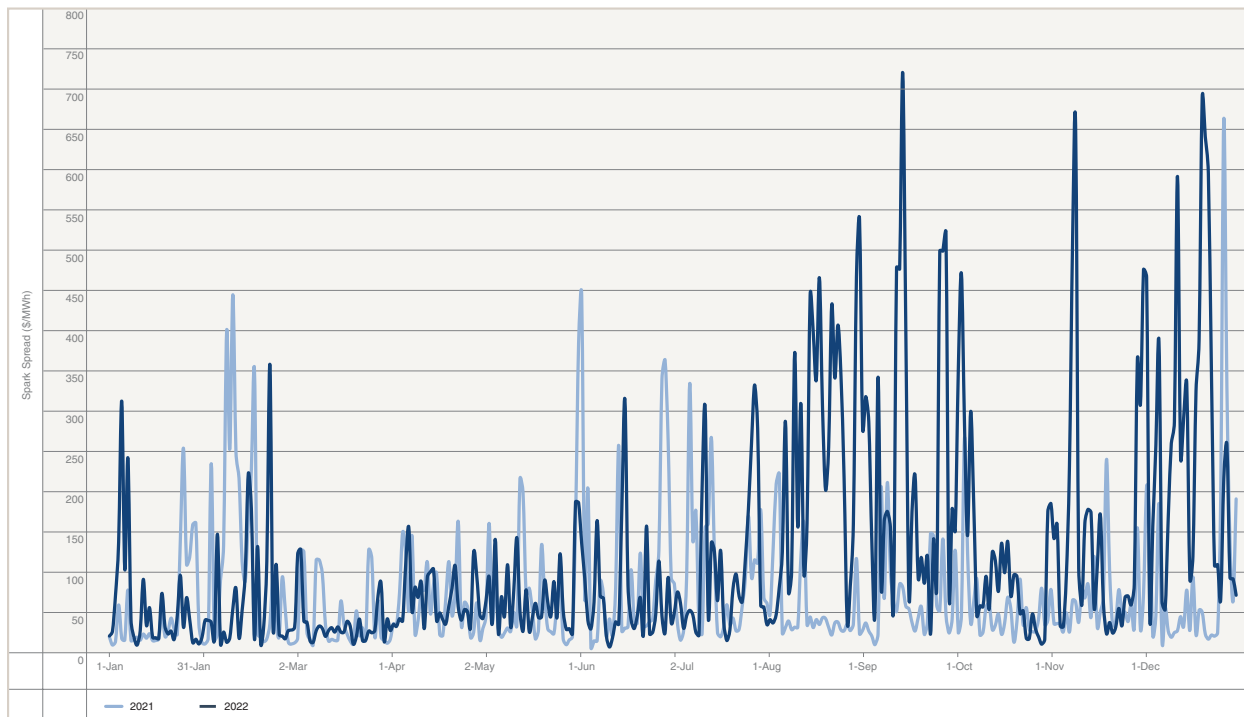
As mentioned above, the spark spread is a high-level measurement that estimates the profitability of operating a generic combined-cycle natural gas baseload generation asset in the energy market. The hourly spark spread is the difference between the wholesale price of electricity and the cost of natural 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.

⁴ Grid Alerts are level 3 Energy Emergency Alerts. For more details, see: <https://www.aeso.ca/rules-standards-and-tariff/iso-rules/section-305-1-energy-emergency-alerts/>

Figure 4 shows the daily average spark spread for 2021 and 2022. In 2022, the average spark spread increased year-over-year by \$48.07/MWh (63 per cent) to \$124.46/MWh. This is the highest nominal spark spread seen in the last 20 years.

FIGURE 4: 2021 and 2022 daily average spark spread



The reasons for higher spark spreads in 2022 are the same as for higher pool prices. The primary reason was the higher market participant offer prices into the electricity market. Other reasons included: higher demand, thermal generation outages, untimely lack of renewable generation, and reduced imports at critical times. The year-over-year change in the carbon price is estimated to have added \$3/MWh to the marginal cost of the coal-to-gas units, which were the marginal unit roughly 60 per cent of the time over the year.

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 1.6 per cent

Table 2 summarizes annual demand statistics over the past 10 years. In 2022, average AIL increased by 1.6 per cent to 9,883 MW, which was a new record. In addition, a new annual peak load record of 12,193 MW occurred on Dec. 21, 2022.

TABLE 2: Annual load statistics

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Alberta Internal Load (AIL)										
Total (GWh)	77,451	79,949	80,257	79,560	82,572	85,330	84,925	83,115	85,214	86,572
Average (MW)	8,841	9,127	9,162	9,055	9,426	9,741	9,695	9,460	9,728	9,883
Maximum (MW)	11,139	11,169	11,229	11,458	11,473	11,697	11,471	11,698	11,729	12,193
Minimum (MW)	6,991	7,162	7,203	6,595	7,600	7,819	8,024	7,579	7,976	8,110
Average change	2.8%	3.2%	0.4%	-1.1%	4.1%	3.3%	-0.5%	-2.4%	2.8%	1.6%
Load factor	79%	82%	82%	79%	82%	83%	85%	81%	83%	81%
System load										
Total (GWh)	59,375	61,530	61,299	60,775	62,383	62,919	61,599	60,172	60,961	61,853
Average (MW)	6,778	7,024	6,998	6,919	7,121	7,183	7,032	6,850	6,959	7,061
Average change	2.4%	3.6%	-0.4%	-1.1%	2.9%	0.9%	-2.1%	-2.6%	1.6%	1.5%
System Load-to-AIL Ratio	77%	77%	76%	76%	76%	74%	73%	72%	72%	71%
Implied BTF Load	2,063	2,103	2,164	2,138	2,305	2,558	2,663	2,612	2,769	2,822

AIL represents, in an hour, system load plus load served by on-site generating units, including those within an industrial system designation, as well as the City of Medicine Hat. It is consistent with the generation and load represented on the AESO's Current Supply and Demand page⁵ 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.),⁶ plus transmission losses.

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. In 2022, the load factor fell two percentage points, indicating an increased variability in load.

⁵ http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet

⁶ For system access service provided in accordance with the ISO tariff under Rates DTS, FTS, and DOS.

The system-load-to-AIL-ratio describes how much of total load in Alberta is using the bulk transmission system. In 2022, 71 per cent of Alberta’s load was using the bulk transmission system, down about one percentage point year-over-year. 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) networks is not readily available to the AESO, only the net metered load.

The implied average hourly BTF load was 2,822 MW for 2022, up 1.9 per cent from an implied 2,769 MW of BTF load in 2021. BTF load is primarily driven by industrial load, especially oil sands sites, while system load is roughly half residential plus commercial and half industrial. Therefore, a larger increase in BTF load compared to system load is indicative of AIL growth being driven primarily by industrial load. Since 2013, the percentage of AIL from BTF load has increased from 23 per cent to 29 per cent. In absolute terms, this is an increase of an average of 759 MW. In 2022, there was an increase of the hourly average BTF load of just over 50 MW.

FIGURE 5: Behind-the-Fence load as percentage of AIL

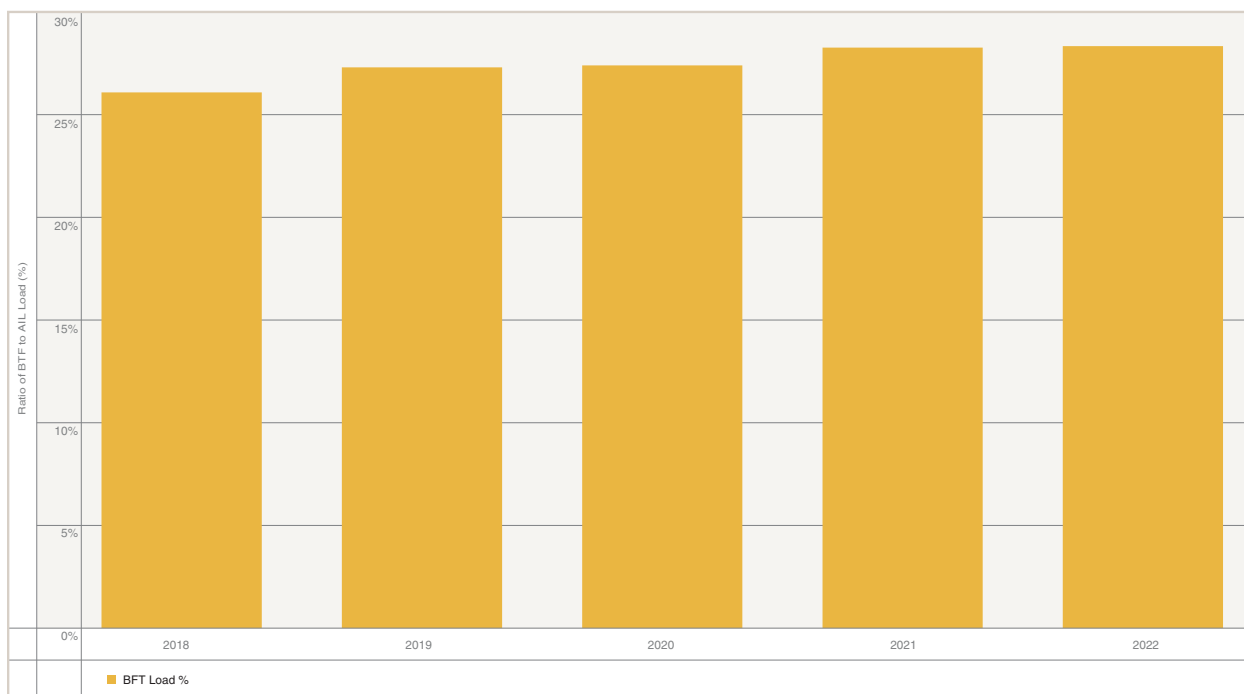
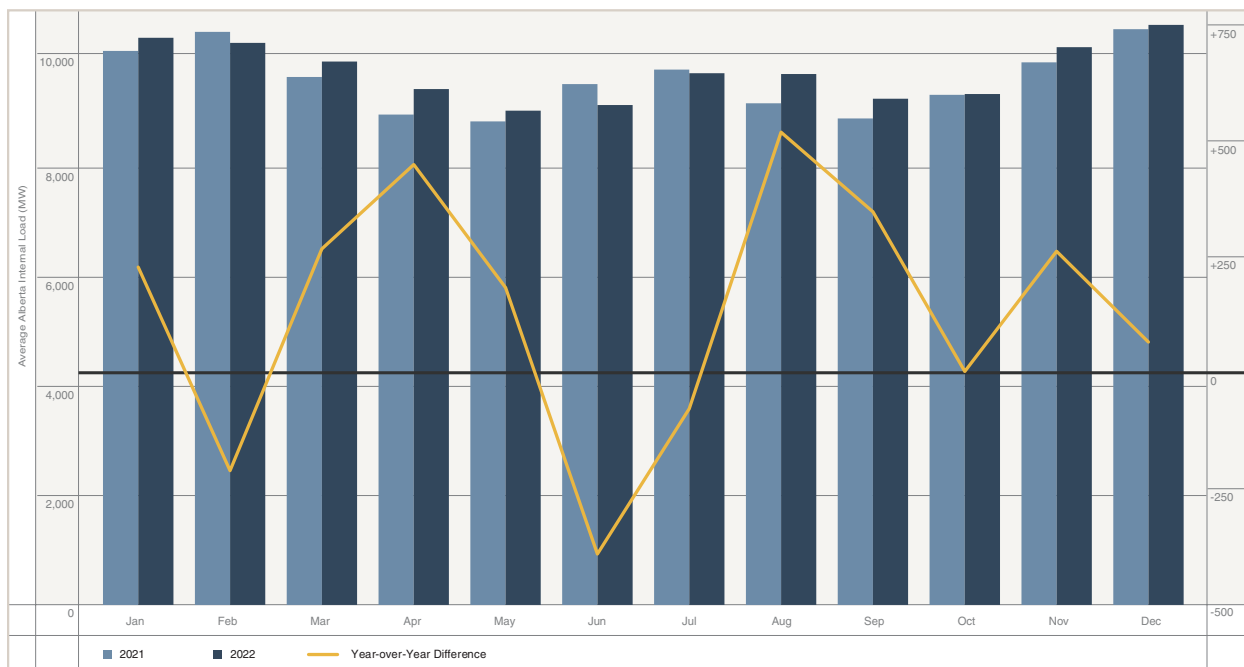


Figure 6 shows the monthly average AIL in 2022 and 2021. The year-over-year differences are primarily due to differences in temperatures between the two years. The exception is May, where despite similar temperatures, demand was higher in all regions, except the South. Overall, average demand was up 155 MW compared to 2021.

FIGURE 6: 2021 and 2022 monthly average AIL



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, all 2022 percentiles were higher than previous years, including the previous high-demand year of 2018. This implies that baseload demand, which had declined due to the fall in oil prices in 2019 and the COVID-19 pandemic in 2020, has returned to previous levels and even increased. While some of the increased load is due to the new baseload demand, some of the higher demand is a result of the extreme weather that was seen over the year. It's a similar picture in the off-peak hours, with all the 2022 percentiles higher than previous years.

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

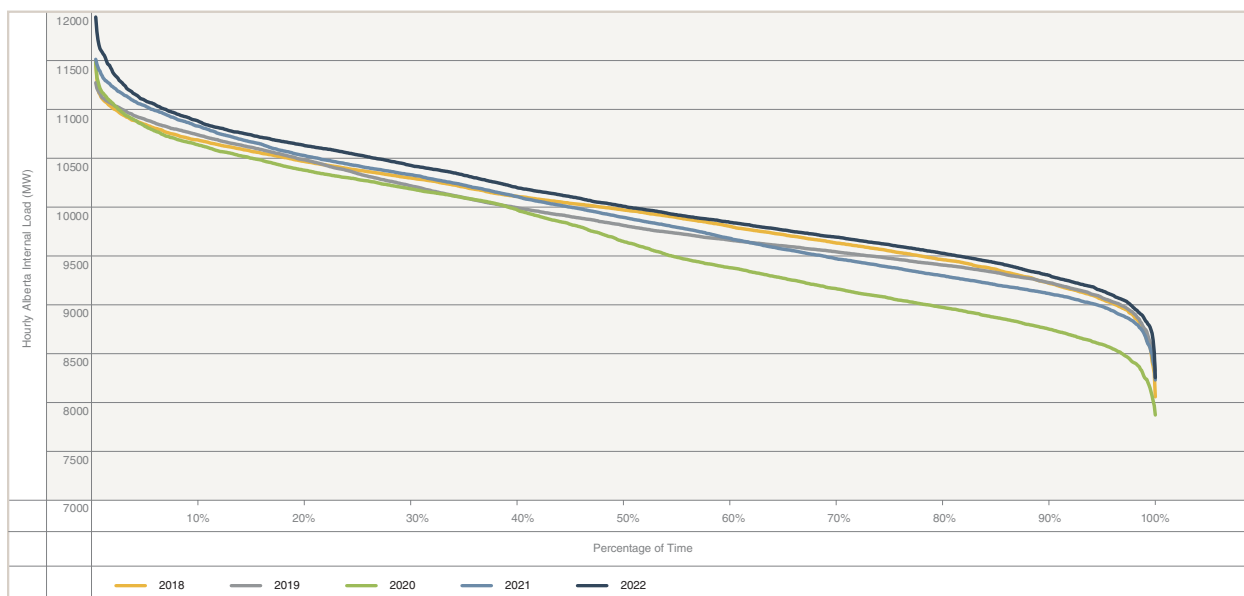
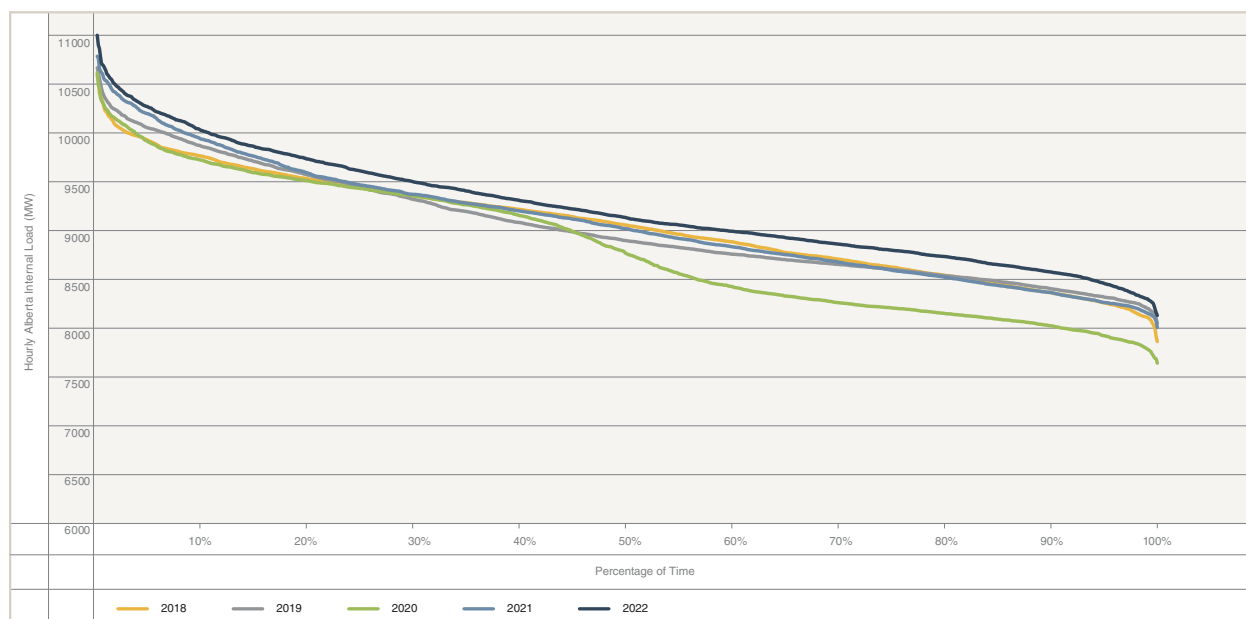


FIGURE 8: Annual AIL duration curves – off-peak hours



Seasonal load

Seasonal peaks in Alberta load are usually set during periods of extreme temperatures: summer peaks are driven by heat; winter peaks are driven by cold. Alberta has always been a winter-peaking region, meaning that the highest yearly peak occurs in the winter season. In 2022, the summer peak of 11,381 MW was set in late July. The winter peak of 12,193 MW was set in December and was a new AIL peak load record.

