aeso

AESO 2024 Annual Market Statistics

MARCH 2025

Executive Summary

The Alberta Electric System Operator (AESO) facilitates a fair, efficient and openly competitive (FEOC) electricity market and provides for the safe, reliable and economic operation of the Alberta Interconnected Electric System (AIES).

The *AESO 2024 Annual Market Statistics Report* offers a detailed summary of key market trends and data from the past year. The accompanying interactive data files provide further insights through dynamic dashboards and supporting information for all tables and figures within the report.

Price	**2023**	**2024**	**Year/Year Change**
Pool price	$133.63/MWh	$62.78/MWh	-53%
Gas price	$2.55/GJ	$1.30/GJ	-49%
Spark spread @ 7.5 GJ/MWh	$114.52/MWh	$53.07/MWh	-53.7%

Load	**2023**	**2024**	**Year/Year Change**
Average Alberta Internal Load (AIL)	9,851 MW	10,112 MW	+2.6%
Winter seasonal peak	12,384 MW	12,241 MW	-1.2%
Summer seasonal peak	11,522 MW	12,221 MW	+6.1%

Installed Capacity	**2023**	**2024**	**Year/Year Change**
Total	20,777 MW	23,122 MW	+11.3%
Gas	11,874 MW	14,136 MW	+19.1%
Wind	4,481 MW	5,688 MW	+26.9%
Solar	1,650 MW	1,812 MW	+9.8%

Supply Trends	**2023**	**2024**	**Year/Year Change**
Average Supply Cushion	1,574 MW	1,794 MW	+13.9%
Supply Surplus Hours	27	289	+970%

Intertie Flows (Imports = +)	**2023**	**2024**	**Year/Year Change**
British Columbia	-141 MW	-253 MW	-79%
Montana	75 MW	21 MW	-72%
Saskatchewan	66 MW	21 MW	-68%

During 2024, 384 participants transacted approximately $7.6 billion of energy in the Alberta wholesale electricity market.

Capacity Expansion and Energy Transition

Generation Capacity Additions

Alberta's total installed generation capacity grew by 11.3 per cent, ending 2024 at 23,122 megawatts (MW). Key contributions included 1,876 MW of new gas generation and 1,369 MW of wind and solar capacity introduced to the grid.

Transition Off Coal to Gas

The province completed its coal-to-gas transition with the last coal-fired generator converting to gas in June 2024, marking a significant milestone in Alberta's cleaner energy evolution.

Energy Prices Decreased

Lower Electricity and Natural Gas Prices

Average pool prices dropped significantly in 2024, falling 53 per cent to $62.78/megawatt hour (MWh) compared to 2023, while gas prices declined 49 per cent to $1.30/gigajoule (GJ). These price reductions occurred despite record-setting demand levels observed in 2024, primarily due to the rapid growth in Alberta's generation capacity.

Pricing Context for Stakeholders

The 2024 average pool price was below the 10-year average, offering a more cost-effective environment for consumers and industries reliant on electricity.

Demand Growth and Peak Records

Demand Growth Trends

Alberta's electricity demand reached record levels in 2024 due to several factors, including growth of oil sands demand, a rebound from 2023 wildfire impacts, and extreme temperatures in January and July. Compared to 2023, the average Alberta Internal Load (AIL) rose by 2.6 percent to 10,112 MW.

Record-Setting Peaks

New records were established for both winter and summer demand peaks. The winter peak was up 1.6 per cent to reach 12,384 MW (Winter 2023, set in January 2024), while the summer peak climbed 6.1 per cent to 12,221 MW.

Renewables Growth and System Challenges

Renewables Uptick Amidst System Variability

Renewables (wind, solar and hydro) contributed approximately 19 per cent of total electricity generation in 2024, up from 17 per cent in 2023. However, rapid wind and solar expansion heightened net demand variability (NDV), surpassing projected levels by two years.

System Stability Measures

The AESO introduced higher regulating reserve volumes and other grid stability measures to address the NDV in late 2023.

Changing Intertie Trend

Increased Export Volumes

Beginning in 2022, there has been a trend of lower import and higher export volumes. For the first time since 2016, Alberta became a net electricity exporter, as increased Alberta generation capacity and reduced hydroelectric reserves in neighbouring regions provided more export opportunities.

Market Policy and Regulatory Developments

Interim Market Power Mitigation Rules

At the direction of the government, the AESO implemented, in July 2024, the Supply Cushion Directives (SCD) and Interim Secondary Offer Cap (SOC) regulations. These measures were designed to address affordability and market power concerns.

Operating Reserve Insights

Total operating reserve (OR) costs dropped 28 per cent to $271 million, primarily due to lower active OR prices caused by the fall in pool prices. Overall standby OR costs fell 64 per cent to $16 million, as standby pricing optimizations led to lower activation costs and offset an increase in standby procurement costs.

Contents

EXECUTIVE SUMMARY I

Capacity Expansion and Energy Transition ii

Generation Capacity Additions ii
Transition Off Coal to Gas ii

Energy Prices Decreased ii

Lower Electricity and Natural Gas Prices ii
Pricing Context for Stakeholders ii

Demand Growth and Peak Records ii

Demand Growth Trends ii
Record-Setting Peaks ii

Renewables Growth and System Challenges ii

Renewables Uptick Amidst System Variability ii
System Stability Measures ii

Changing Intertie Trend iii

Increased Export Volumes iii

Market Policy and Regulatory Developments iii

Interim Market Power Mitigation Rules iii

Operating Reserve Insights iii

ELECTRICITY PRICES 1

Pool Prices Dropped 53 Per Cent 1

TABLE 1: Annual Market Price Statistics 1
FIGURE 1: Monthly Average Pool Price 2
FIGURE 2: Frequency of High-Priced Hours 3
FIGURE 3: Frequency of Low-Priced Hours 4
FIGURE 4: Pool Price Duration Curve 5

Historical Pool Price and Reserve Margin 5

FIGURE 5: Yearly Pool Price and Reserve Margin 6

ALBERTA LOAD 7

Average Load Grew 2.6 Per Cent 7

TABLE 2: Annual Load Statistics 7

Monthly Average AIL 8

FIGURE 6: Monthly Average AIL 9
FIGURE 7: Annual AIL Duration Curves 9

Seasonal Load 10

TABLE 3: Seasonal Peak Load 10

Regional Load 10

FIGURE 8: Regional Average Load 11

ALBERTA GENERATION 12

Generation Capacity Increased by 11.3 per cent 12

FIGURE 9: Year-End Gross Generation Capacity by Technology 12
FIGURE 10: Quarterly Capacity Additions and Retirements by Technology 13
TABLE 4: 2023-2024 Thermal Generation Retirements, Additions and Conversions 13
FIGURE 11: Monthly Generation from Major Retiring or New Thermal Assets 14

Gas Generation Supplied 75 per cent of all Electricity 15

FIGURE 12: Annual Average Overall Generation by Technology 15
FIGURE 13: Share of Total Generation by Technology 16

Monthly Average Overall Generation 16

FIGURE 14: Average Generation by Technology by Month (2024) 17

Hourly Average Generation 17

FIGURE 15: Average Generation by Technology by Hour (2024) 17

Availability Factors and Long-Lead-Time Assets 18

FIGURE 16: Annual Net-to-Grid Availability Factor by Technology 18

Capacity Factor 19

FIGURE 17: Annual Gross Capacity Factor by Technology 19

Achieved Prices Drop for Most Fuel Types in 2024 20

FIGURE 18: Annual Achieved Price by Technology 20
FIGURE 19: Annual Achieved Premium-to-Pool Price 21