TABLE 3: Seasonal peak load

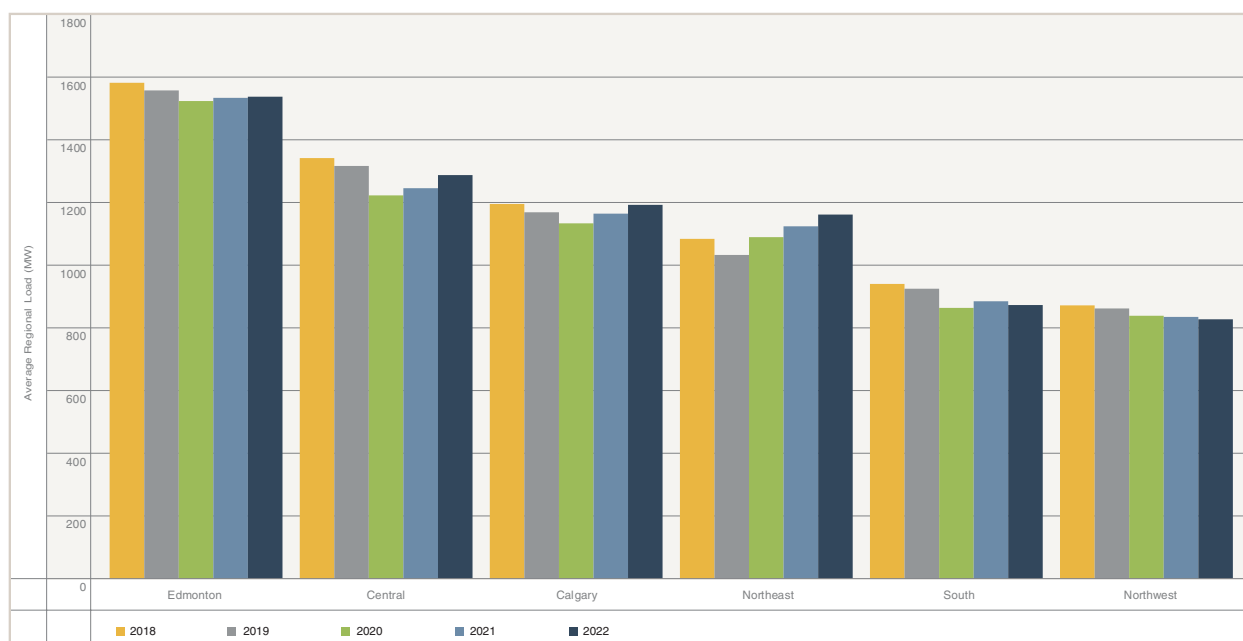
Season	Peak AIL (MW)	Date	Calendar Year
Summer 2018	11,169	2018-08-10	2018
Winter 2018	11,471	2019-02-12	2019
Summer 2019	10,822	2019-08-02	2019
Winter 2019	11,698	2020-01-14	2020
Summer 2020	10,532	2020-10-26	2020
Winter 2020	11,729	2021-02-09	2021
Summer 2021	11,721	2021-06-29	2021
Winter 2021	11,939	2022-01-03	2022
Summer 2022	11,381	2022-07-28	2022
Winter 2022 (to Feb 2023)	12,193	2022-12-21	2022

Regional system load

Figure 9 shows the average regional system load (i.e., excluding losses and BTF load) over the last five years.⁷ The Central, Northeast, and Calgary regions had the highest growth at 3.3, 3.3, and 2.4 per cent, respectively. The Edmonton region was basically the same year-over-year, while the Northwest and South saw regional load fall 0.9 and 1.4 per cent, respectively.

The growth rate in the Central region was higher primarily because BTF generation decreased. The internal growth rate was approximately 0.3 per cent. Conversely, the load growth rate in the Northwest region is lower primarily because of a growth in BTF generation. The region's internal load fell approximately 0.1 per cent. The regional load growth rate in the Northeast, Calgary, Edmonton, and South were minimally impacted by changes to BTF generation.

FIGURE 9: Regional average load



⁷ The definition of the regions can be found in the document at this link: <https://www.aeso.ca/assets/Uploads/Planning-Regions.pdf>

Generation

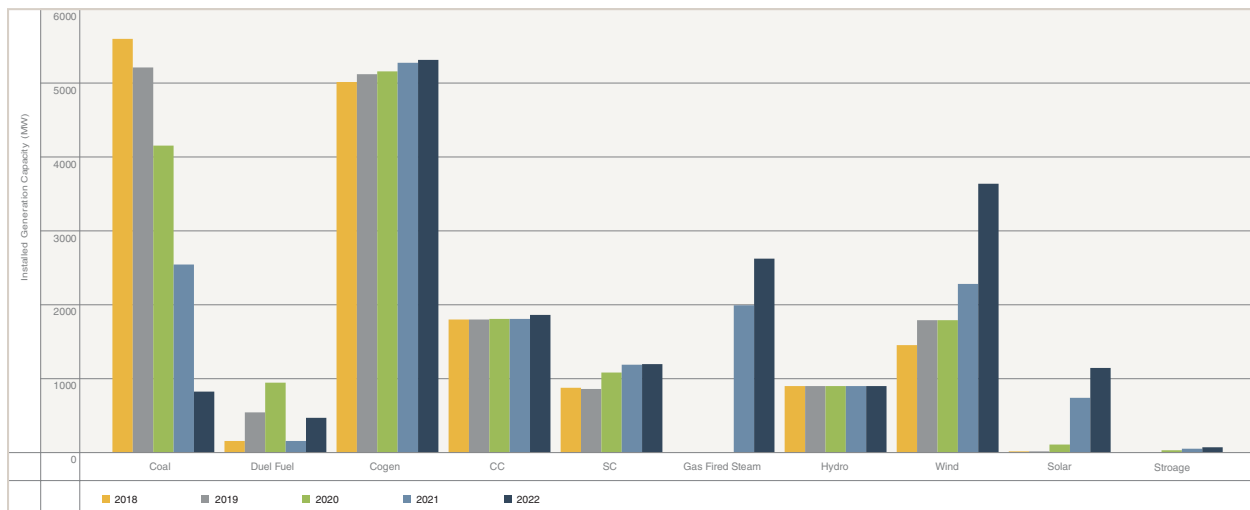
Installed generation

Year-end generation capacity increased 6.5 per cent

At the end of 2022, installed generation capacity⁸ increased to 18,344 MW from 17,224 MW at the end of 2021, an increase of 1,120 MW or 6.5 per cent. There was 1,801 MW of new generation installed, consisting of 402 MW of solar, 1,349 MW of wind, 20 MW of storage, 19 MW of gas generation and 20 MW of other generation (a dual-fuel gas/geothermal plant). Installed coal generation fell to 820 MW, down from 5,568 MW in 2018. Roughly 929 MW of 2021 coal generation converted to gas (Keephills 3) or dual-fuel (Genesee 3) during 2022. Another 801 MW of coal was retired (Keephills 1, Sundance 4). One unit, Battle River 4 (155 MW), converted from dual fuel to gas. Finally, there were numerous changes to maximum capacities, both up and down, across all fuel types of the fleet.

At year-end, purely gas-fired generation was 60 per cent of Alberta's installed generation capacity. Coal-fired generation, including dual fuel, was seven per cent, down from 36 per cent in 2018. Renewable generation was 31 per cent, up from 15 per cent in 2018. Figure 10 shows the installed capacity of each fuel type at the end of each of the last five years.

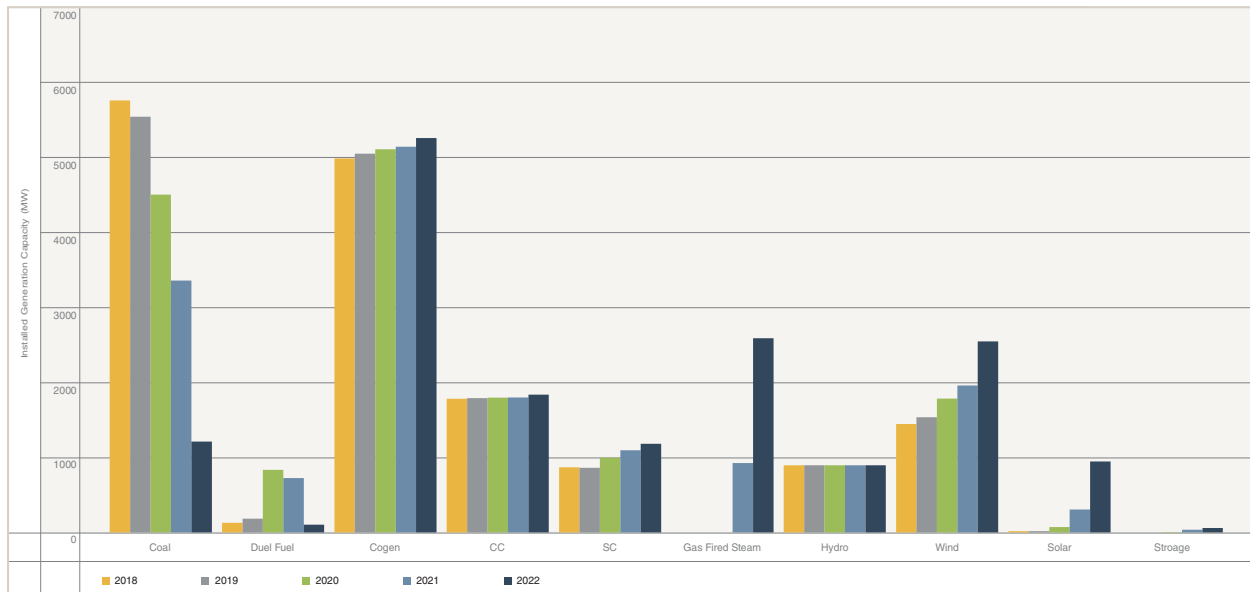
FIGURE 10: Year-end gross generation capacity by technology



The average annual installed generation capacity is the average capacity over the entire year, not just at year-end. It accounts for when the capacity changes occurred in the year. In 2022, the change in the average annual installed generation capacity, while not as significant as the year-end capacity, also showed an increase. During the year, installed capacity averaged 17,203 MW, compared to 16,699 MW in 2021, for an increase of 3.0 per cent. The main drivers for the difference between the average and year-end capacity was the retirement of the coal assets by the end of Q1, while most of the new renewable projects came online in the second half of the year. Figure 11 shows the changes in the average annual capacity of each technology type.

⁸ 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 by a significant period of time.

FIGURE 11: Average annual gross generation capacity by technology

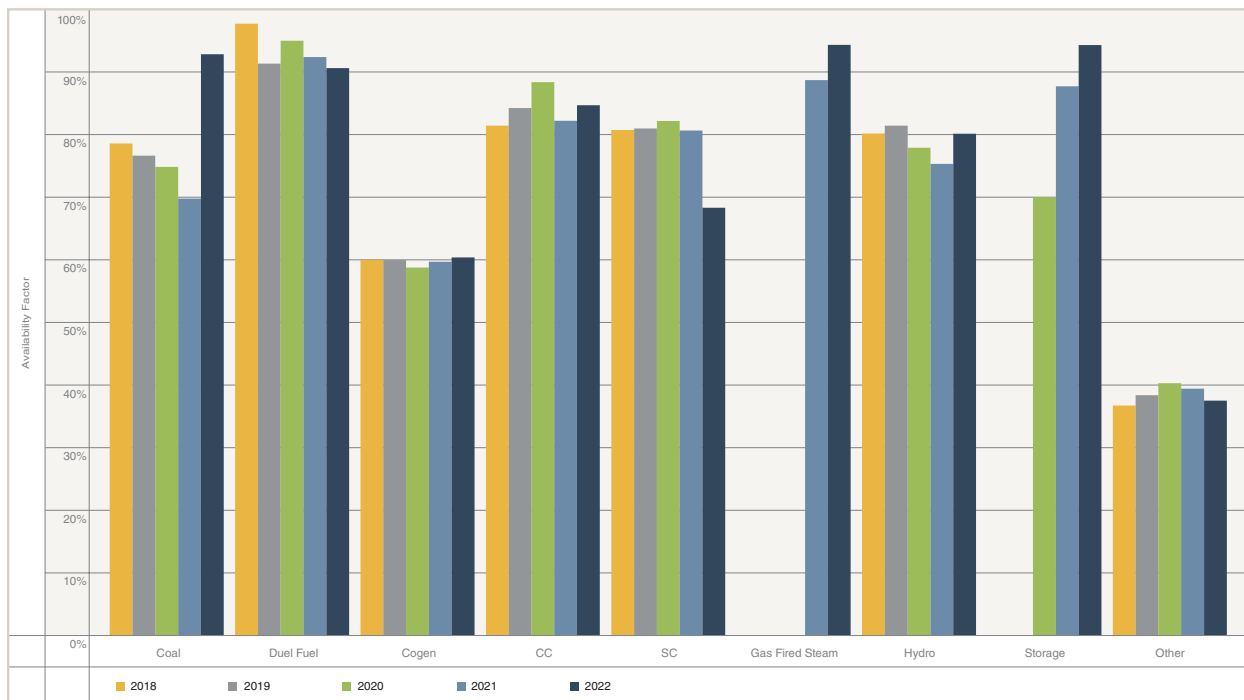


Generation availability

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 part of the calculation, but the installed capacity is included in the generation capacity volume. Because it is used mainly for BTF generation, cogeneration assets tend to have a low generation availability. Figure 12 illustrates the annual average availability factor by generation technology.

Availability of coal-fired generation increased significantly this year because of the retirement of less reliable units. In addition, with only a few assets left, there was no major maintenance outages required during the year. As a result, there was a much smaller capacity of coal units that were available more frequently. The simple-cycle technology saw reduced availability due to an unexpected long-term outage at one of the units.

FIGURE 12: Annual net-to-grid availability factor by technology



Coal technology had the highest utilization factor

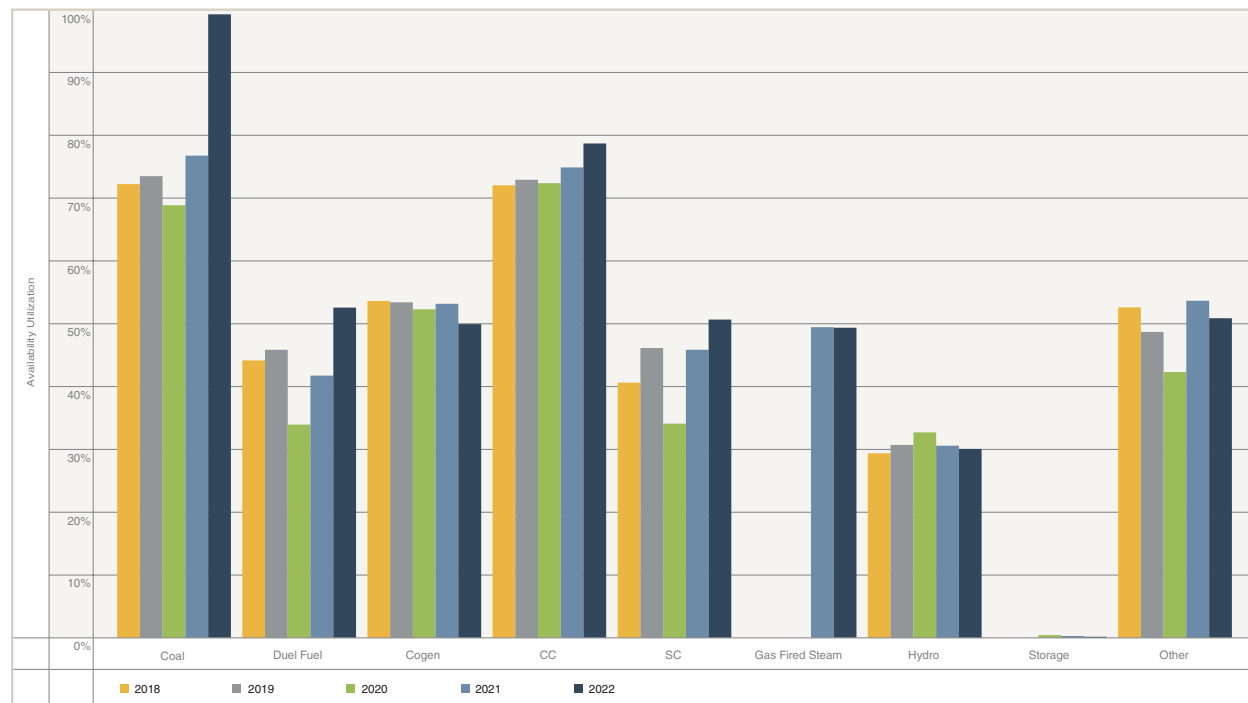
Availability utilization represents the percentage of the available power that was dispatched to serve system load. Net-to-grid generation is the generation dispatched to meet system load. Capacity and generation used to supply behind-the-fence load has been excluded from the availability utilization calculation. Availability utilization is calculated as the ratio of net-to-grid generation to net-to-grid available capacity. Wind and solar generation are also excluded from this calculation since all available wind and solar power is fully utilized, except in rare circumstances. Figure 13 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.⁹ Starting in 2018, the combination of lower gas prices and higher carbon costs led to combined-cycle gas generation replacing coal-fired generation as the lowest cost—and therefore the most utilized—generation technology. This changed starting in 2021, as higher gas prices and the retirement and/or conversion to gas of less efficient coal-fired generation, led to coal-fired generation having the highest utilization factor again. In 2022, with the retirement of two more coal units, the remaining assets were the most efficient and lowest cost. They were typically offered in the market as a price taker, which led to the coal assets having a 99 per cent utilization factor.

⁹ Dispatchable technologies refer to non-variable generation resources which can be dispatched up or down to follow load regardless of environmental conditions.

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 available to the grid. Storage has a very low utilization—not zero, but less than 0.5 percent—primarily due to the fact that these assets mainly provide ancillary services and aren't in the energy market.