Marginal Price-Setting Technologies 22

FIGURE 20: Annual Marginal Price-Setting Technology 22

Wind Generation 22

Table 5 summarizes annual wind generation statistics over the last five years, showing significant growth. 22

TABLE 5: Annual Wind Generation Statistics 22
FIGURE 21: Monthly Average Wind Capacity and Generation 23

FIGURE 22: Annual Wind Capacity Factor Duration Curves 24
FIGURE 23: 2024 Wind Generation Seasonal Average Hourly Output 25
Regional Wind **25**
TABLE 6: 2024 Regional Wind Statistics 25
FIGURE 24: Monthly Wind Capacity Factor by Region 26
Solar Generation **26**
TABLE 7: Annual Solar Generation Statistics 27
FIGURE 25: Monthly Average On-Peak Solar Capacity and Generation 27
FIGURE 26: 2024 Seasonal Average Hourly Output of Solar Fleet 28
Interim Market Power Mitigation Rules **28**
Secondary Offer Price Cap **28**
Supply Cushion Directives **28**
IMPORTS AND EXPORTS **29**
Import ATC up 70 MW due to Increased FFR Volumes **29**
FIGURE 27: Average Annual Path Rating by Transfer Path 29
Alberta a Net-Exporter in 2024 **30**
FIGURE 28: Annual Availability Utilization by Transfer Path 30
FIGURE 29: Annual Interchange Utilization with WECC Region 31
FIGURE 30: Annual Interchange Utilization with Saskatchewan 32
FIGURE 31: Annual Intertie Transfers by Province or State 33
FIGURE 32: Monthly Average Intertie Transfers 34
Net-Exports More Common in Low-Priced Hours **35**
FIGURE 33: Annual Achieved Premium-to-Pool Price on Imported Energy 35
FIGURE 34: Yearly Count of Hours by Price and Net Import/Export Status 36
SUPPLY ADEQUACY **37**
Generation Outages Higher due to Commissioning **37**
FIGURE 35: Annual Hourly Average Generation Outages by Fuel Type 37
FIGURE 36: Generation Outages by Month 38
Average Supply Cushion Increased 14 per cent **38**
TABLE 8: Supply Cushion Summary by Year 38
FIGURE 37: Monthly Supply Cushion 39
Reserve Margin Increased 10 Per Cent **40**
FIGURE 38: Annual Reserve Margin 40
Eight Grid Alerts Issued in 2024 **40**
TABLE 9: 2024 Grid Alerts 41
Supply Surplus Events were called 76 times in 2024 **42**
FIGURE 39: Monthly Total Duration of Supply Surplus Events 42
FLEXIBILITY **43**
Intermittent Generation-to-AIL Ratio **43**
FIGURE 40: Ratio of Intermittent Generation to AIL 44
Net Demand Variability **44**
FIGURE 41: Distribution of 10-Minute Ramps for Wind and Solar Generation, Load, and Net Demand in 2024 45
FIGURE 42: Distribution of 2024 Year-Over-Year Change in 10-Minute Ramps for Wind and Solar Generation, Load, and Net Demand 46
Forecast Uncertainty **46**
FIGURE 43: Distribution of Day Ahead Load Forecast in 2024 and 2023 47
FIGURE 44: Distribution of Hour-Ahead Wind Power Forecast Error in 2024 and 2023 48
Solar Power Forecast Uncertainty **49**
FIGURE 45: Distribution of Hour-Ahead Solar Forecast Error in 2024 and 2023 49
Unit On/Off Cycling **50**
FIGURE 46: Average Number of On/Off Cycles Per Generating Unit, by Technology and Year 50
ANCILLARY SERVICES **51**
Cost of Operating Reserves Decreased **51**
TABLE 10: Annual Operating Reserve Statistics 51
FIGURE 47: 2024 Market Share of Active Operating Reserve 52
FIGURE 48: 2024 Market Share of Standby Operating Reserve 53
Transmission Must-Run, Transmission Constraint Rebalancing, and Dispatch Down Service **53**
TABLE 11: Annual TMR and DDS Statistics 54
FIGURE 49: Monthly TMR and DDS Dispatched Energy 55
Payments to Suppliers on the Margin **55**
TABLE 12: Annual Uplift Payments 55
GLOSSARY **56**

Electricity Prices

Pool Prices Dropped 53 Per Cent

Driven by an increase in low-cost generation from new efficient gas-fired baseload capacity and additional output from recently built wind and solar assets, the 2024 daily average pool price ($62.78) dropped by 53 per cent from 2023 ($133.63), despite higher overall demand.

Specifically, lower gas prices accounted for about $9 with the rest mainly driven by increased competition from new generation.

Table 1 summarizes historical pool price statistics over the 10-year period between 2015 and 2024, along with other price-related metrics.

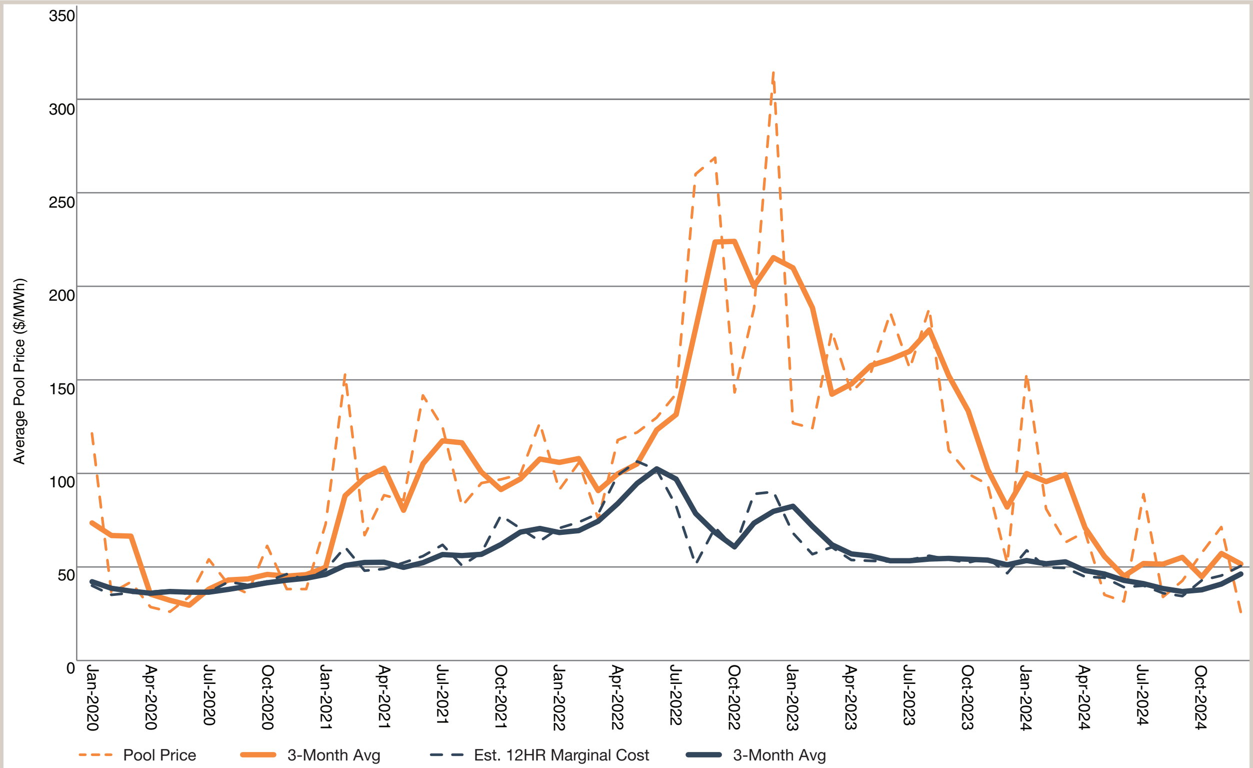
TABLE 1: Annual Market Price Statistics

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Pool price ($/MWh)										
Daily Average	33.34	18.28	22.19	50.35	54.88	46.72	101.93	162.46	133.63	62.78
On-peak average	40.73	19.73	24.46	59.28	64.12	54.72	122.61	192.13	156.15	74.46
Off-peak average	18.55	15.37	17.64	32.47	36.40	30.71	60.58	103.14	88.59	39.43
Spark Spread at 7.5 GJ/MWh ($/MWh)										
Daily Average	14.12	2.77	6.70	39.54	42.21	30.81	76.39	124.46	114.52	53.06
Estimated Gas Unit Marginal Cost ($/MWh)[1]										
High Efficiency (7HR)	23.27	19.82	19.91	15.77	17.51	20.53	29.75	41.60	24.31	15.89
Low Efficiency (12HR)	40.29	34.37	35.84	31.39	34.37	39.55	58.00	80.96	55.29	44.82
Estimated Carbon Cost ($/MWh)										
High Efficiency 7HR)	0.63	0.79	1.41	-0.53	-0.53	-0.53	-0.71	-0.89	-0.67	-0.24
Low Efficiency 12HR)	1.09	1.36	2.42	7.02	7.02	7.02	9.35	11.69	15.68	19.89
Gas Price ($/GJ)										
Daily Average	2.56	2.07	2.06	1.44	1.69	2.12	3.41	5.07	2.55	1.30

[1] The estimated gas unit marginal costs include the fuel cost (HR times gas price), the estimated carbon cost and an assumed $5 MW/h for operating and maintenance. The gas price is the day-ahead AECO spot price.

Figure 1 compares the monthly average pool price over five years to the estimated marginal cost of a theoretical low-efficiency simple-cycle natural gas unit. This marginal cost is for a 12-gigajoule (GJ) per megawatt-hour (MWh) unit, including $5 for operation and maintenance costs as well as the estimated carbon costs.

FIGURE 1: Monthly Average Pool Price



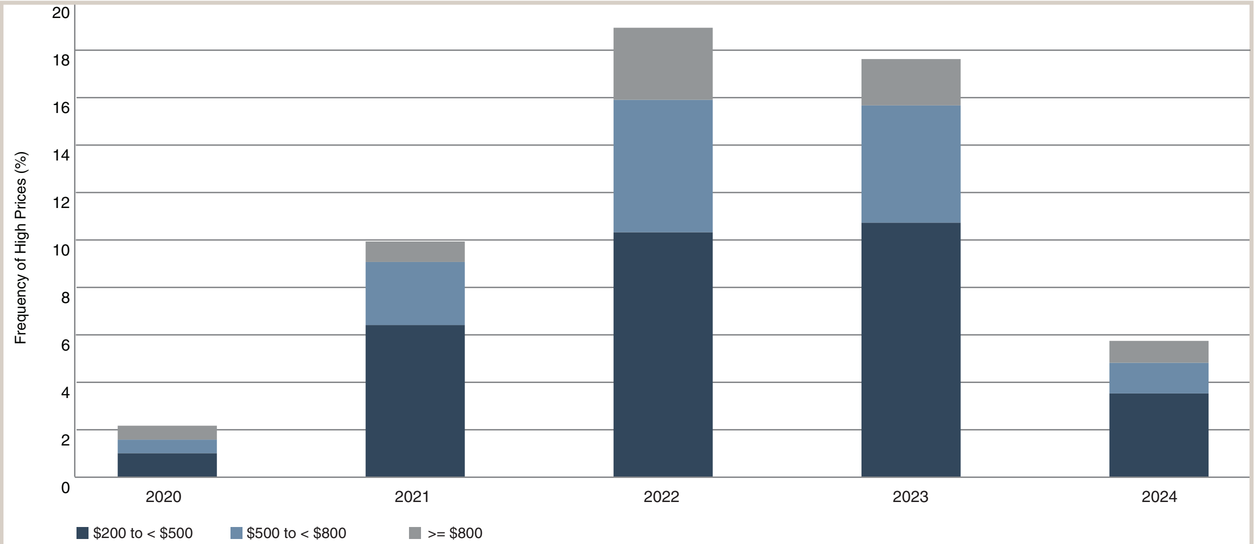
Key Observations:

- In 2020, a sharp drop in demand due to COVID-19 restrictions created a small spread of $6 between the pool price and the estimated marginal cost of running a gas unit.
- In 2021, with the expiration of Power Purchase Agreements (PPA), many units' offer control returned to the original owners from the Balancing Pool. This led to higher energy market prices and increased the spread to about $44.
- From Q3 2020 and Q2 2022, the retirement of 1,300 MW of coal generation led to reduced supply and a significant rise in pool prices. As a result, the pool price to gas unit marginal cost spread averaged $81 in 2022 and $78 in 2023.
- Pool prices hit a peak between Q2 2022 and Q2 2023 but trended down later in 2023 as new wind and solar projects came online, and H.R. Milner's 300-MW gas unit returned after a year-long outage due to a fire.
- The 900-megawatt (MW) Cascade Power Plant began operating in January 2024 and was fully commissioned by June, helping lower pool prices and shrinking the gas unit spread from $30 in Q4 2023 to $12 by Q3/Q4 2024.
- Additionally, Suncor's new cogeneration asset began commissioning in October 2024.

Figure 2 shows how often electricity prices exceeded $200 per hour over the last five years.

Alberta's hourly electricity price is based on 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. These offers are ranked from lowest to highest to form the energy market merit order.

FIGURE 2: Frequency of High-Priced Hours

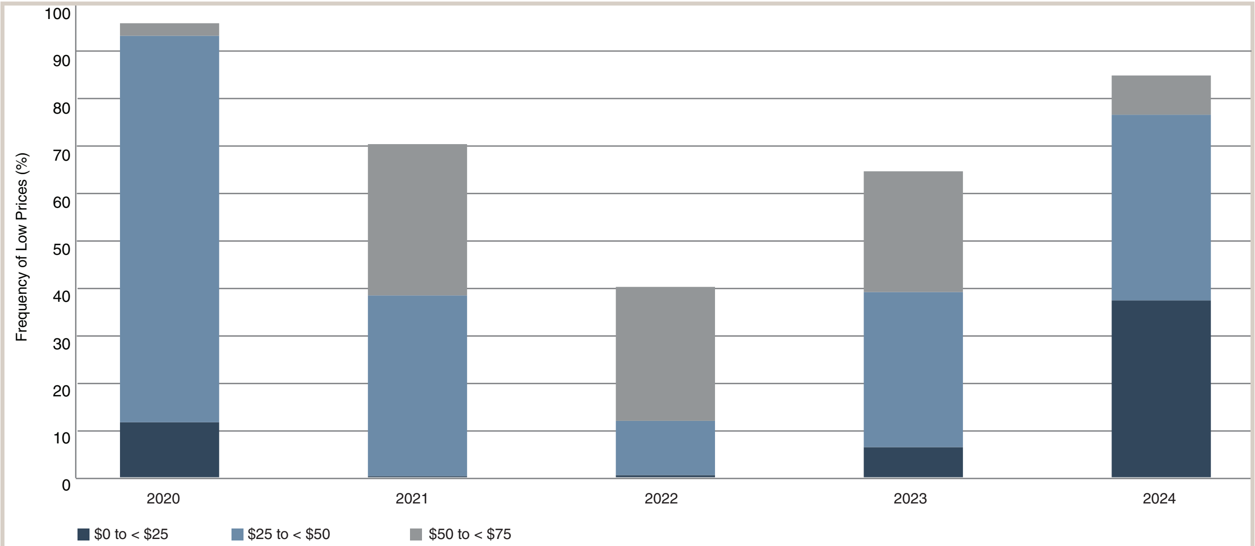


Key Observations:

- The expiry of PPAs in 2021 led to higher offer and, thus, settled prices.
- High-priced hours doubled in 2022 and 2023 due to higher demand, lower supply, and high offer prices from some participants.
- By late 2023, high-priced hours dropped as new wind and solar projects added competition, alongside the return of a major thermal unit.
- In 2024, additional baseload thermal generation and increased generation from wind and solar cut the number of high-priced hours by nearly two-thirds.

Figure 3 shows how often electricity prices fell below $75 per hour over the last five years, with a focus on sub-$25 hours.

FIGURE 3: Frequency of Low-Priced Hours

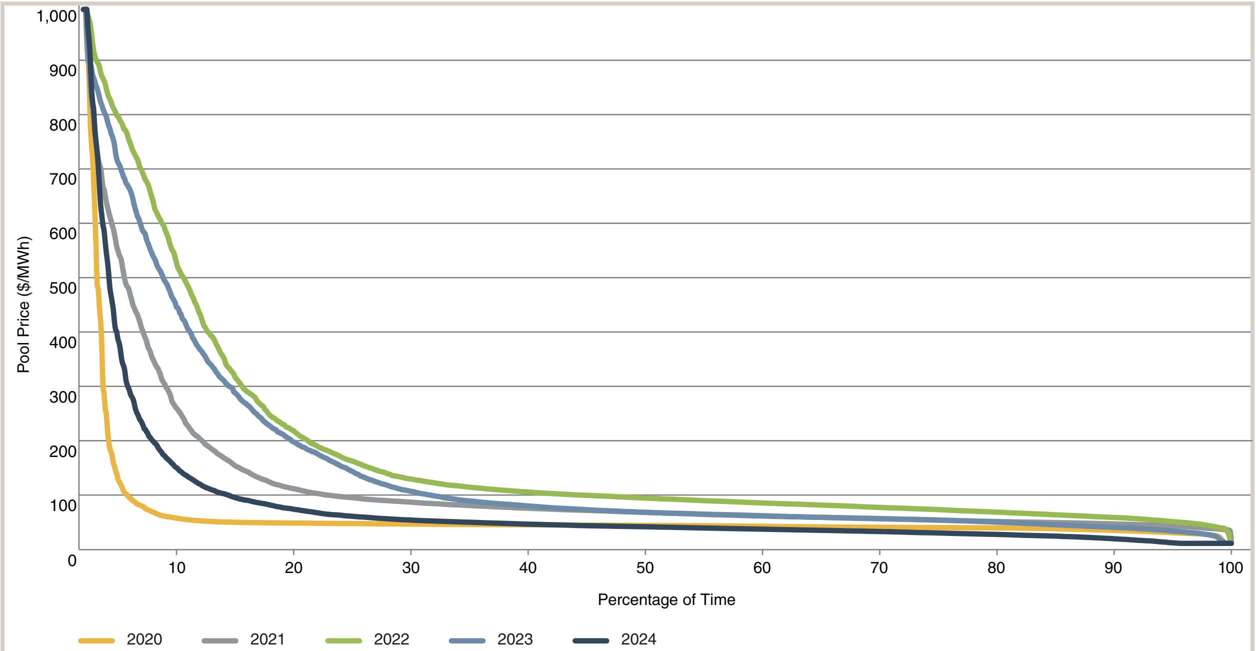


Key Observations:

- Low demand from COVID restrictions caused a spike in low-priced hours in 2020.
- High gas prices and low supply left almost no sub-$25 hours in 2021 and 2022.
- By 2023, lower gas prices and more wind and solar generation slightly increased sub-$25 hours. Wind and solar, typically priced at $0, lowered pool prices when available.
- In 2024, new baseload thermal generation, with marginal costs around $15-20, significantly boosted sub-$25 hours.

Figure 4 shows the price duration curve for how often hourly pool prices occurred over the previous five years. The data shows 2024 resembled 2020 in the number of hours with prices below $50.

FIGURE 4: Pool Price Duration Curve



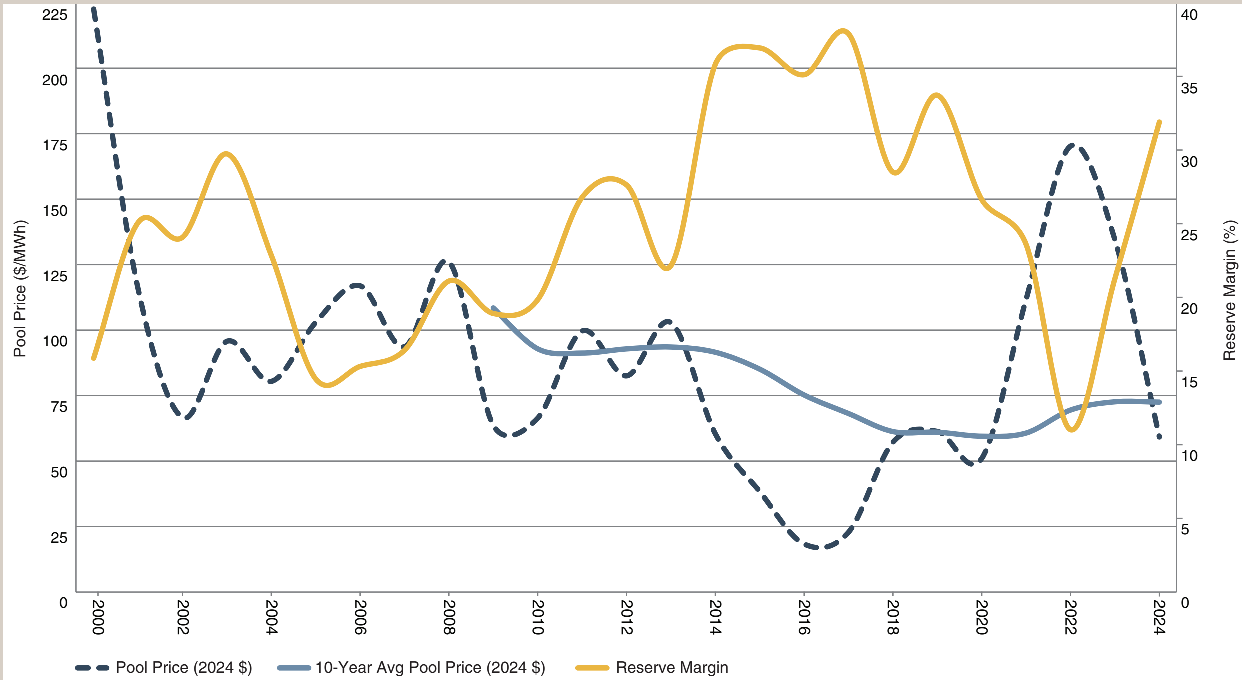
Historical Pool Price and Reserve Margin

Over the past decade, the Alberta electricity market has experienced notable fluctuations in pool prices, shaped significantly by shifts in supply, demand, and external factors.