FIGURE 13: Annual net-to-grid availability utilization factor by technology

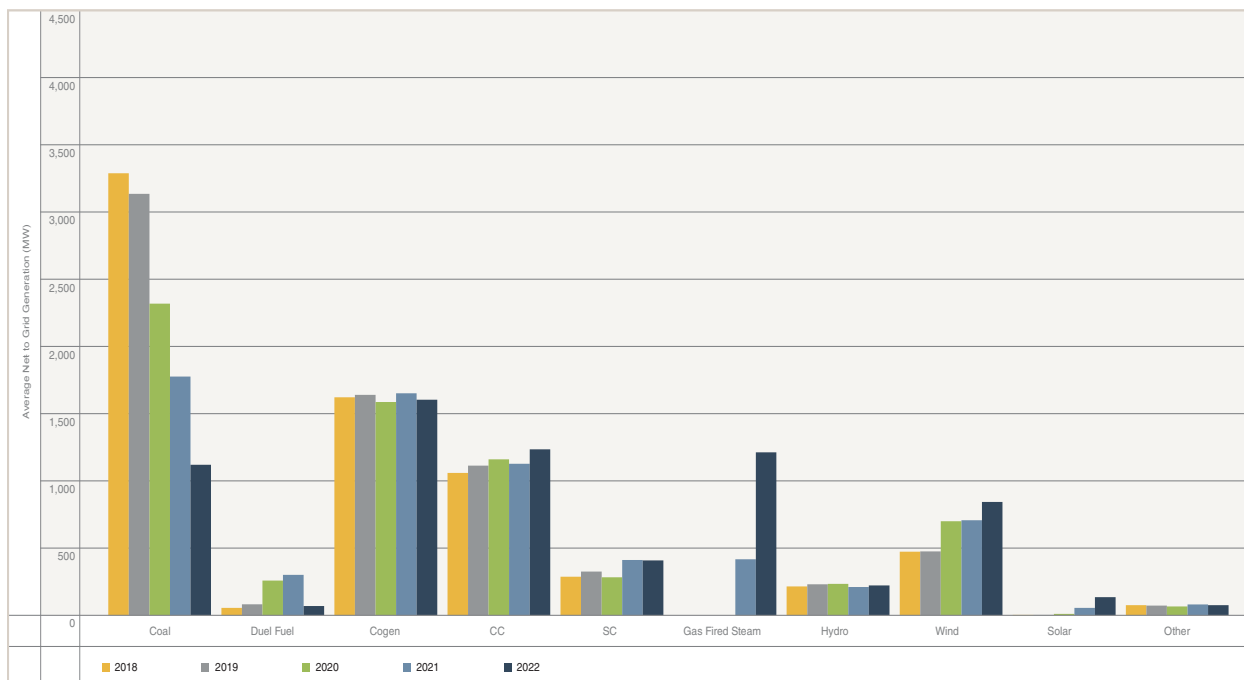


Gas generation supplied 64.4 per cent of net-to-grid electricity

Figure 14 illustrates the average hourly volume of generation from each technology that was dispatched to serve system load over the past five years. In 2022, pure gas-generation technologies delivered 64.4 per cent of net-to-grid generation in Alberta, up from 41.9 per cent in 2018. Coal generation provided 17.2 per cent, down from 47.2 per cent in 2018. Finally, renewable generation provided 17.3 per cent of Alberta's net-to-grid generation, up from 9.8 per cent in 2018. For Alberta, this is the first year that renewable generation has provided more generation than coal on an annual basis.

Of the net-to-grid generation, wind generation supplied 12.2 per cent, versus 10.5 per cent in 2021 and 6.7 per cent in 2018. Solar electricity provided 1.9 per cent, compared to 0.8 per cent in 2021 and virtually nothing in 2018. Finally, hydro provided 3.2 per cent, which is about average for the technology.

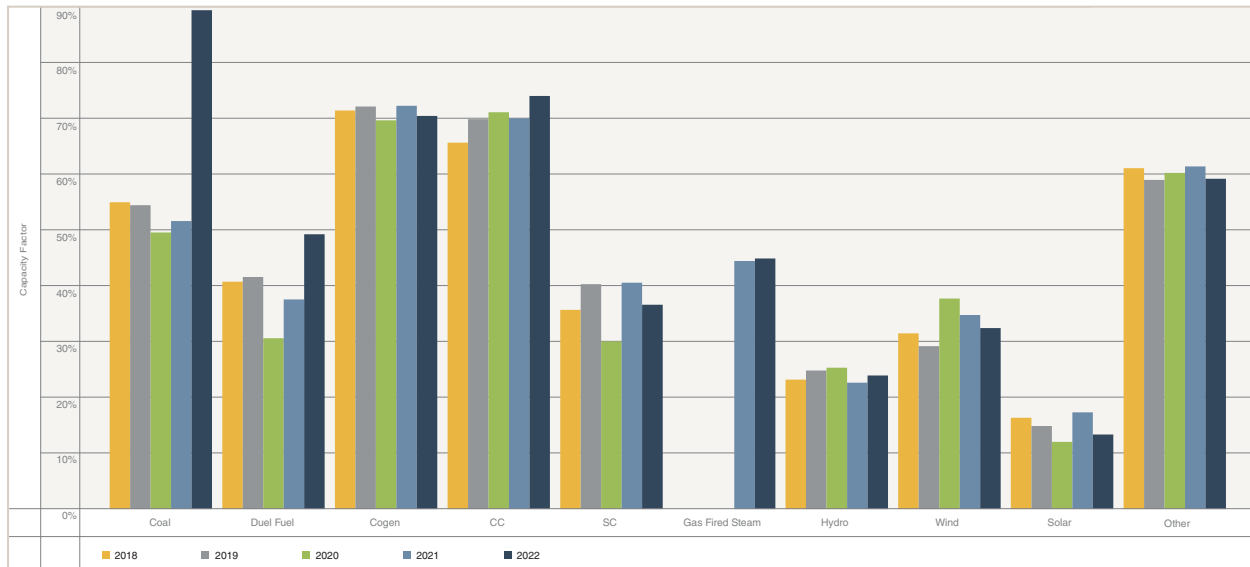
FIGURE 14: Annual average net-to-grid generation by technology



Coal assets had the highest capacity factor

Capacity factor represents the percentage of installed capacity used to generate electricity. Capacity factor is calculated as the ratio of average generation to the maximum capability over the given year. In previous years’ reports, this was calculated using only generation that was delivered to the grid (i.e., net-to-grid). This year, it is being calculated using total generation of all assets with an installed capacity of greater than 5 MW. It does not include smaller, distributed generation. While not perfect, this gives a better representation of how the entire generation fleet performed, including those assets that are used to self-supply load. The main impact of this change, as compared to previous reports, is the noticeable increase in the capacity factor of cogeneration and “other” assets. There was also a smaller increase to the capacity factor of combined-cycle and simple-cycle assets. Energy storage is excluded from this chart, as those assets do not have the ability to provide continuous generation over long periods of time. Figure 15 illustrates the annual capacity factor by generation technology.

FIGURE 15: Annual capacity factor by technology



In 2022, coal assets had a capacity factor of 92 per cent—meaning for every 100 MW of installed capacity, coal assets generated 92 MW each hour. The large increase from previous years was a combination of the retirements and conversions of other less efficient coal assets, as well as very few derates or major maintenance outages for the remaining units. Dual fuel saw an increased capacity factor due to the conversion of a less efficient asset to gas and a more efficient unit from coal.

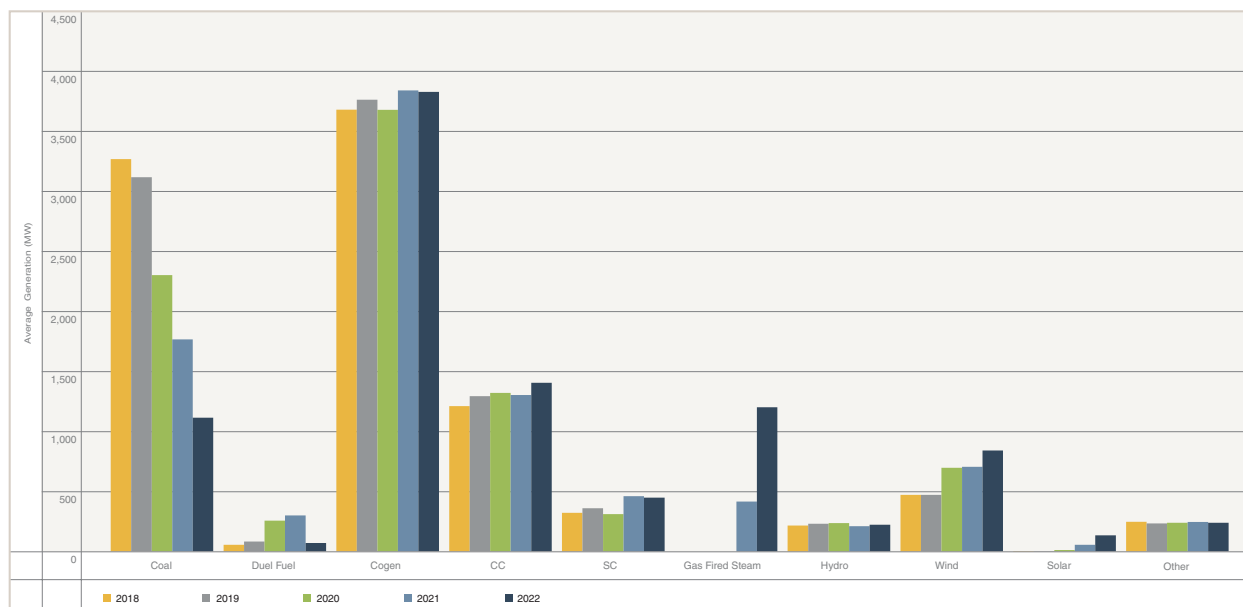
Gas generation supplied almost 73 per cent of all electricity

Figure 16 illustrates the average hourly generation from each technology over the past five years. Like the capacity factor calculation, this figure includes all assets with a capacity greater than 5 MW, including those self-supplying loads. As compared to the net-to-grid figure, the cogeneration assets show a much higher volume. Combined-cycle, simple-cycle, and “other” assets also have higher outputs but to a lesser extent. The difference between this figure and Figure 15 is the behind-the-fence generation.

In 2022, pure gas-generation technologies delivered 72.4 per cent of all generation in Alberta, up from 55 per cent in 2018. Coal generation provided 12.4 per cent, down from 35.1 per cent in 2018. Finally, renewable generation provided 12.6 per cent of Alberta’s generation, up from 7.3 per cent in 2018.

With respect to renewable generation, wind generation provided 8.8 per cent of the electricity generated in Alberta in 2022, compared to 7.6 per cent in 2021 and 5 per cent in 2018. Solar electricity was 1.4 per cent, up from zero in 2018. Finally, hydro provided 2.3 per cent, which is about average for the technology.

FIGURE 16: Annual average gross generation by technology



Achieved premium to pool price

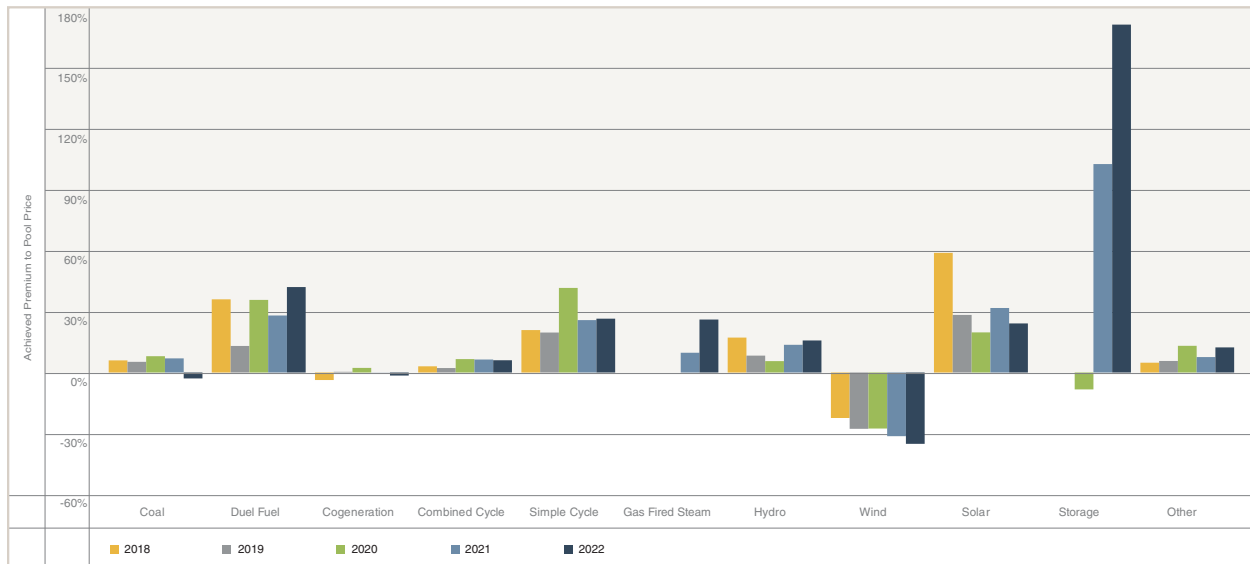
The offered price of power dictates a unit's position in the merit order, which, in turn, determines whether system controllers will dispatch the unit to run. Market participants choose offer prices based on the operational characteristics of the unit, the price of fuel, as well as other economic considerations 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 most 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 volume-weighted average of the hourly pool price, where the price in each settlement interval is weighted by the net-to-grid generation volume in that interval. A 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 17 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 cogeneration, realize achieved premiums near zero. Generation technologies that operate primarily in higher-priced hours—for example, simple-cycle or solar—realize positive achieved-premiums-to-pool price, while those that tend to operate in lower-priced hours, such as wind, realize achieved discounts- (or negative achieved premiums) to-pool price.

FIGURE 17: Annual achieved premium to pool price



Optimally, baseload generation technologies operate constantly 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 2022, cogeneration and coal-fired technologies realized a two and three per cent, respectively, deficit-to-pool price, as their energy was offered in as baseload. Combined-cycle realized a six per cent premium-to-pool price. A majority of energy for this type of unit is economic at low prices, while a smaller portion requires higher prices to be economic. Dual-fuel units, because of their gas component, had more flexibility than pure coal units and achieved a 43 per cent premium.

Peaking-generation technologies achieve greater operational flexibility than baseload generation. The combustion turbines used in simple-cycle or gas-fired-steam 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 and gas-fired-steam generation achieve some of the highest premiums across all generation technologies in Alberta. In 2022, simple-cycle units received a 27 per cent premium- to-pool price, while gas-fired-steam achieved a 26 per cent premium. 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 2022, storage units achieved a 174 per cent premium-to-pool price.

Wind generation is the only technology that consistently received a discount-to-pool price over the past five years—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, as the output of wind power varies according to environmental conditions. In addition, the strongest winds typically occur in the overnight hours, leading to the highest wind production occurring during the lowest-priced hours.

When wind blows in a particular 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, it replaces some quantity of power from higher-priced generating units in the energy market merit order, and thus tends to reduce the system marginal price. This, in turn, lowers its achieved price. In 2022, wind generation received a 36 per cent discount-to-the-pool price.

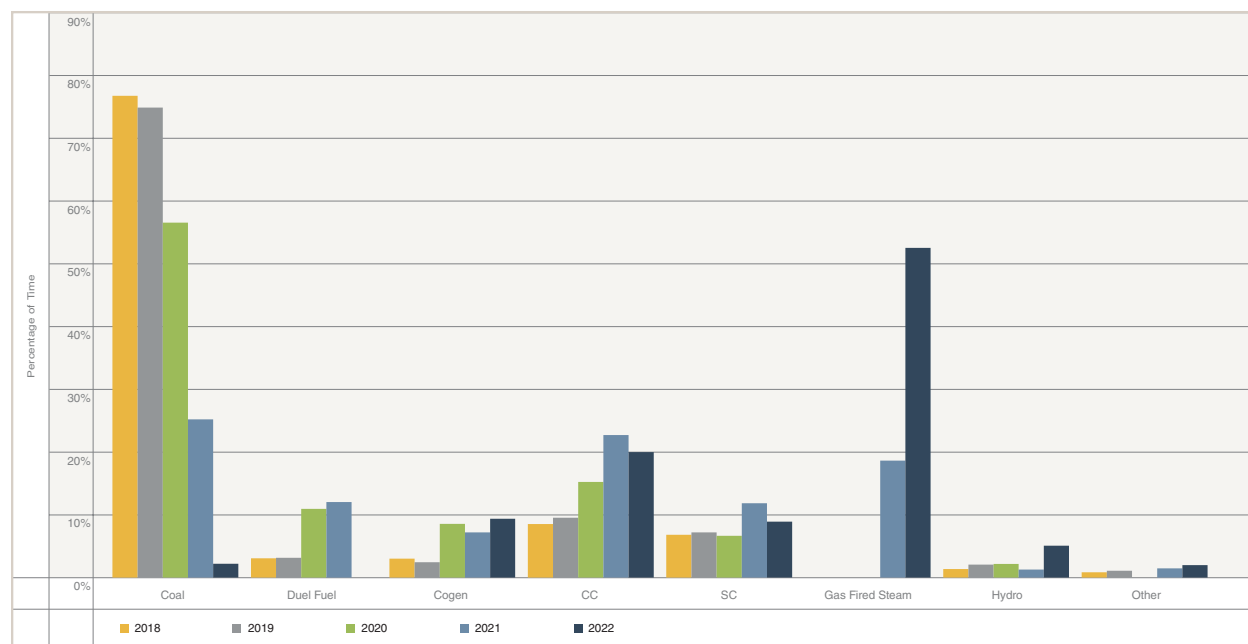
Solar power is like wind power, in that it cannot control its operational schedule because it is dependent on environmental conditions. However, since the highest-priced hours are typically during on-peak hours when the sun is shining, solar power typically receives an achieved price premium. In 2022, this premium was 25 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 2022, hydro received a 16 per cent premium-to-pool price.

Gas-fired-steam generation set marginal price in 52 per cent of hours

Figure 18 illustrates how frequently each generation technology set the system marginal price in each of the last five years. In 2022, pure gas-fired generation, which includes combined-cycle, cogeneration, simple-cycle, and gas-fired-steam, was on the margin 91 per cent of the time, compared to only 18 per cent in 2018. Coal generation, including dual fuel, was only on the margin two per cent of the time in 2022. In 2018, it was on the margin 77 per cent of the time. The decline in coal-fired generation on the margin is due to the remaining coal units being primarily price-takers. The specific gas generation technology that was on the margin the most was gas-fired-steam, at 52 per cent of 2022 hours.

FIGURE 18: Annual marginal price-setting technology



Supply adequacy

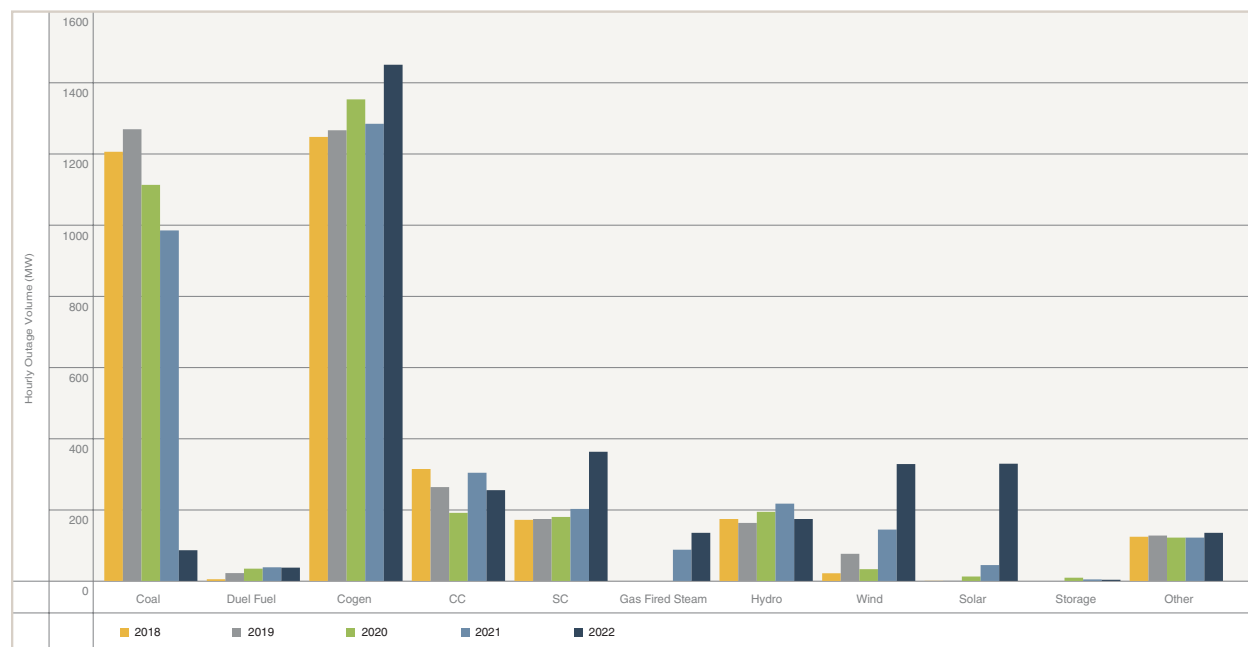
Supply adequacy expresses the ability of the system to serve load and system losses. In general, supply adequacy increases as generation capability increases, and decreases as system load increases. This report evaluates supply adequacy using two common measures: supply cushion and reserve margin. An in-depth analysis of future supply adequacy is provided on the AESO website in the quarterly *Long-Term Adequacy Metrics* report.¹⁰

Generation outages were 4 per cent lower year-over-year

The volume of generation outages is a primary driver of the supply cushion, as outages 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. Assets that are completely behind-the-fence at a self-supplied site, and do not offer into the electricity market, are not included in the calculation.

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 19: Annual hourly average generation outages by fuel type



In 2022, the overall average hourly outage volume decreased by approximately 130 MW, or four per cent, compared to 2021. Coal technology saw a year-over-year drop in outages of just over 900 MW. This was due primarily to a drop in average capacity of over 2,000 MW. With most of the coal units now converted to gas or retired, there were minimal major maintenance outages or derates at the remaining units.

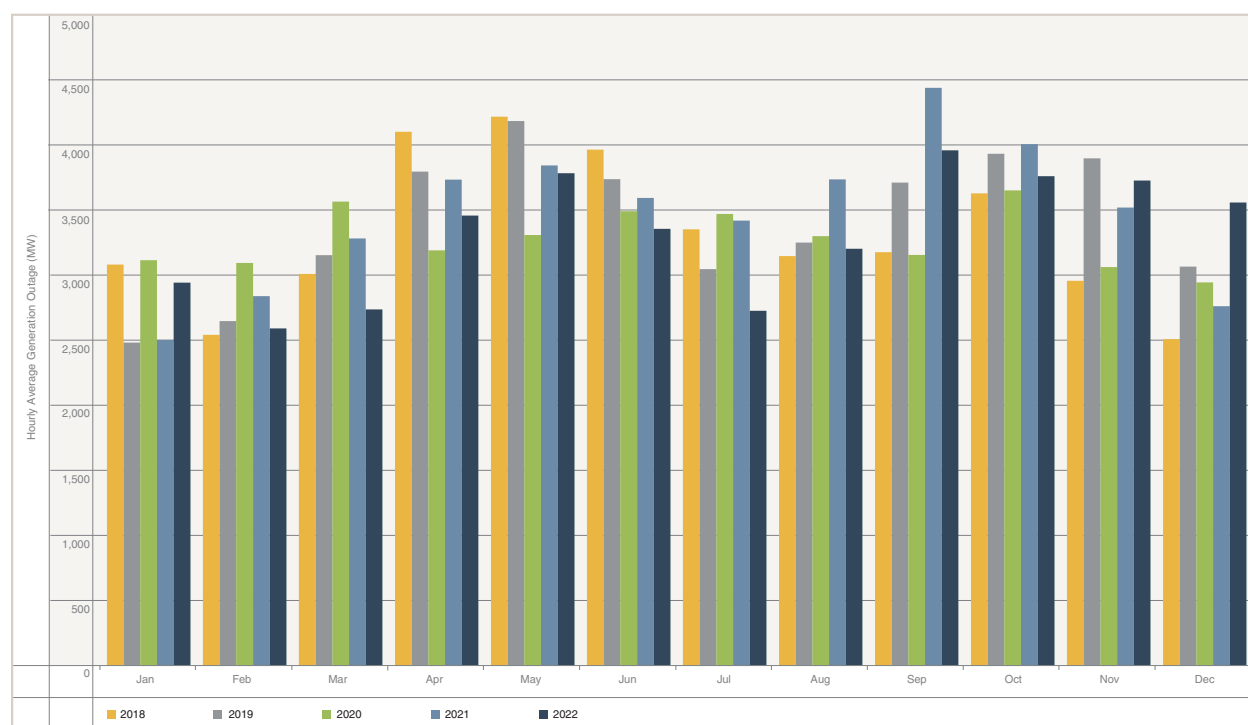
¹⁰ <https://www.aeso.ca/market/market-and-system-reporting/long-term-adequacy-metrics/>

In the outage calculation, assets that have energized their connection to the grid, but haven't completed their commissioning, are still considered online. If the asset is not generating power because it's not fully commissioned, that capacity is still counted as an outage. In 2022, this was the primary reason outages for the wind and solar technologies were a combined hourly average of 470 MW higher year-over-year. Between the two technologies, roughly 1,750 MW of new projects connected to the grid in 2022. However, many of the new projects were not immediately capable of generating at full capacity.

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. In 2022, the large increase in November and December was related to a large volume of renewable projects that connected to the grid but couldn't immediately operate at full capacity.

Figure 20 shows the hourly average generation outage volume by month for the last five years.

FIGURE 20: Generation outages by month



Supply cushion decreased 12 per cent

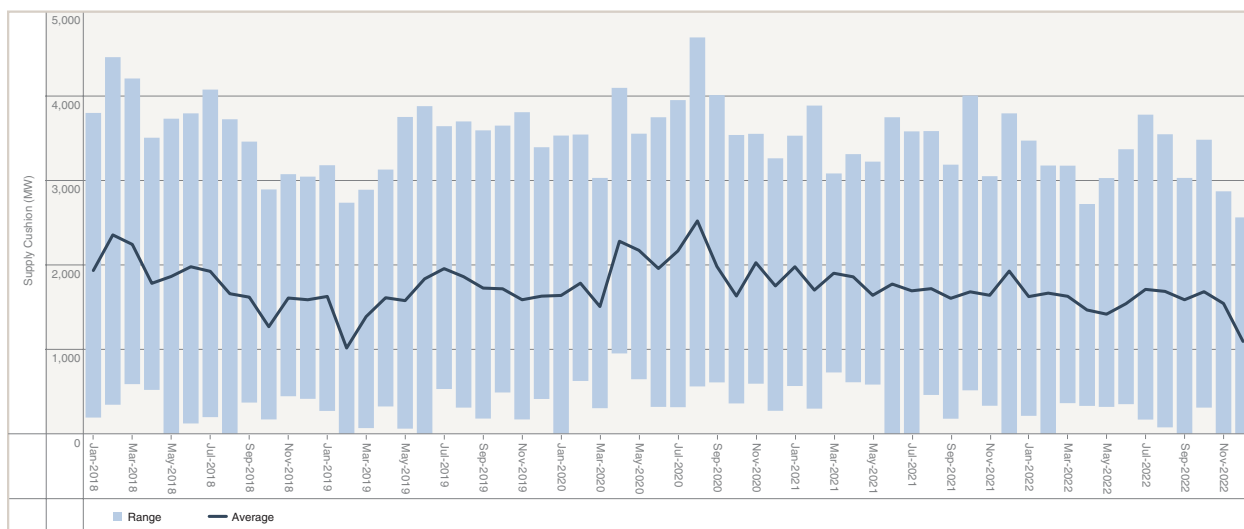
The hourly supply cushion represents the additional energy in the merit order that remains available for dispatch after load is served. Large supply cushions indicate greater reliability because more energy remains available to respond to unplanned outages or unexpected increases in demand. In 2022, the average supply cushion decreased 234 MW (roughly 12 per cent) from its 2021 value to 1,530 MW. The main reasons were the retirement of two former coal units, the long-term loss in September of 200 MW from a gas unit, and increased demand, especially during periods with extreme weather. In December, the average supply cushion was over 800 MW lower, as compared to 2021, when the frigid temperatures increased demand and lowered availability on some gas units, due to restrictions in natural gas availability.

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 a Grid Alert¹¹ if dispatches have been issued for all operating blocks in the energy market merit order, operating reserves requirements are 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 2022, Grid Alert events were declared seven times. There were two in September, one in November, and four in December, including two different events on Dec. 21. There were multiple contributing factors when these events occurred, including intertie outages, thermal generation outages and/or derates. However, high demand due to seasonally extreme temperatures and low wind generation accompanied each event.

Figure 21 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 21: Monthly supply cushion



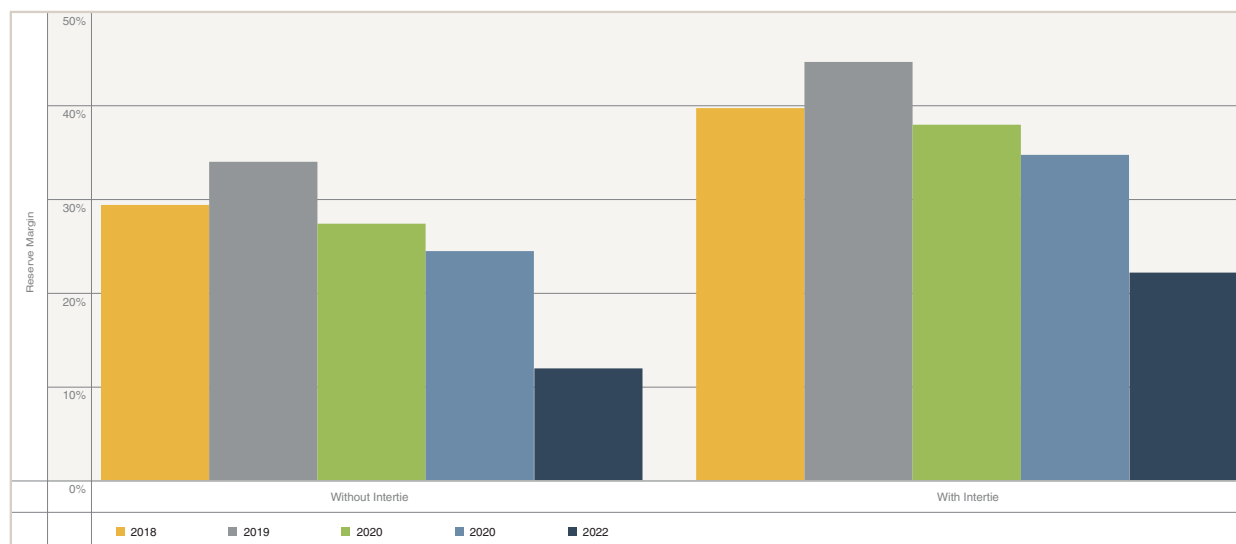
Reserve margin decreased by 12 per cent

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 22 shows the annual reserve margin over the past five years. In 2022, the annual reserve margin was 12 per cent without the intertie and 22 per cent with the intertie. Both metrics were down 12 per cent compared to 2021. The year-over-year decrease in the reserve margin was a result of approximately 670 MW less installed thermal unit capacity at year-end and an increase in the peak system load of approximately 460 MW.

¹¹ <https://www.aeso.ca/rules-standards-and-tariff/iso-rules/section-305-1-energy-emergency-alerts/>

FIGURE 22: Annual reserve margin



Wind generation

Wind generation served 8 per cent of Alberta internal load

Table 4 summarizes the annual statistics for wind generation. A total of 10 new wind facilities, with a combined capacity of 1,349 MW, came online in 2022. This increased the total capacity for wind to 3,618 MW at the end of the year. This represented 20 per cent of the total installed generation capacity in Alberta. Wind generation produced over eight per cent of total AIL in 2022. The capacity factor of wind generation fell to 33 per cent, down from 36 per cent in 2021, primarily due to many units that connected to the grid but did not immediately start generating. Excluding these new units, the capacity factor was closer to 38 per cent.

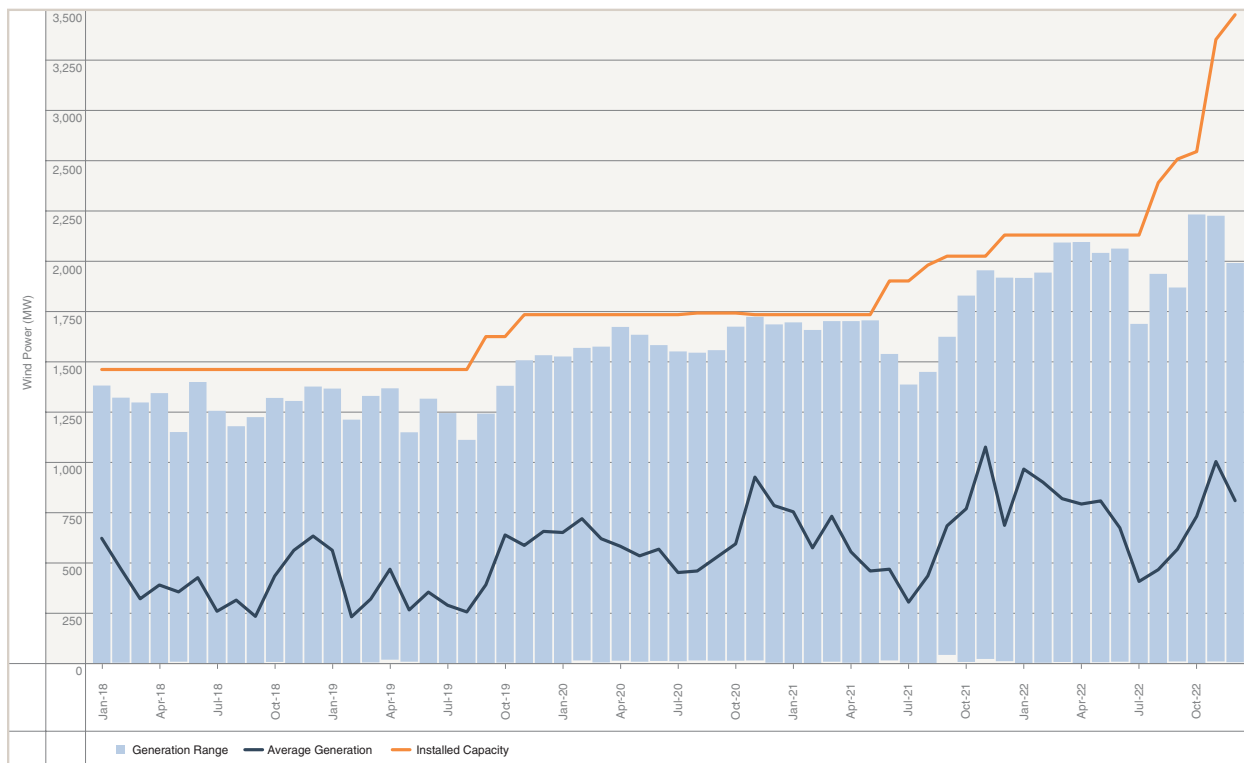
TABLE 4: Annual wind generation statistics

Year	2018	2019	2020	2021	2022
Installed wind capacity at year end (MW)	1,445	1,781	1,781	2,269	3,618
Total wind generation (GWh)	4,104	4,116	6,079	6,133	7,314
Wind generation as a percentage of total AIL	5%	5%	7%	7%	8%
Average hourly capacity factor	32%	30%	39%	36%	33%
Maximum hourly capacity factor	96%	94%	96%	95%	91%
Wind capacity factor during annual peak AIL	9%	0%	8%	16%	17%

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 23 shows the installed wind generation capacity and range of hourly wind generation over each month. As can be seen in the figure, all of the new wind projects connected in the second half of 2022, with the bulk connecting from October to year-end. A new record for wind generation was set on Oct. 26, 2022, at 2,208 MW. However, the record for monthly average generation remains the 1,208 MW set in November 2021.