Figure 5 highlights these trends with inflation-adjusted yearly pool prices (in 2024 dollars), the 10-year rolling average, and AESO's annual reserve margin.

- Between 2015 and 2024, the inflation-adjusted 10-year pool price average stood at $75, significantly lower than the $111 average recorded during 2000–2009.
- Included in the 10-year average pool price ending in 2024 are three of the five highest nominal pool prices in AESO's history (2021 to 2023).

FIGURE 5: Yearly Pool Price and Reserve Margin



Key Observations:

- High reserve margins, driven by a surge in new thermal generation and reduced demand from declining oil prices, created an environment of sustained low electricity prices from 2014-2020.
- The retirement of coal-fired units, coupled with rising demand, led to falling reserve margins and significant price spikes in 2021.
- In 2022, impacts from supply chain disruptions from the COVID-19 pandemic delayed planned generation projects and exacerbated supply and demand imbalances and led to a record-low reserve margin, as well as higher price volatility.
- Additional wind, solar, and thermal capacity, combined with lower demand pressure in 2023, returned stability to the market.
- Prices in 2024 fell below the 10-year average despite record-high demand due to addition of delayed natural gas generation and increased intermittent generation.

These observations highlight the Alberta market's sensitivity to demand fluctuations, supply economics and external factors. High prices tend to drive investments in new generation, while low prices prompt generator retirements, underscoring the cyclical nature of supply and demand.

Alberta Load

All annual load statistics in this report are based on the calendar year from January 1 to December 31. Seasonal load statistics are based on the following periods:

- Winter: November 1 to April 30
- Summer: May 1 to October 31

References to winter and summer use these seasonal definitions.

Average Load Grew 2.6 Per Cent

Table 2 summarizes the annual demand statistics over the past 10 years.

TABLE 2: Annual Load Statistics

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Alberta Internal Load										
Total (GWh)	80,257	79,560	82,572	85,330	84,925	83,115	85,214	86,572	86,293	88,827
Average (MW)	9,162	9,055	9,426	9,741	9,695	9,460	9,728	9,883	9,851	10,112
Maximum (MW)	11,229	11,458	11,473	11,697	11,471	11,698	11,729	12,193	11,572	12,384
Minimum (MW)	7,203	6,595	7,600	7,819	8,024	7,579	7,976	8,110	7,873	8,166
Average change	0.4%	-1.1%	4.1%	3.3%	-0.5%	-2.4%	2.8%	1.6%	-0.3%	2.6%
Load factor	81.6%	79%	82.2%	83.3%	84.5%	80.9%	82.9%	81.1%	85.1%	81.7%
System Load										
Total (GWh)	61,299	60,773	62,393	62,942	61,626	60,201	60,985	61,873	60,929	63,054
Average (MW)	6,998	6,919	7,123	7,185	7,035	6,854	6,962	7,063	6,955	7,178
Average Change	-0.4%	-1.1%	2.9%	0.9%	-2.1%	-2.6%	1.6%	1.5%	-1.5%	3.2%
System Load-to-AIL Ratio	76.4%	76.4%	75.6%	73.8%	72.6%	72.4%	71.6%	71.5%	70.6%	71%
Implied BTF Load (MW)	2,164	2,139	2,304	2,556	2,660	2,609	2,766	2,819	2,895	2,934

Key Observations:

- In 2024, average Alberta Internal Load (AIL) grew by 2.6 per cent, driven by increased oil industry demand, higher load during extreme temperatures, and the recovery of load lost to wildfire impacts.
- Adjusting for year-over-year temperature differences, most of the growth was structural rather than weather-related.
- A decrease in the AIL load factor shows that high load periods in 2024 were more extreme than in 2023.
- Total AIL rose by 2.9 per cent and average AIL by 2.6 per cent. The higher total AIL growth is due to the leap day in 2024.
- Average system load increased 3.2 per cent, reflecting faster growth in bulk transmission system usage compared to overall load, driven by urban and industrial growth not self-supplied.
- In addition to this growth on the bulk transmission system, behind-the-fence (BTF) load grew 1.3 per cent.

Monthly Average AIL

Figure 6 shows the monthly average AIL over the last five years. Typically, large year-over-year differences in AIL are primarily due to temperature variations between the years.

- **2024:**
  - The Northeast region experienced steady growth due to increased activity at multiple oil sands sites.
  - There was significant load growth observed in January and July caused by extreme cold and heat. These high-load periods were likely a result of population growth, as similar profiles were observed in Calgary and Edmonton, but were not observed in other regions.
  - The AESO does not have access to the output of small generators, such as rooftop solar. However, the capacity of these assets was over 300 MW at the end of 2024 and it is believed their output is masking population growth-related load outside of periods of extreme temperatures.
- **2023:**
  - Wildfires led to load reductions of 100–150 MW in the Northwest and Central regions during May and June, with smaller impacts through the summer and early fall.
- **2020:**
  - COVID-19 restrictions caused noticeable load decreases between May and September.

FIGURE 6: Monthly Average AIL

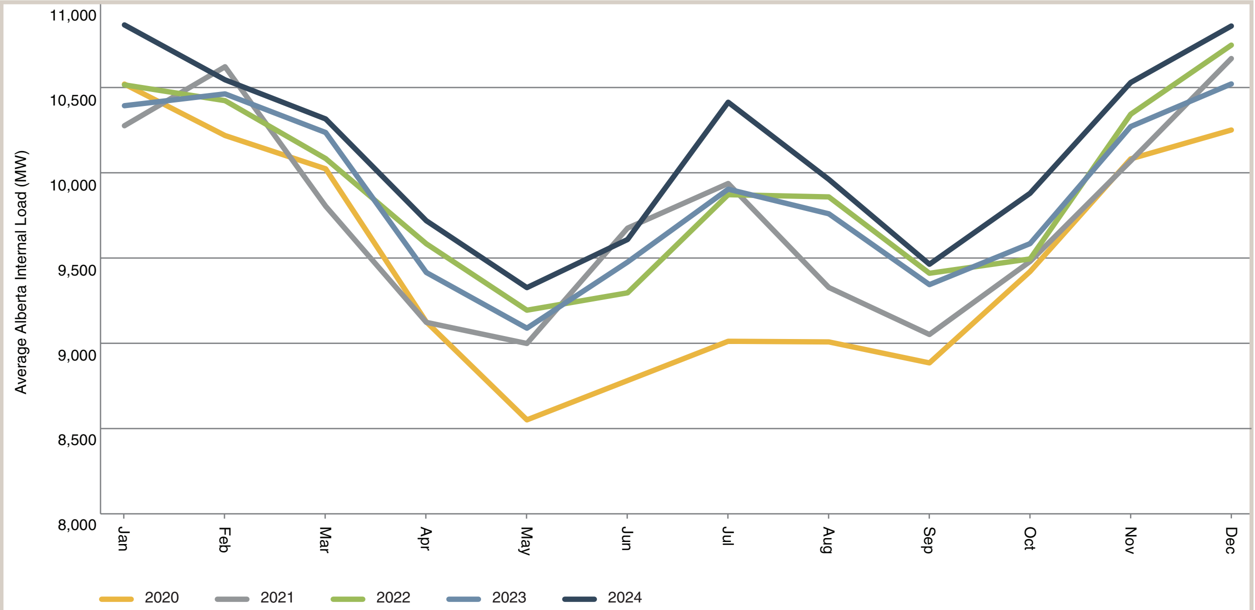
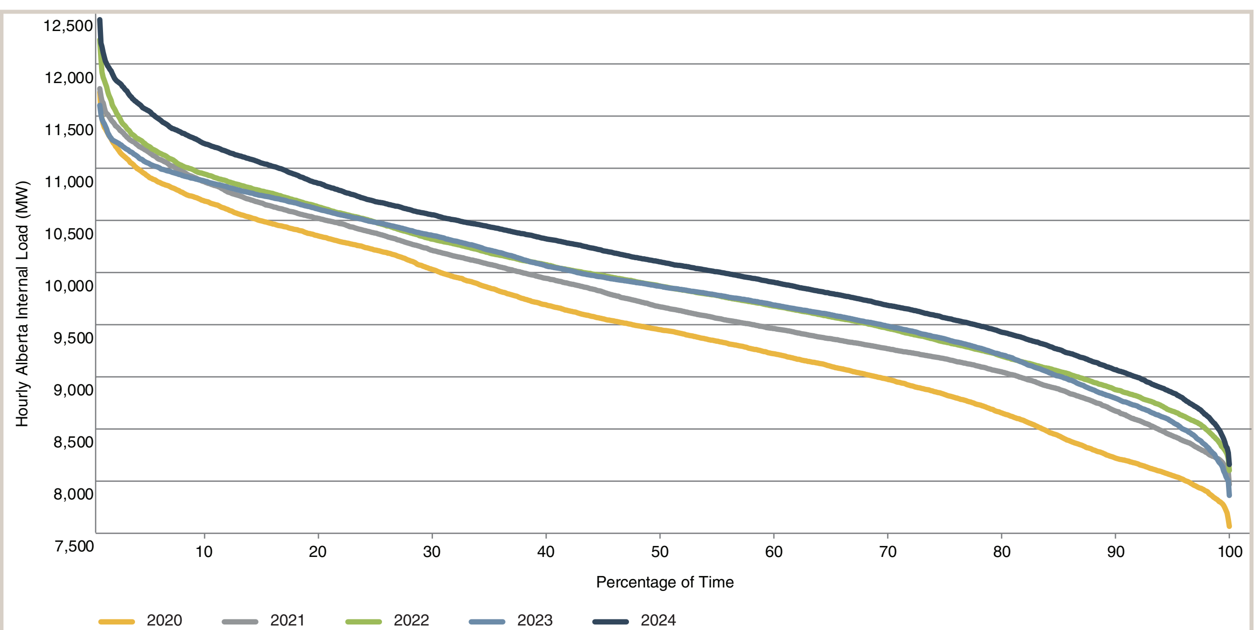


Figure 7 plots the annual load duration curve over the last five years.

The load duration curve shows the percentage of time AIL met or exceeded a specific volume.

- **2024:** Load growth can be seen across all hours.
- **2022 to 2023:** Minimal changes occurred, except for the highest and lowest 15 per cent of hours, driven by more extreme temperatures occurring in 2022.
- **2020:** The very low volumes reflect the impacts of the COVID-19 pandemic.

FIGURE 7: Annual AIL Duration Curves



Seasonal Load

Seasonal peaks in Alberta load typically align with periods of extreme temperatures: summer peaks are driven by heat and winter peaks by cold.

- July 22, 2024: A new summer peak electricity demand record was set, 4.3 per cent higher than the previous record from 2021. Calgary and Edmonton experienced temperatures at least seven degrees above normal, the highest in nearly 20 years.
- January 11, 2024: A new winter and overall AIL peak occurred.

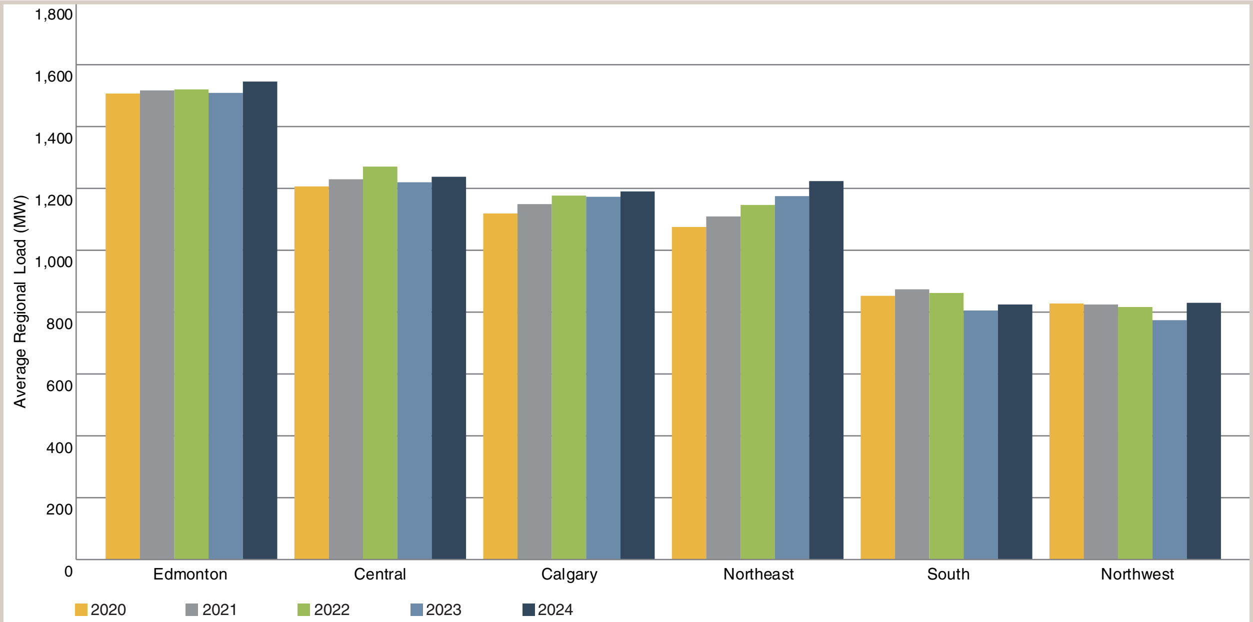
TABLE 3: Seasonal Peak Load

Season	PEAK AIL (MW)	Date	Calendar Year
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	12,193	2022-12-21	2022
Summer 2023	11,522	2023-07-24	2023
Winter 2023	12,384	2024-01-11	2024
Summer 2024	12,221	2024-07-22	2024
Winter 2024 (thru Jan 2025)	12,241	2024-12-18	2024

Regional Load

Figure 8 shows the average regional system load (excluding losses and BTF load) over the last five years. Overall AIL increased in 2024, but regional growth rates varied from year-to-year.