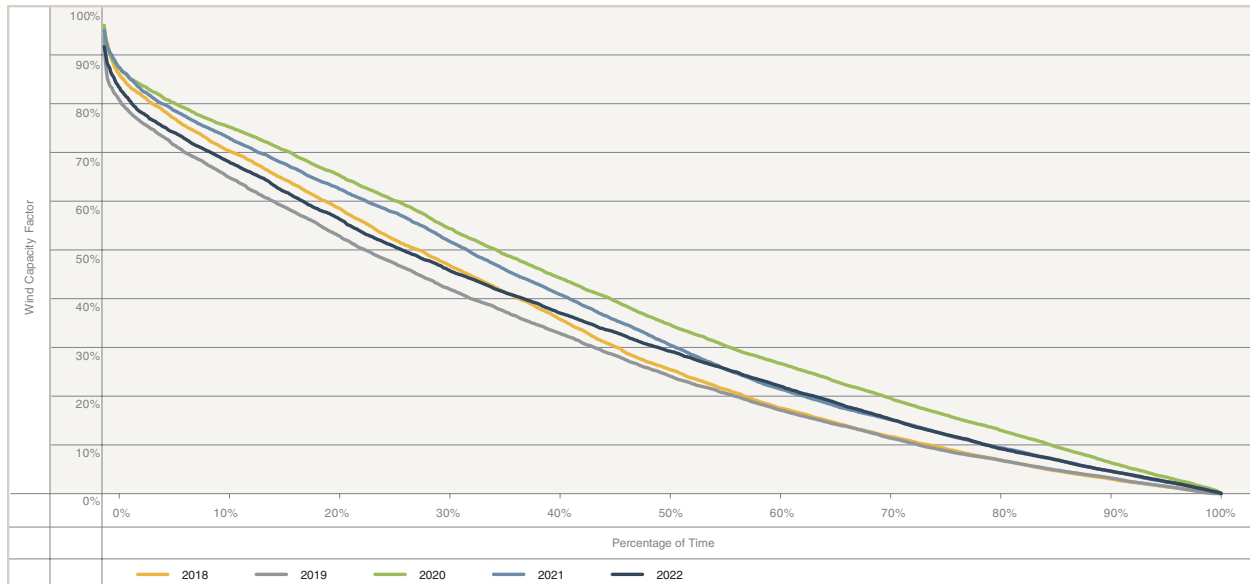
FIGURE 23: Monthly wind capacity and generation



Wind capacity factor decreased due to commissioning activities

Figure 24 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 24: Annual wind capacity factor duration curves

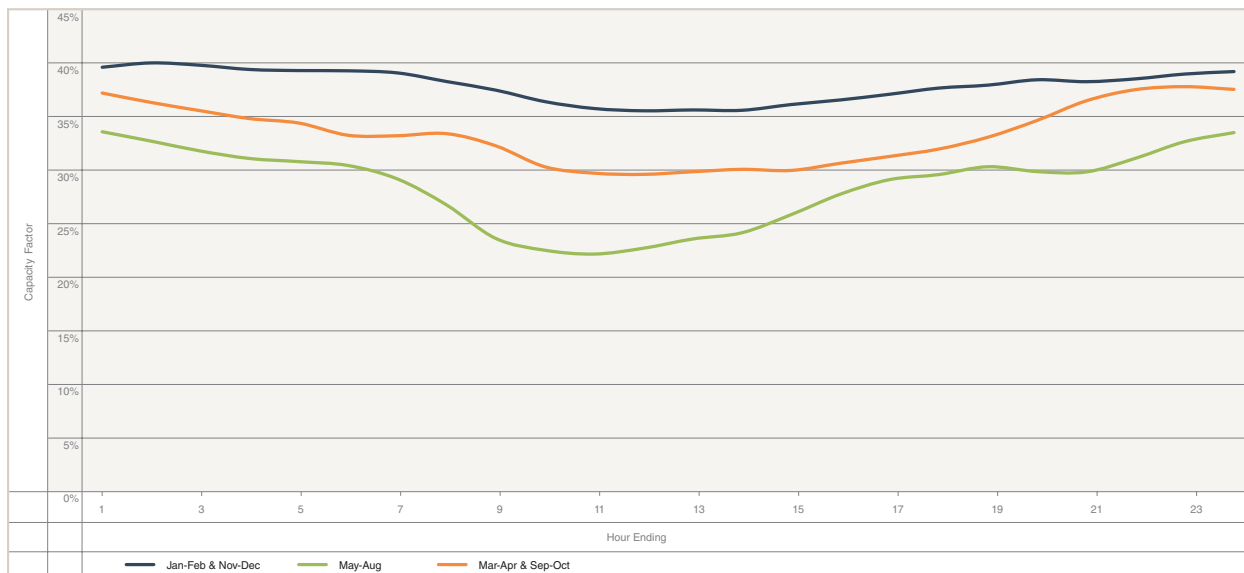


The duration curve for the capacity factor of wind generation decreased again in 2022, averaging 33 per cent compared to 36 per cent in 2021. A key reason for the lower capacity factor can be attributed to minimal output from the new wind farms for several months after they were declared in-service. Combined, the new projects that came online in 2022 had an average a capacity factor of just over six per cent and an average availability factor of only 22 percent.

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 the average hourly capacity factor of wind generation for different seasons of the year during 2022. 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 five to 14 per cent higher in the winter than the summer. The winter capacity factor was the most heavily impacted by the connection of the new assets and was almost six per cent lower than that seen in 2021.

FIGURE 25: 2022 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 wind facilities in central Alberta has increased the geographic diversification of wind generation. In 2022, there were four new facilities connected in central Alberta, bringing the total to eight. At the end of 2022, wind generation capacity totaled 2,779 MW in southern Alberta and 839 MW in central Alberta.

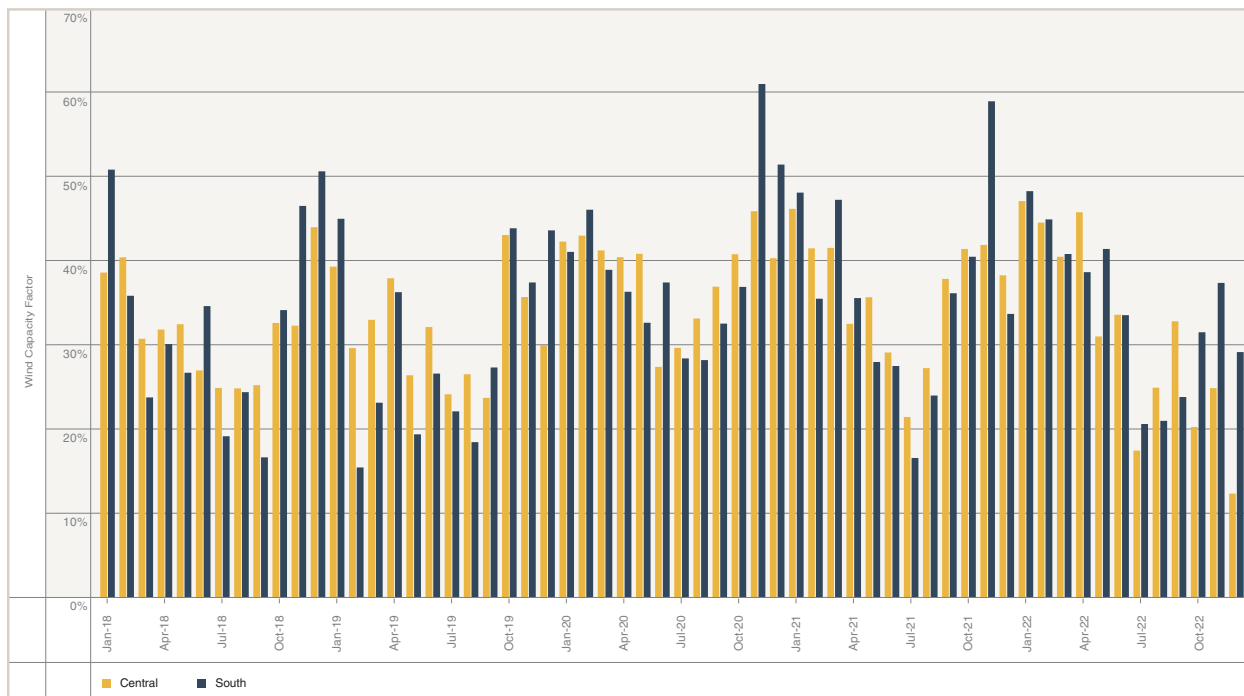
Table 5 shows regional wind generation statistics for 2022. The average capacity factor was higher for assets in the Central region, as was the achieved price. As a result, wind facilities in the Central region tended to earn more, per megawatt of capacity than those in the South region.

TABLE 5: 2022 regional wind statistics

Region	Central	South	Total
Installed wind capacity at year end (MW)	839	2,779	3,618
Total wind generation (GWh)	830	6,484	7,315
Average wind capacity factor	36%	34%	34%
Achieved price (\$/MWh)	\$125.42	\$101.74	\$104.43

Figure 26 shows the monthly average capacity factor by region in the past five years. The capacity factors in the latter half of the year are lower year-over-year due to the new wind farms connecting to the grid but not generating. 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 26: Monthly wind capacity factor by region



Solar generation

During 2022, 17 new solar farms joined the generation fleet, adding 337 MW of new capacity. In addition, the Travers solar farm was updated from 400 MW to 465MW. In total, 402 MW of new capacity was connected to the grid. The new assets were added throughout the year and took varying amounts of time to begin generating electricity. 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. The highest hourly generation for solar occurred on Oct. 7, 2022, at 826 MW. Figure 27 illustrates the monthly average on-peak generation of the solar fleet for the last five years. Off-peak hours are excluded, as there is limited solar generation during those hours.

FIGURE 27: Monthly average on-peak solar capacity and generation

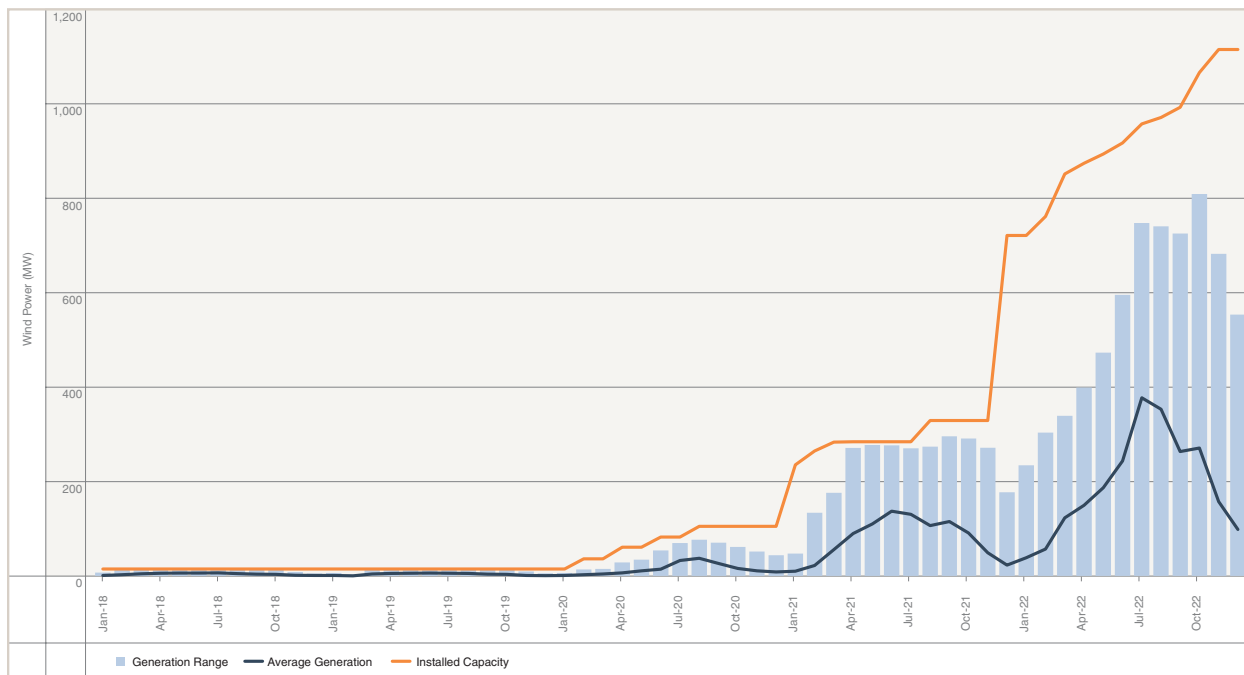
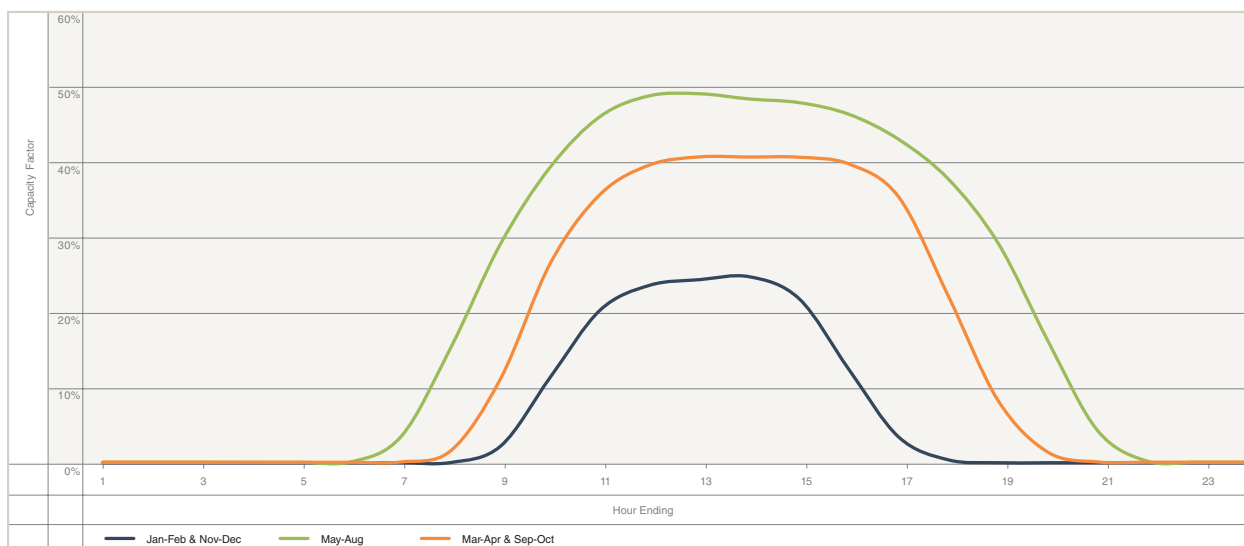


Figure 28 shows the average hourly output of solar generation for different periods of the year during 2022. Peak generation occurs between 10 a.m. to 3 p.m., with the summer and shoulder months seeing a couple of extra hours of peak generation in the morning and early evening. The average capacity factors are lower than normal due to assets connecting to the grid but not being able to generate immediately.

FIGURE 28: 2022 seasonal average hourly output of solar fleet



Imports and exports

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

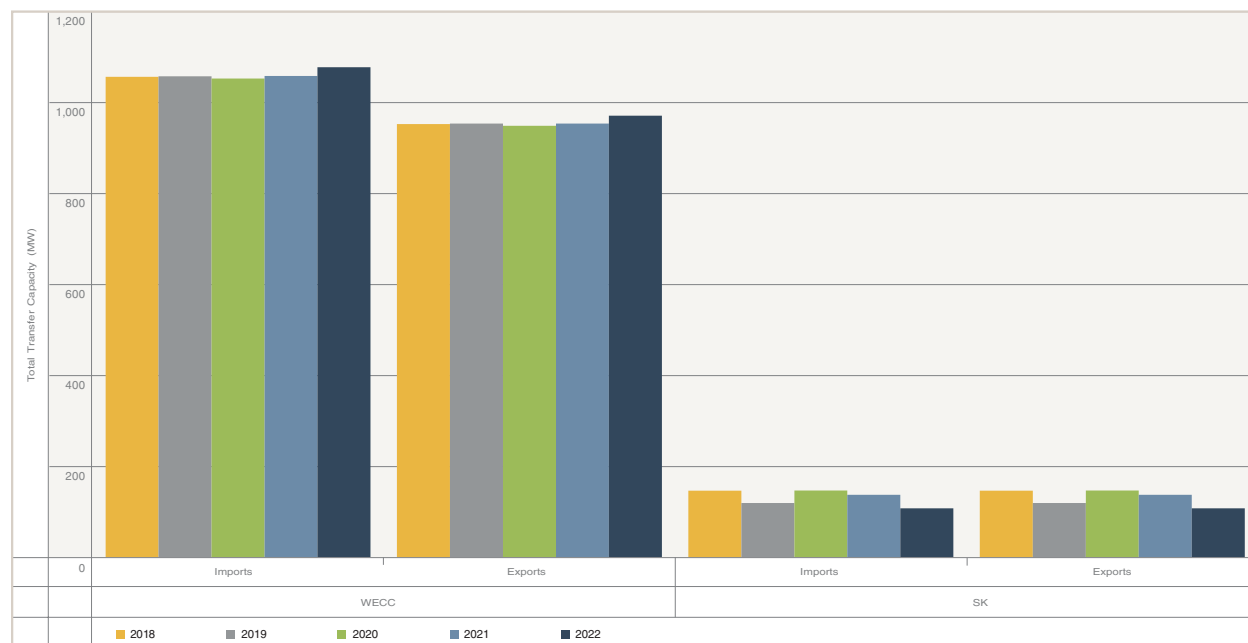
Transfer path rating remained stable

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 29 shows the average TTC in each year between Alberta and other WECC members, and between Alberta and Saskatchewan. The TTC rating for WECC members increased by two percent, while the Saskatchewan TTC decreased by 22 percent relative to 2021. The significant drop in the Saskatchewan TTC was due to outages that occurred during several periods of the year. The outage left the Saskatchewan intertie derated to 60 MW for the majority of the last four months of the year.