FIGURE 8: Regional Average Load



Key Observations:

- **Northeast:**
  - Load increased by 4.2 per cent, setting monthly records, primarily due to non-BTF load growth at multiple oil sands sites.
- **Edmonton and Calgary:**
  - Load increased by 2.4 per cent in Edmonton and 1.5 per cent in Calgary.
  - Most months saw average to above-average demand without reaching new highs, except in mid-January and mid-July when extreme temperatures led to new load records.
  - Population growth has been partly offset by increasing rooftop solar installation; however, extreme weather drove higher demand then has been seen in previous years.
  - Summer load growth was higher than winter load, likely due to increased air conditioner usage.
- **Central:**
  - Load increased by 1.5 per cent, primarily due to a rebound in demand following the reduction caused by wildfires in May and June 2023.
  - Otherwise, regional demand was comparable year-over-year, outside of some weather-related periods.
  - Peak annual demand in the central region occurred in 2018.
- **South:**
  - Load increased by 2.4 per cent, with most months averaging above-average demand.
  - High-demand spikes also occurred during extreme weather periods, but the region's peak demand year is still 2018.
- **Northwest:**
  - Load increased by 7.2 per cent, driven by recovery from wildfire-related weak demand in 2023 and low pool prices in late 2024, which incentivized demand to return.
  - The highest demand year for the region remains 2018.

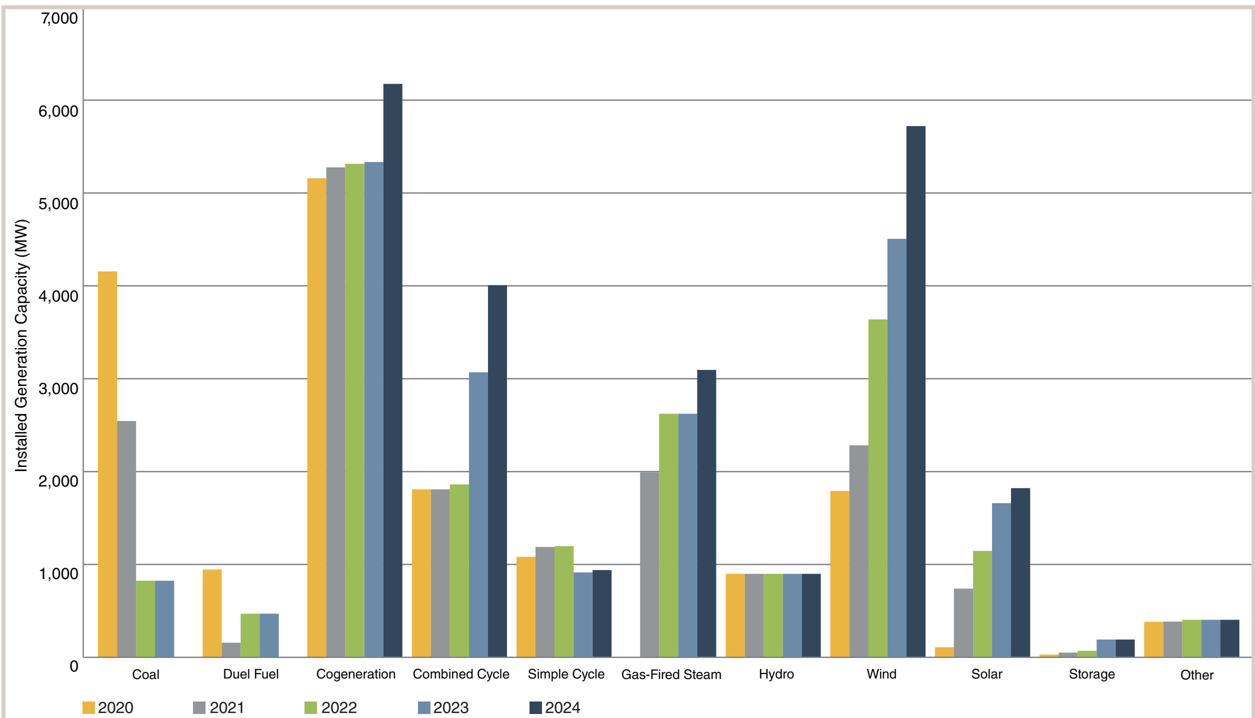
Alberta Generation

By the end of 2024, there were 222 assets with capacity greater than five MW supplying energy to Alberta's grid, spanning various fuel types including thermal assets, hydro, and inverter-based resources (IBRs).

Generation Capacity Increased by 11.3 per cent

Installed generation capacity increased by 2,345 MW to 23,122 MW by year-end 2024. Figure 9 shows the installed capacity of each fuel type at year-end for the last five years.

FIGURE 9: Year-End Gross Generation Capacity by Technology



Key Observations:

- By July 2024, all remaining coal and dual-fuel generation (1,286 MW) in Alberta was converted to natural gas.
- 976 MW of new capacity came from new gas-fired generation.
- 1,369 MW of new capacity came from new generation from wind and solar.[2]

[2] See Wind and Solar sections for details.

Figure 10 shows quarterly capacity additions and retirements over the past five years, highlighting the transition from coal to natural gas and the growth in renewable generation types.

FIGURE 10: Quarterly Capacity Additions and Retirements by Technology

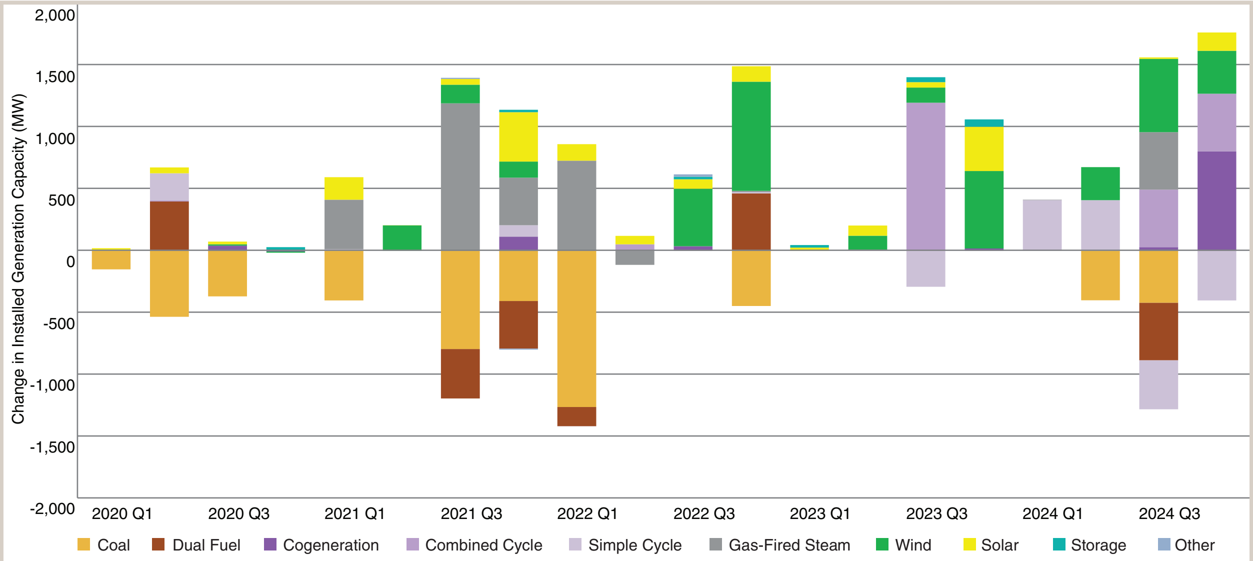


Table 4 provides details into major thermal retirements, conversions and additions in 2024.[3]