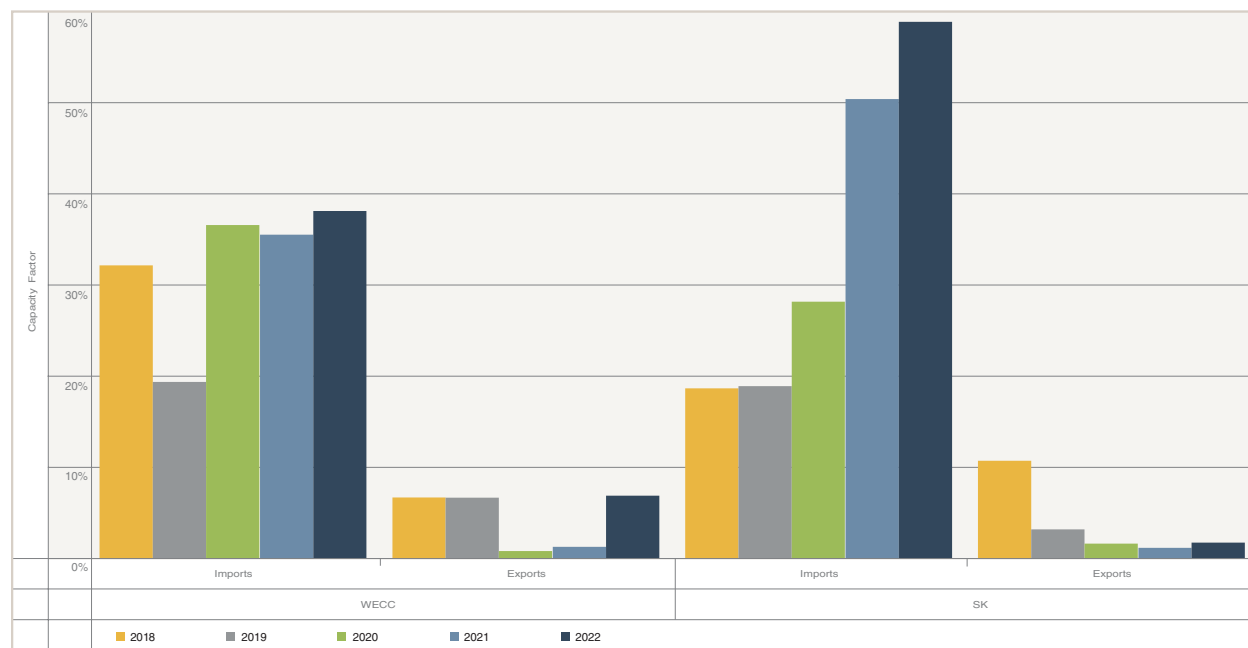
FIGURE 29: Average annual path rating by transfer path



Intertie capacity factors

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. Figure 30 shows the annual capacity factor for transfers between Alberta and other WECC members, and between Alberta and Saskatchewan. The overall transfer of energy between Alberta and Saskatchewan was lower in 2022 compared to 2021, but the capacity factor is inflated due to derates and outages on the Saskatchewan transfer path that lowered TTC.

FIGURE 30: Annual capacity factor by transfer path



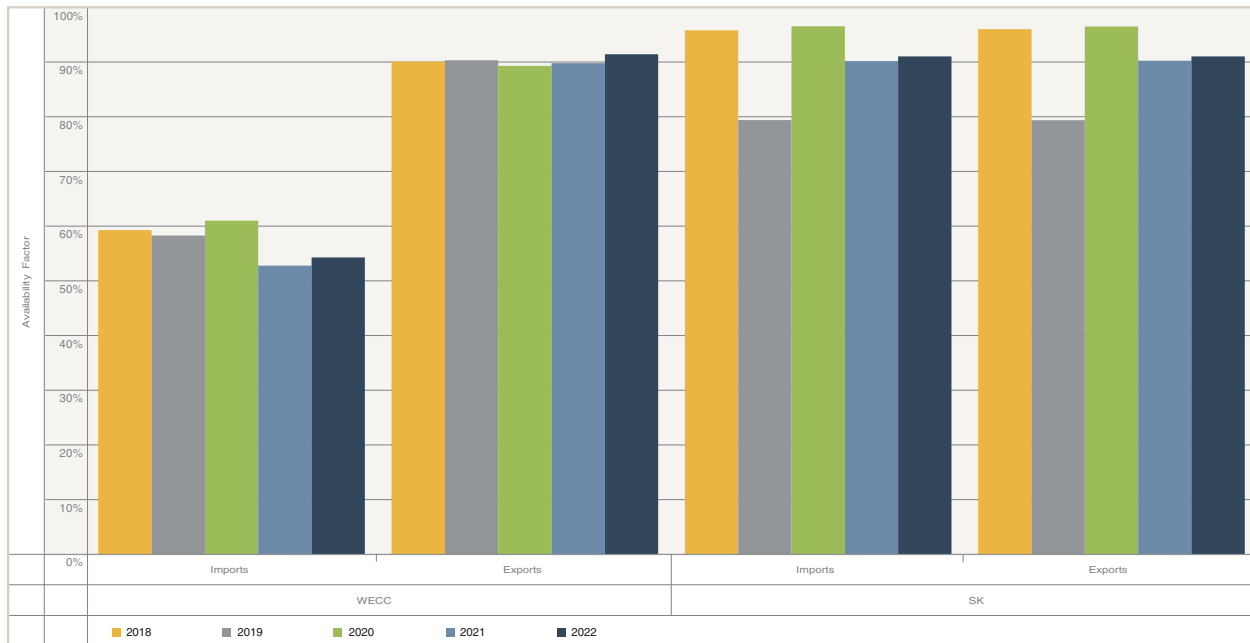
Intertie availability factor

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 31 illustrates the annual availability factor for transfers between Alberta and other regions. In 2021 and 2022, the WECC transfer path had a reduced availability factor compared to 2020 primarily due to the lower availability of volume from Load Shed Service for imports (LSSi) contracts.¹² On the Saskatchewan transfer path, a long-term maintenance outage in 2021 and 2022 reduced the availability factor compared to 2020.

¹² 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 31: Annual availability factor by transfer path



Availability utilization

Availability utilization is the percentage of available transfer capability (ATC) used to transfer energy between jurisdictions. Availability utilization is calculated as the ratio of transferred energy to the ATC of the transfer path. Figure 32 illustrates the annual availability utilization for energy transfers between Alberta and other WECC members, and between Alberta and Saskatchewan. In 2022, WECC import utilization increased by three per cent compared to 2021. The export utilization rate remained weak along the Saskatchewan transfer path but recovered by six percent on the WECC transfer path. High power prices in Alberta, relative to surrounding jurisdictions, were largely behind the increase in imports. Strong power prices in California and the Pacific Northwest region towards the end of the year were the main contributors to the recovery in exports compared to 2020 and 2021.

FIGURE 32: Annual availability utilization by transfer path

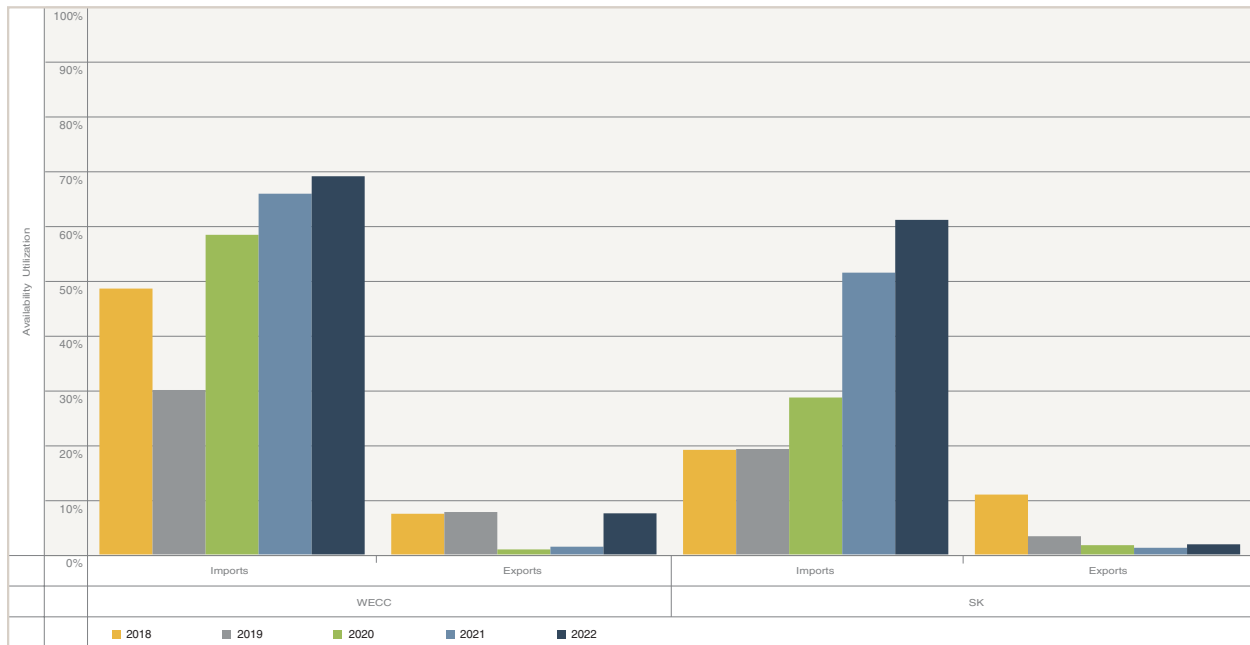


Figure 33 shows the annual interchange utilization between Alberta and the WECC regions over the past five years. In this chart, the interchange utilization represents the ratio of net imports or exports to the intertie's ATC. Imports include any volume of operating reserve procured on the intertie. The utilization calculation reflects the combined operating limit of the B.C. and Montana interties and the Alberta system operating limit. In 2022, Alberta had net imports from the WECC region in just under 85 per cent of the hours and was a net exporter in 13 per cent of the hours. The increase in imports compared to previous years was driven by the strong pool prices experienced in 2022, while exports recovered to their 2018-2019 levels due to the strong demand from neighbouring jurisdictions.

FIGURE 33: Annual interchange utilization with WECC region

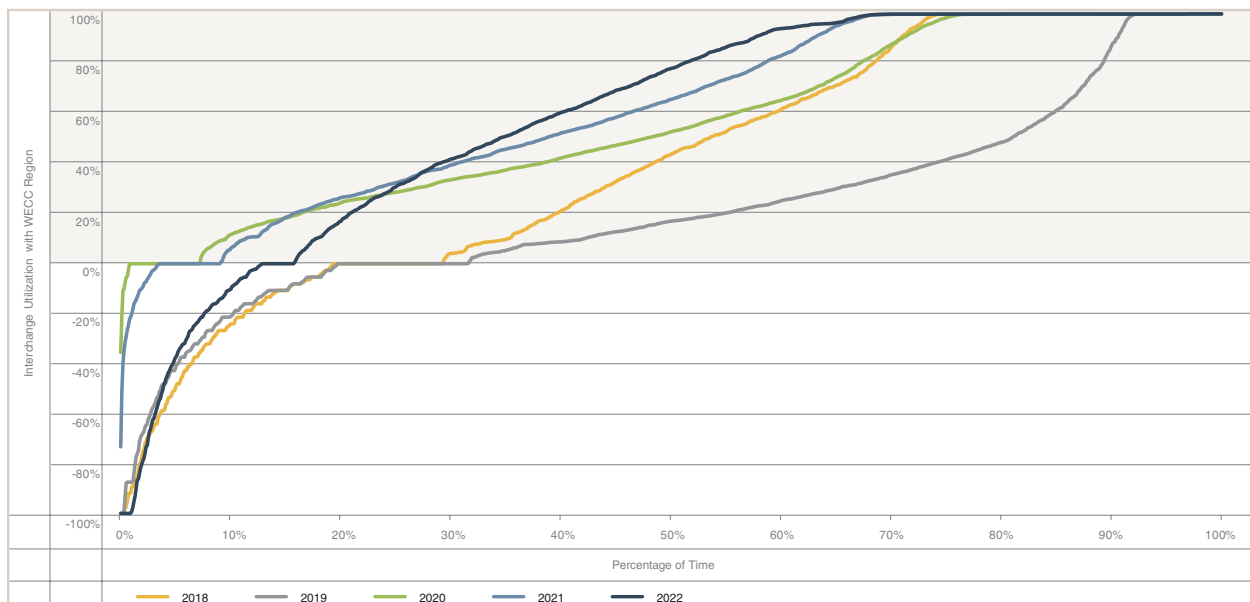
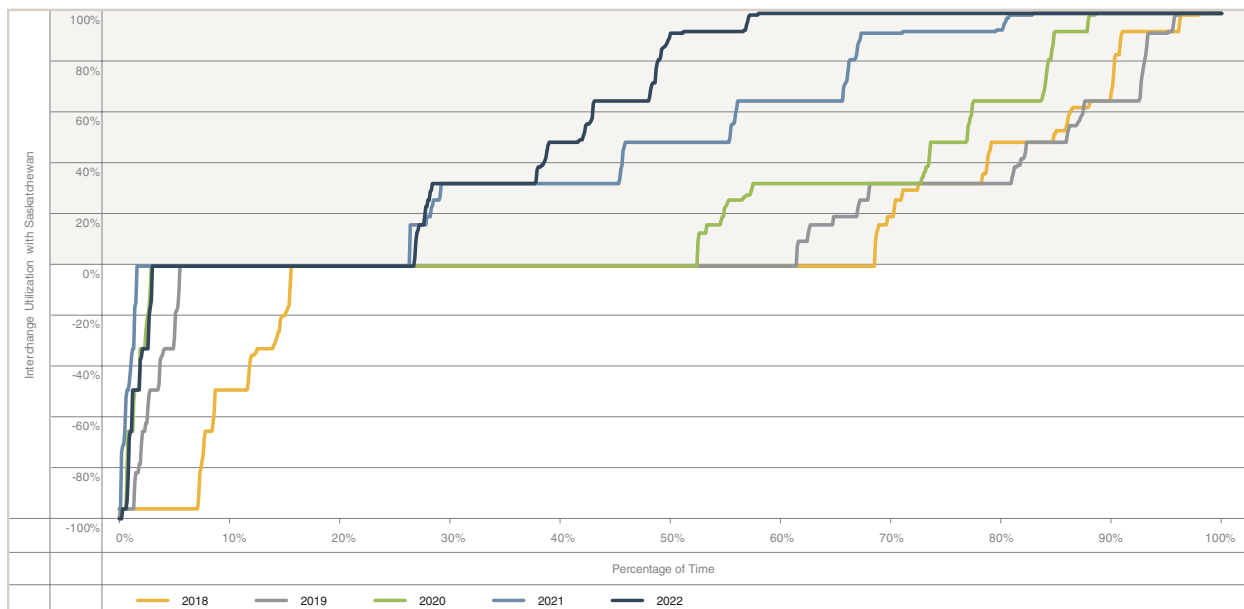


Figure 34 shows the annual interchange utilization between Alberta and Saskatchewan over the past five years. In 2022, Alberta imported energy from Saskatchewan in 73 per cent of the hours and exported energy in just under three per cent of the hours. As mentioned above, the utilization of the interchange increased in 2022 due to the lower TTC, but the overall transfer of energy between the two provinces was lower (check Figure 35).

FIGURE 34: Annual interchange utilization with Saskatchewan



Alberta remains a net importer

Figure 35 illustrates the annual average energy transferred from each province or state. Alberta has been a net importer since 2017. In 2022, imports from B.C. and Montana increased compared to previous years, largely due to the high pool prices in Alberta. Imports from Saskatchewan fell slightly due to intertie outages. Meanwhile, exports to Montana, B.C., and the western U.S. increased due to strong demand in those regions.

FIGURE 35: Annual intertie transfers by province or state

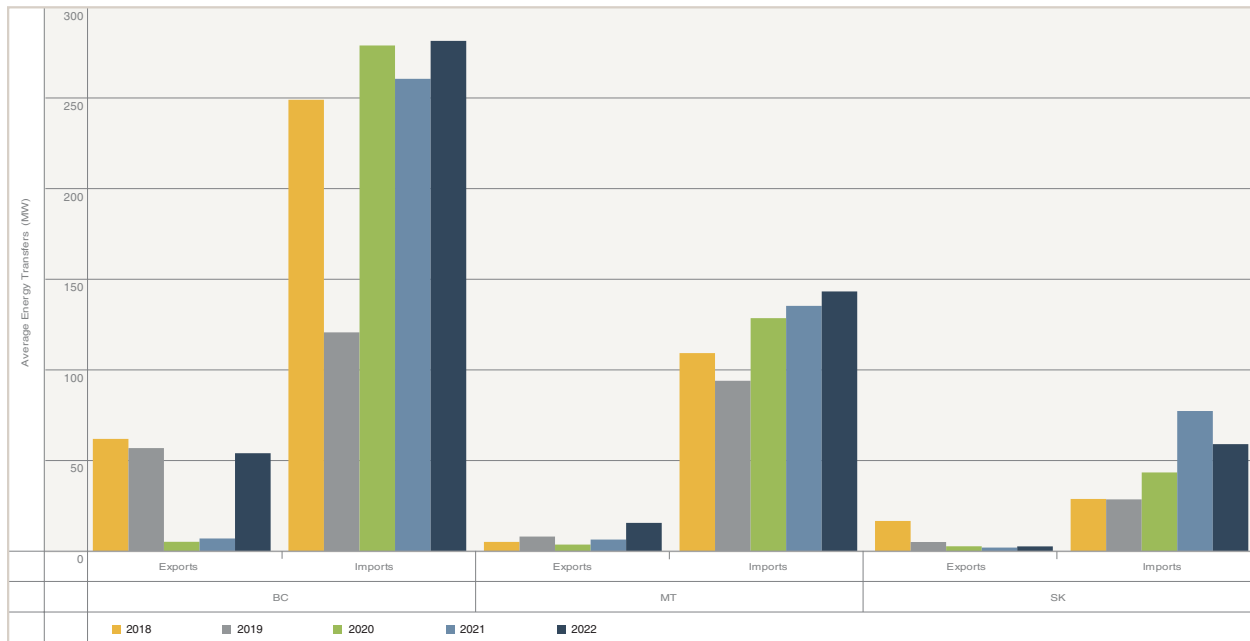
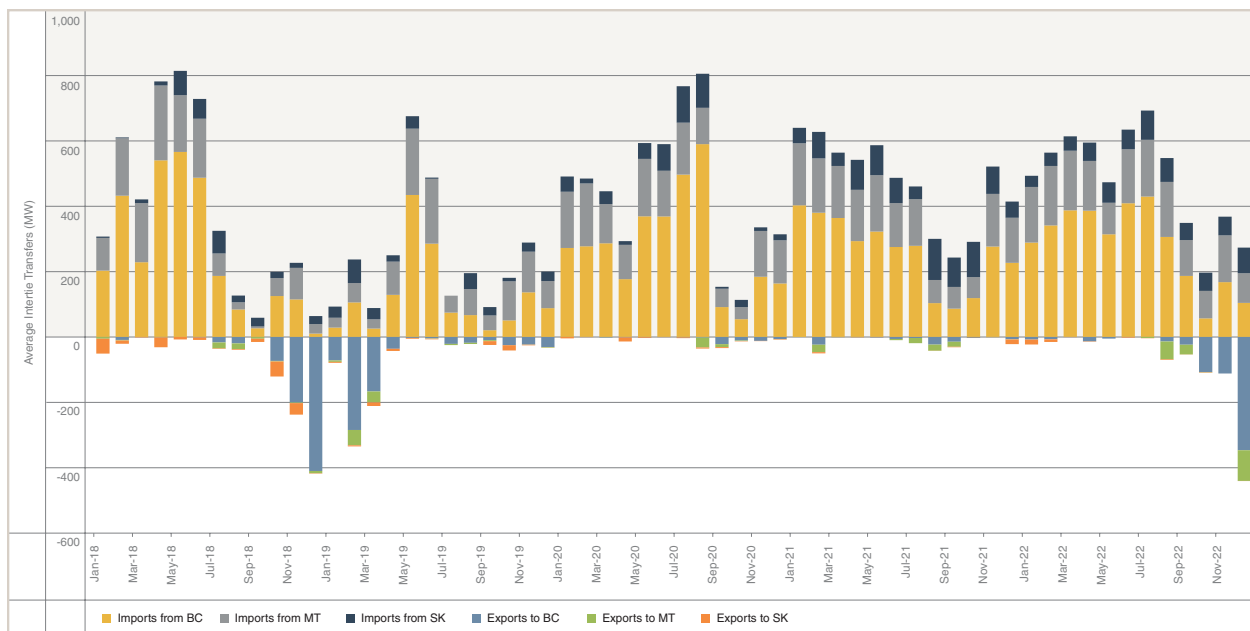


Figure 36 illustrates the monthly average energy transferred from each province or state. Positive values represent imports to the province and negative values represent exports to other jurisdictions. Strong power prices driven by high natural gas prices in the western U.S. and B.C. revived demand for Alberta energy in the last quarter of the year to levels previously experienced in 2018-2019.

FIGURE 36: Monthly average intertie transfers



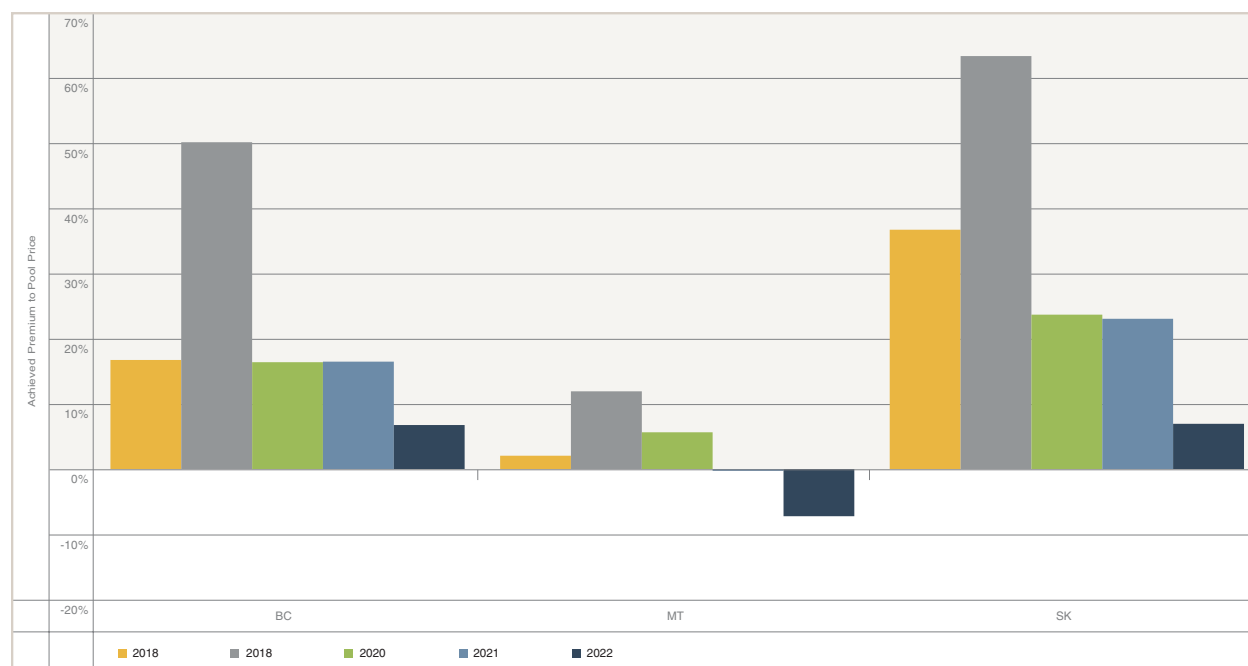
Achieved premium to pool price decreased

Figure 37 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 the 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 seven per cent premium, compared to 17 and 23 per cent, respectively, in 2021. The drop in the premium-to-pool price across these transfer paths can be attributed to the drop in import levels in the last quarter, when the pool price was at its highest. Usually, imports increase when pool prices are high in Alberta. However, increased demand and higher prices in surrounding jurisdictions made it more economical to export from Alberta during this period.

Imports from Montana received a discount to the yearly average pool price in 2022. In addition to the reason mentioned above, Montana was impacted by a correlation to the wind profile in the southern region of Alberta. Since, most power imports from Montana are wind-generated, strong imports from that jurisdiction tended to coincide with periods of higher wind generation in Alberta, thus receiving lower pool prices.

FIGURE 37: 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 reserves use 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 spinning reserves to provide 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 a 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 the 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 2022 was \$501 million, a 48 per cent increase from 2021. As explained above, active OR products are directly indexed to the pool price. While not directly indexed to the pool price, standby OR product prices are influenced by it. Therefore, the 59 per cent year-over-year increase in the pool price was the primary driver in the increase of OR costs.

TABLE 6: Annual operating reserve statistics

Year	2018	2019	2020	2021	2022
Volume (GWh)					
Active procured	5,802	5,640	5,561	5,624	5,719
Standby procured	1,971	2,124	1,940	1,191	994
Standby activated	343	180	348	156	179
Cost (\$-millions)					
Active procured	\$195	\$172	\$122	\$314	\$466
Standby procured	\$8	\$6	\$3	\$4	\$2
Standby activated	\$36	\$14	\$22	\$20	\$33
Total	\$240	\$193	\$148	\$339	\$501

Market share represents the percentage of total procured OR capacity provided by each technology of generation. Figure 38 illustrates the annual market share of active OR. In 2022, hydroelectric generation had the largest market share in the regulating and spinning products at 68 per cent and 59 per cent, respectively. Despite being fairly new to the market, storage assets had the second most market share of active spinning, at 17 per cent. Finally, load had the largest market share of the supplemental product at 45 per cent.

Figure 39 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 31 per cent of the standby regulating and 29 per cent of the spinning reserve markets. Simple-cycle has the biggest share of the standby supplemental market at 45 per cent, followed by hydro at 35 per cent. In these charts, dual-fuel assets are included with coal and gas-fired-steam assets and with simple-cycle assets.

FIGURE 38: 2022 market share of active operating reserve

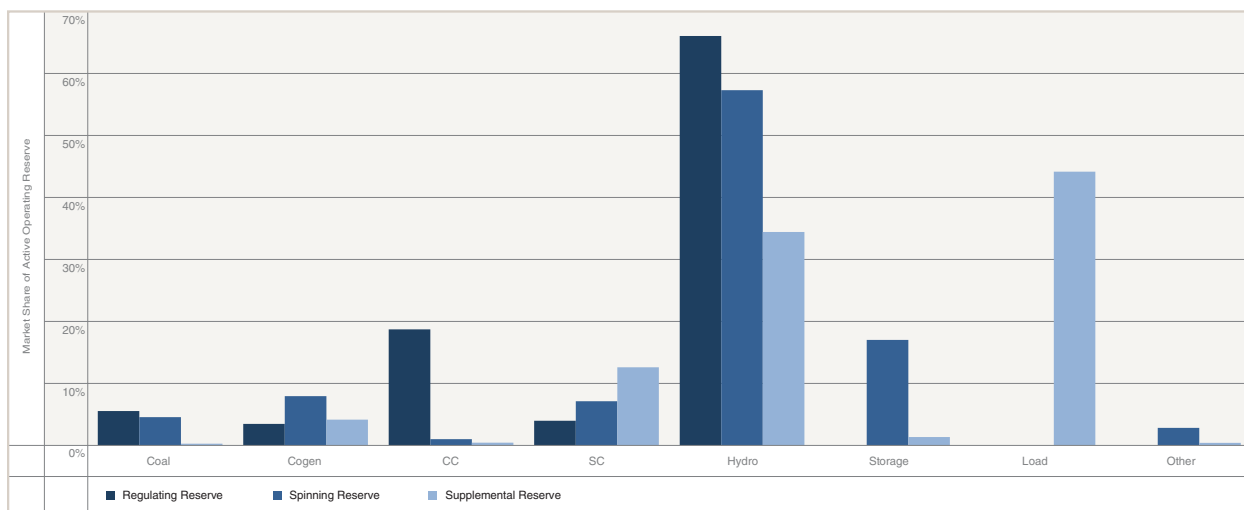
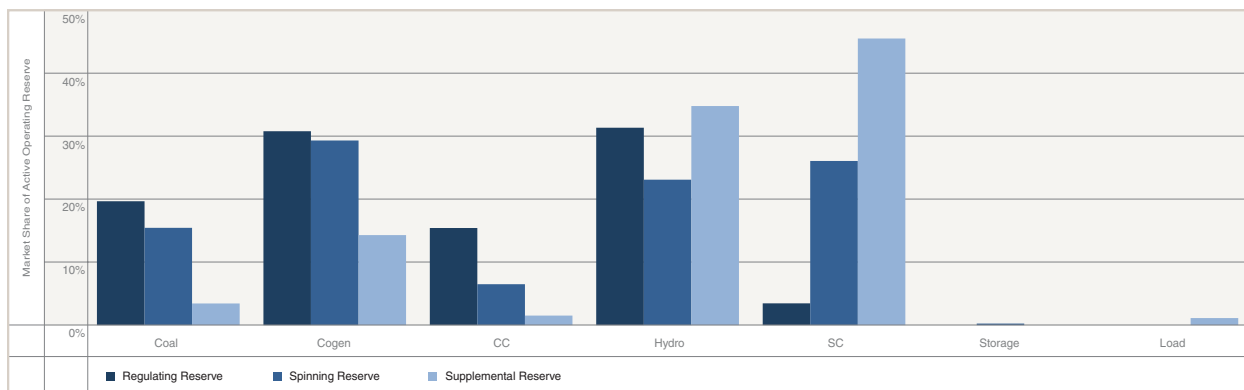


FIGURE 39: 2022 market share of standby operating reserve



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 2022, dispatched TMR energy was 23 GWh and costs were \$2.48 million.

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 megawatt level of energy provided by that eligible offer block to determine the amount of the transmission constraint rebalancing payment. In 2022, constraints on the transmission system required System Controllers to curtail 89 GWh of in-merit energy, and the TCR payments to market participants totaled approximately \$1.8 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 2022, DDS offset none of the dispatched TMR volume. DDS is a voluntary program and, in 2022, 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.¹³

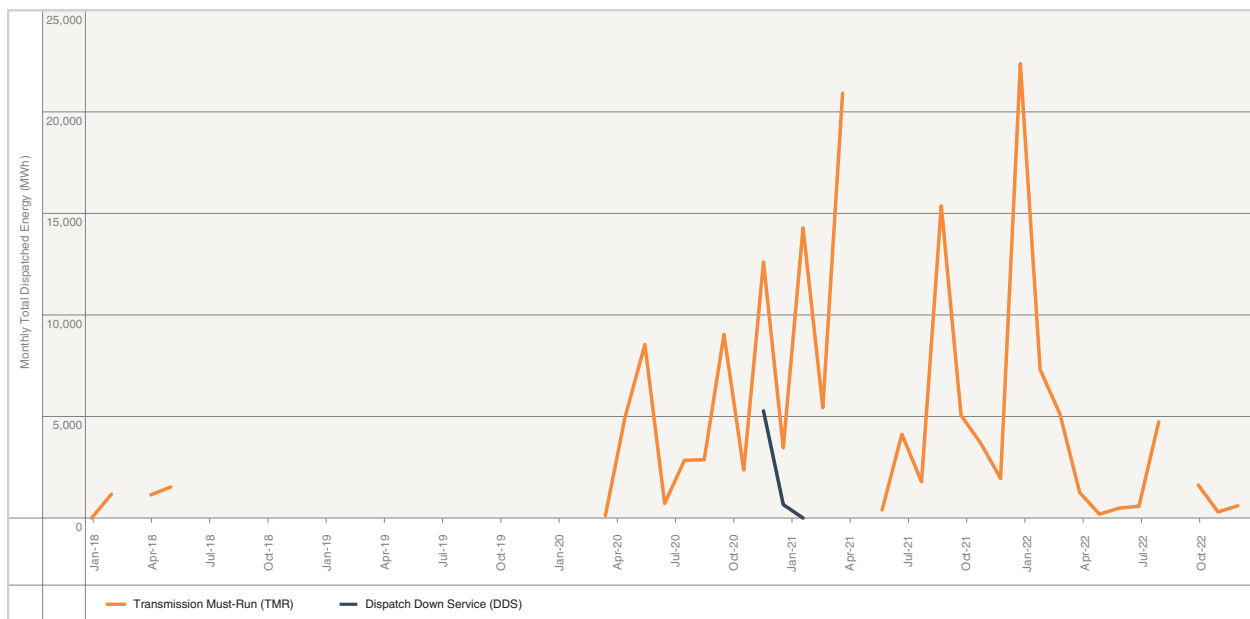
¹³ The TCM data has been prepared pursuant to subsection 4(2) of Section 302.1 of the ISO rules, Real Time Transmission Constraint Management (Section 302.1), which requires the Alberta Electric System Operator (AESO) to: “monitor and publicly report on the costs incurred as a result of mitigating transmission constraints on an annual basis.”

TABLE 7: Annual TMR and DDS statistics

Year	2018	2019	2020	2021	2022 ¹⁴
Transmission must-run					
Dispatched energy (GWh)	7	5	48	96	23
Contracted TMR costs (\$ millions)	\$0.01	\$0.04	\$0.67	\$0.01	\$0.02
Conscripted TMR costs (\$ millions)	\$0.43	\$0.26	\$0.73	\$5.69	\$2.48
Transmission constraint rebalancing					
Constrained-down generation (GWh)	3	4	72	69	89
Number of days with TCR payment	7	14	67	89	207
Total TCR payments (\$-millions)	\$0.04	\$0.27	\$0.52	\$2.65	\$1.80
Total annual TCM costs					
Annual TCM cost (\$ millions)	\$0.47	\$0.56	\$1.92	\$8.35	\$4.30
Dispatch down service					
Total payments (\$-millions)	\$0.00	\$0.01	\$0.16	\$0.00	\$0.00
Dispatched energy (MWh)	106	377	8,492	11	0
Average charge (\$/MWh)	\$13.21	\$17.24	\$18.84	\$19.58	\$0.00

Figure 40 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 40: Monthly TMR and DDS dispatched energy



¹⁴ Preliminary data

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	2018	2019	2020	2021	2022
Payments to suppliers on the margin					
Average range (\$/MWh)	\$8.18	\$12.36	\$5.89	\$24.99	\$38.08
Total PSM payments (\$-millions)	\$1.32	\$1.58	\$0.75	\$2.89	\$4.57

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.

In 2022, the total cost of PSM was \$4.57 million, up from \$2.89 million in 2021. 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 52 per cent to \$38.08/MWh in 2022, due to the significantly higher volatility and prices over the year.

Flexibility

The AESO assesses 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 fluctuations in demand and variable generation, which is referred to as net demand variability. Given changes occurring in Alberta's generation fleet, continued monitoring and periodic assessments of system flexibility to proactively identify when system flexibility may need to be enhanced is important. 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 associated 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 41 provides the frequency and size of 10-minute ramps of variable generation, AIL, and net demand in 2022. 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 megawatt or larger wind and solar assets in Alberta. Small-scale wind and solar generators (i.e., less than five megawatts) within the province are generally connected to the distribution system and their variability is captured in AIL.

In 2022, 97.1 per cent of all 10-minute net-demand ramps were within plus/minus 100 MW, down from 97.9 per cent of ramp periods in 2021. There were 187 10-minute periods where net-demand changed more than 150 MW in 2022, up from 91 such events in 2021. Figure 42 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. As more wind and solar generation is added to the grid, the frequency of larger net demand ramps is expected to continue to increase. For context, the reduction in net demand ramps of 30 MW or less was about three per cent of all 10-minute ramps in 2022. The distribution of variable generation ramps was higher than the distribution of AIL ramps. This shows that in 2022 variable generation were more volatile than AIL.

FIGURE 41: Distribution of 10-minute ramps for wind and solar generation, load, and net demand in 2022

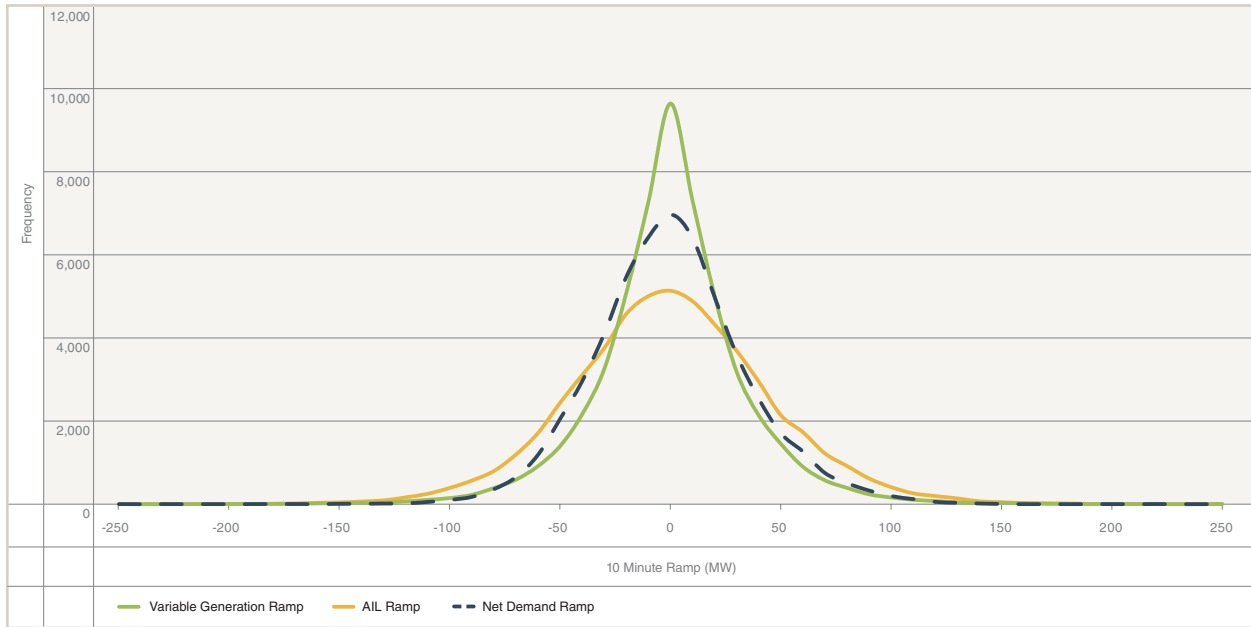
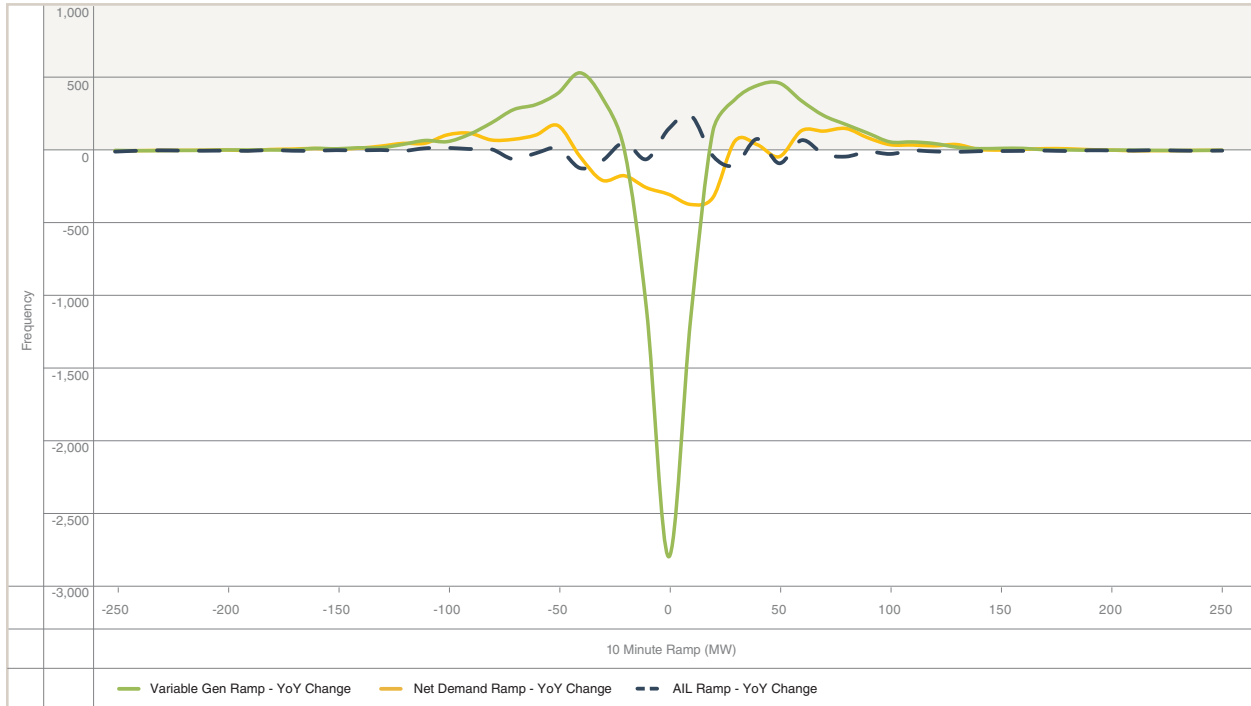


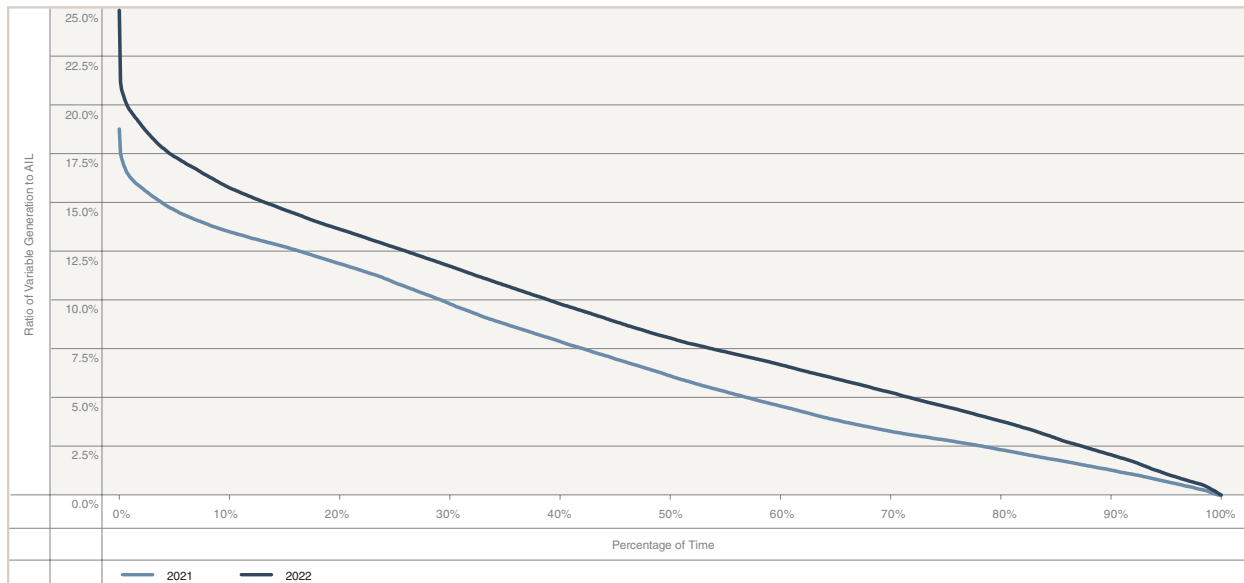
FIGURE 42: Distribution of year-over-year change in 10-minute ramps for wind and solar generation, load, and net demand



Variable generation-to-AIL ratio

As more variable wind and solar generation connects 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 43 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 2022, the highest ratio of variable generation to AIL was 28.1 per cent, compared to 21.2 per cent in 2021. The 90th percentile 10-minute periods had a ratio of 17.8 per cent in 2022 versus 15.2 per cent in 2021.

FIGURE 43: Ratio of variable generation-to-AIL



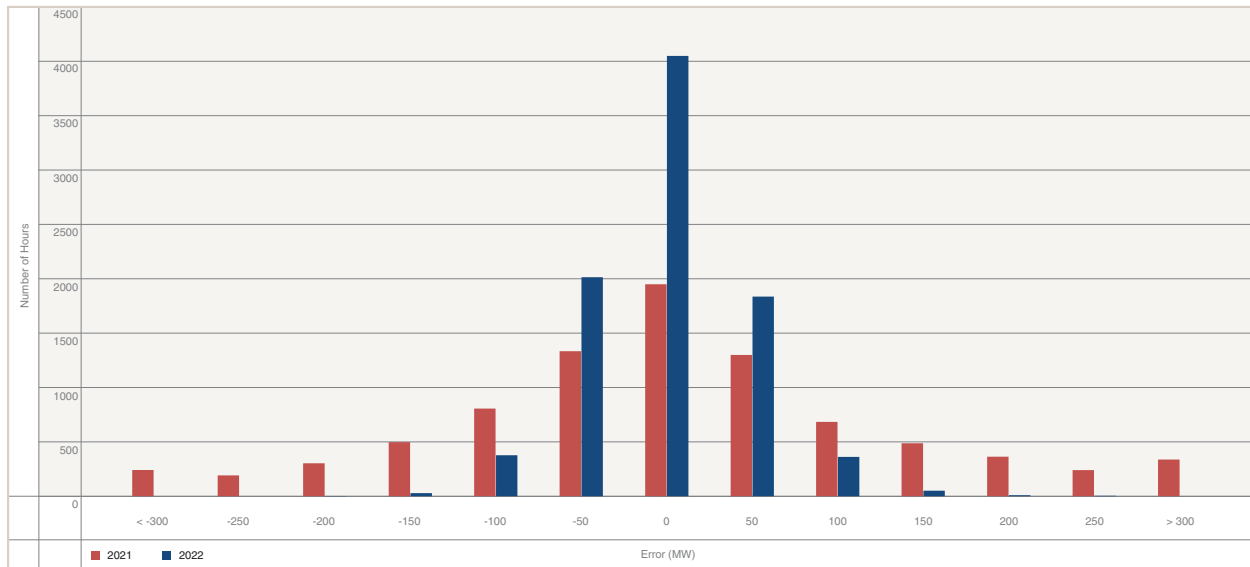
Forecast uncertainty

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 44 illustrates the distribution of the day-ahead load forecast error for all hours in 2022 compared to 2021. The error at a given hour is defined as the day-ahead forecast of AIL minus the actual AIL for that hour. In 2022, the mean absolute per cent error (MAPE) was 0.70 per cent, an improvement from 0.88 per cent in 2021.

FIGURE 44: Distribution of day-ahead load forecast in 2021 and 2022



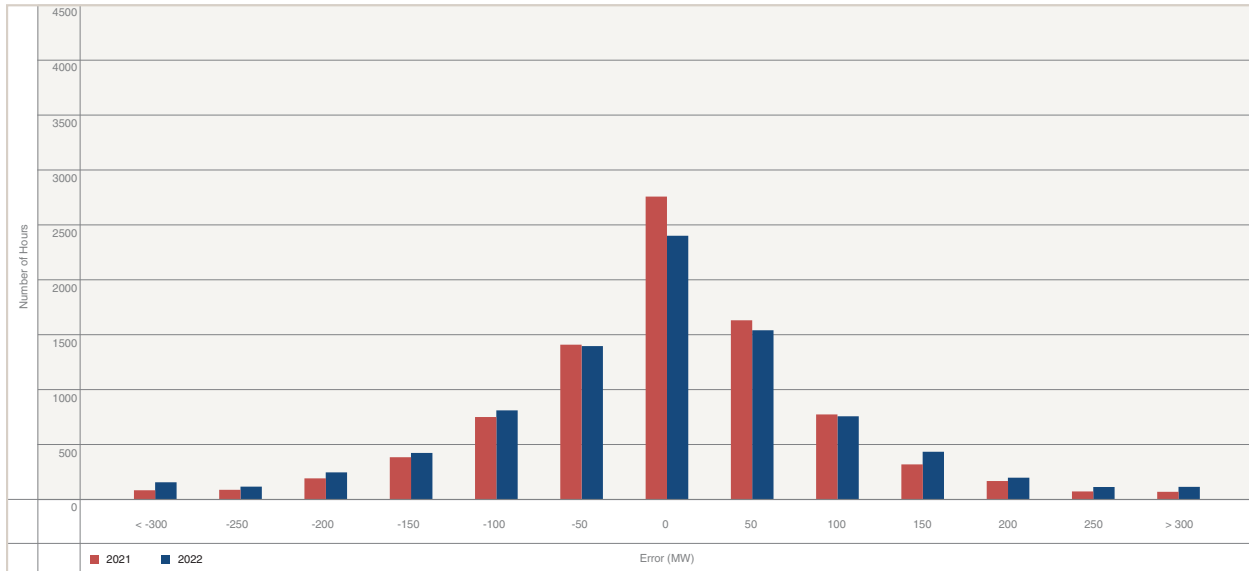
Wind power forecast uncertainty

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. AESO System Controllers require accurate short-term wind power forecasts to manage net demand variability. Therefore, the error of the short-term forecast is used to measure the uncertainty of the wind and solar forecasts.

For a given hour, the wind power forecast error is calculated as the hour-ahead forecasted wind volume minus the actual wind generation. Figure 45 shows the distribution of the calculated errors for the wind power forecast in 2021 and 2022. Overall, the average forecast error increased to 79 MW from 68 MW in 2021. However, as a percentage of installed wind capacity, the error improved to 3.1 per cent from 3.5 per cent in 2021. The error for 2022 was impacted by some market participants overstating the capacity of new wind projects during the commissioning period. As a result, a higher capacity of generation at these projects was forecasted than was truly available. This was especially true in November and December, when over 800 MW of new wind projects connected to the grid. Absent this issue, the calculated error would likely have been lower

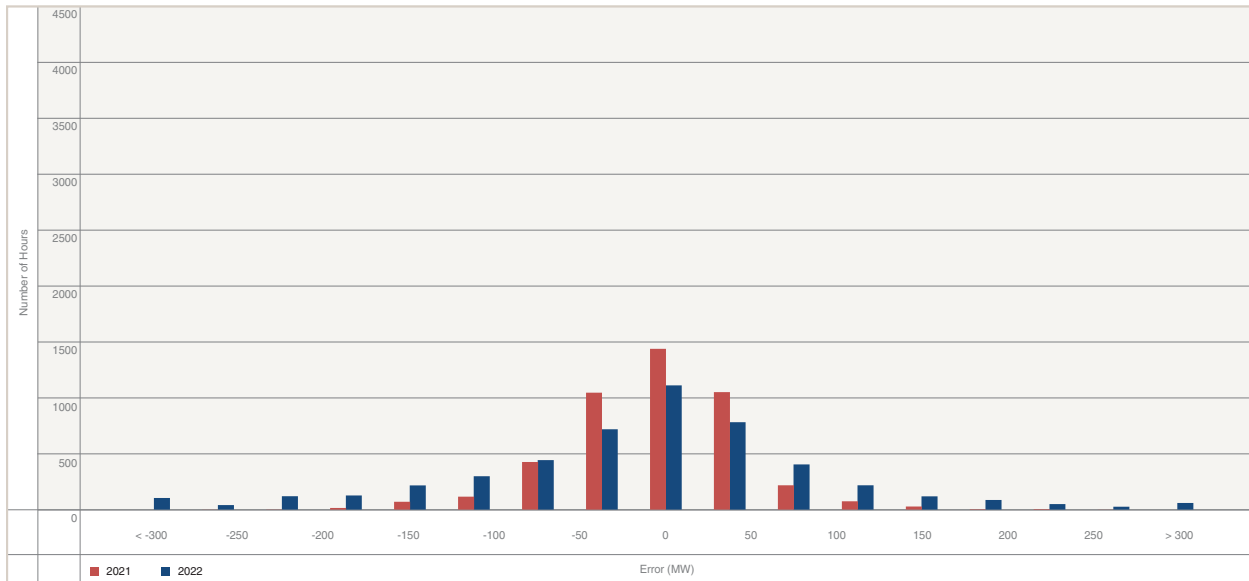
¹⁵ <https://www.aeso.ca/grid/forecasting/wind-and-solar-power-forecasting/>

FIGURE 45: Distribution of hour-ahead wind power forecast error in 2021 and 2022



Like the wind power forecast, the forecast error for solar power is calculated as the hour-ahead forecasted volume minus the actual volume. Figure 46 shows the distribution of the calculated errors for the solar forecast in 2021 and 2022. This data excludes any non-daylight hours, where the forecast and actual generation was zero. Overall, the average forecast error increased to 37 MW from 16 MW in 2021. As a percentage of installed solar power capacity, the error improved to 3.9 per cent from 5.3 per cent in 2021.

FIGURE 46: Distribution of hour-ahead solar forecast error in 2021 and 2022



Unit on/off cycling

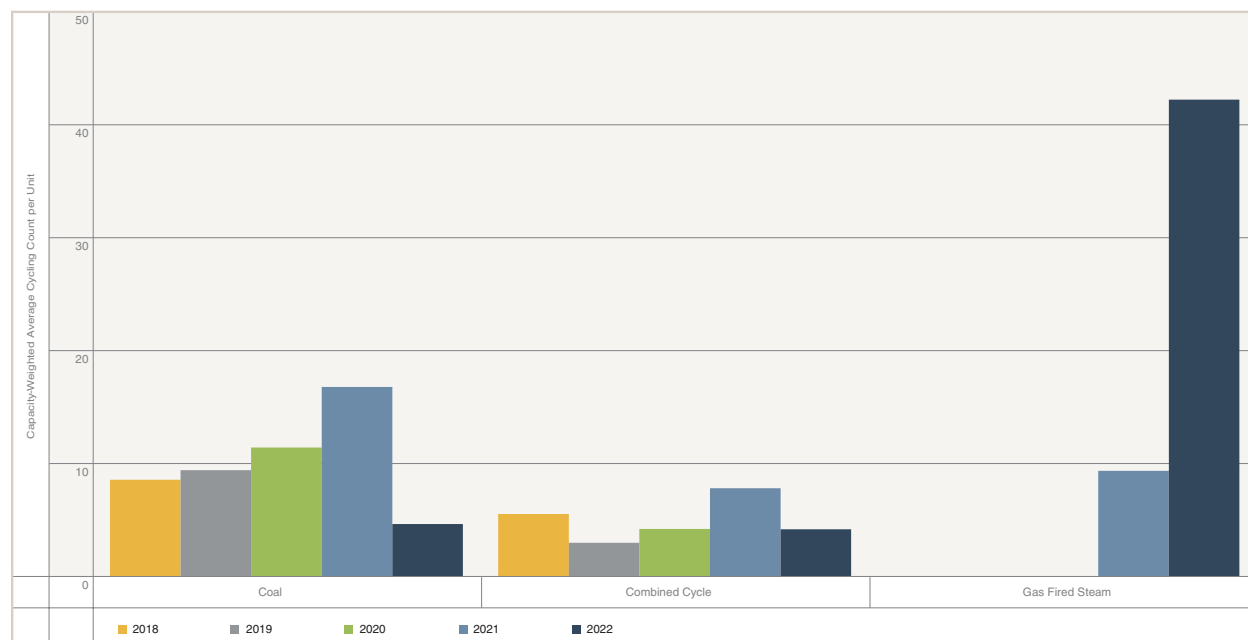
On/off cycling refers to starting up from a non-operational state, operating at any level for any duration, and then shutting down to return to a non-operational state. On/off cycling typically increases the operational costs for baseload generation, such as combined-cycle and coal-fired generating units 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. This section also contains former coal-fired generating units that have been converted to gas-fired steam generating units. The AESO will continue to monitor such units to identify whether there are changes to cycling behavior in the future.

The number of on/off cycles for each unit was first counted for each year from 2018 to 2022. 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 47 illustrates the average number of on/off cycles over the last five years. In 2022, most coal units have converted to other fuel types including gas-fired steam. The significant drop in coal combined with the significant increase in gas-fired steam is in part a reflection of that conversion. The capacity of generation using gas-fired steam technology more than doubled in 2022 compared to 2021. Furthermore, the increase in gas-fired steam cycling is due to the technology being on the margin the most in 2022, compared to other technology types.

FIGURE 47: 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 2023 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. In addition, there are multi-year forward-looking reports, such as the Long-Term Outlook and the Long-Term Adequacy reports. Finally, the AESO continues to explore additional reliability and flexibility 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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