TABLE 4: 2023-2024 Thermal Generation Retirements, Additions and Conversions

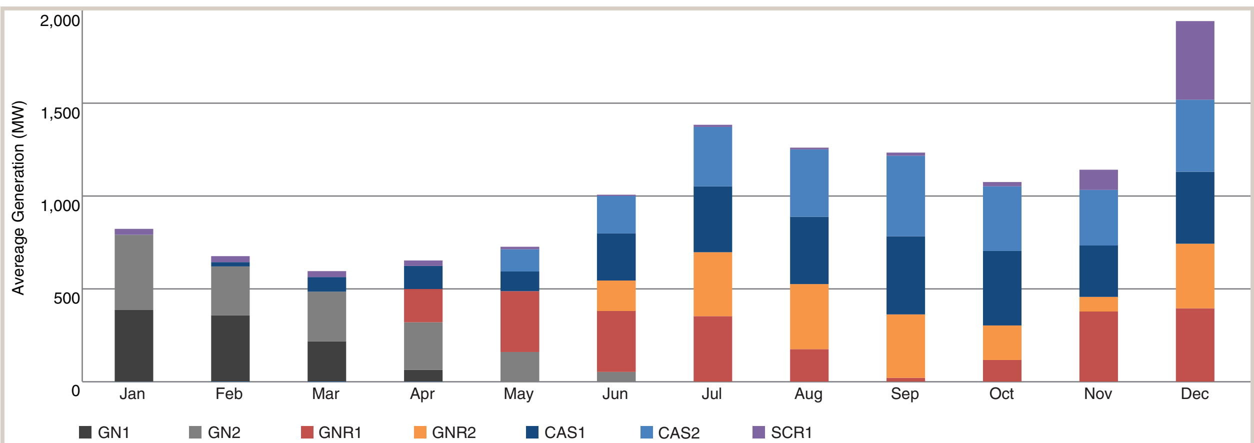
Key Events	
Q3 2023	■ Cascade 1 and 2 combined cycle assets connected to the grid (+900 MW combined) ■ H.R. Milner conversion from simple cycle to combined cycle completed (300 MW converted, no net capacity change)
Q1 2024	■ Cascade 1 started commissioning in Q1 2024 ■ Simple cycle component of Genessee Repower 1 connected (+411 MW)
Q2 2024	■ Cascade 2 started commissioning in Q2 2024 – Both Cascade units went into full service at the end of Q2 2024 ■ Genessee Repower 1 started supplying power in Q2 2024, replacing generation from Genessee 1 coal-fired unit (-400 MW) ■ Genessee 1 coal-fired generator officially retired ■ Simple cycle component of Genessee Repower 2 added (+411 MW) – Genesee Repower 2 started supplying power in Q2 2024, replacing generation from Genessee 2 coal-fired unit (-420 MW)

[3] From the AESO's perspective, a unit's capacity is considered installed when its transmission connection becomes active. There may be a significant delay between when an asset is installed to the grid and when it first begins supplying power to the grid. During the commissioning phase, assets may operate with derated capacity and experience frequent outages for a few months before reaching normal operations.

Key Events	
Q3 2024	■ Genessee 2 coal-fired generator officially retired ■ Genessee 3 dual-fuel generator converted to gas-fired steam (466 MW converted, no net capacity change) ■ Genessee Repower 1 converted from 411 MW simple cycle to 466 MW combined cycle (+55 MW)
Q4 2024	■ Genessee Repower 2 converted from 411 MW simple cycle to 466 MW combined cycle (+55 MW) ■ Suncor Base Plant cogeneration increased capacity from 50 MW to 856 MW (+806 MW)

Figure 11 shows the monthly output from the major retiring or newly added thermal assets in 2024.

FIGURE 11: Monthly Generation from Major Retiring or New Thermal Assets



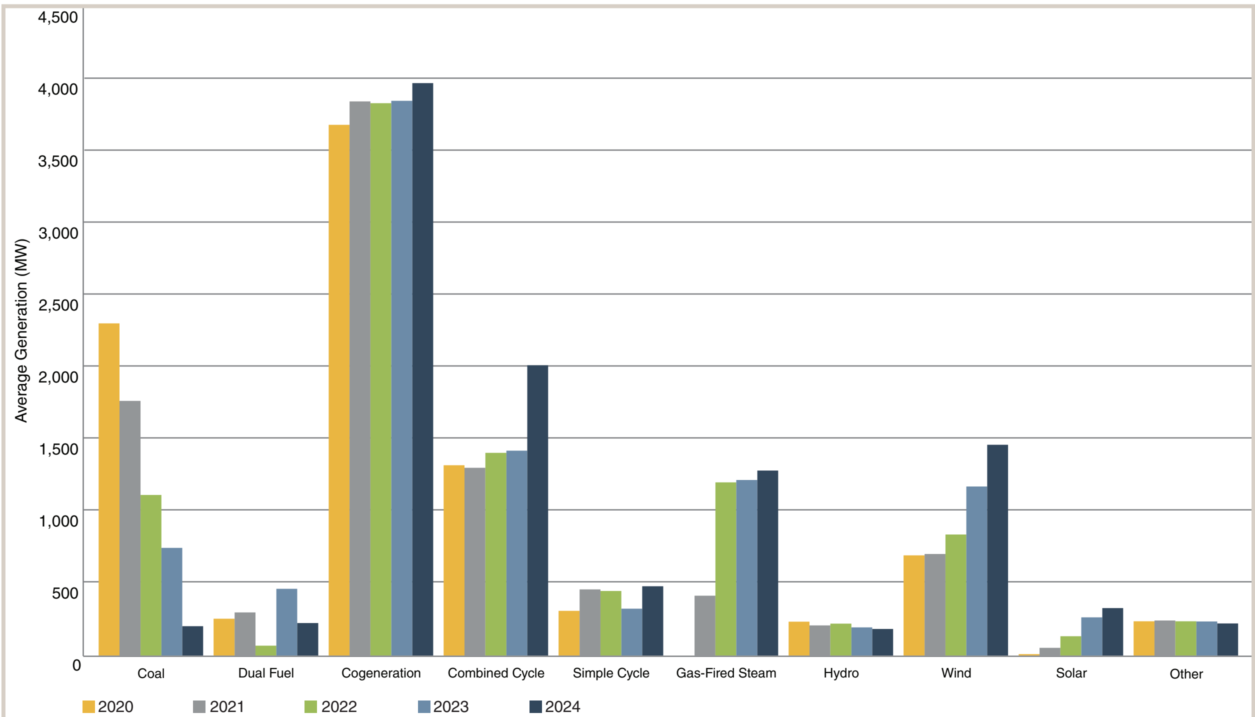
Key Observations:

- Gas-fired Genessee Repower units (GNR1 and GNR2) began replacing the output from coal-fired Genesee units (GN1 and GN2) in April 2024.
- Cascade units (CAS1 and CAS2) started generating in Q1 2024 but did not reach full, stable output levels until Q3.
- GNR1's output dropped between August and October, and GNR2's output decreased in October to November due to outages related to their conversion from simple-cycle to combined-cycle.
- Suncor Base Plant's (SCR1) expanded capacity had limited output in November 2024 but increased in December.

Gas Generation Supplied 75 per cent of all Electricity

Figure 12 shows the average hourly generation by technology over the past five years.[4]

FIGURE 12: Annual Average Overall Generation by Technology

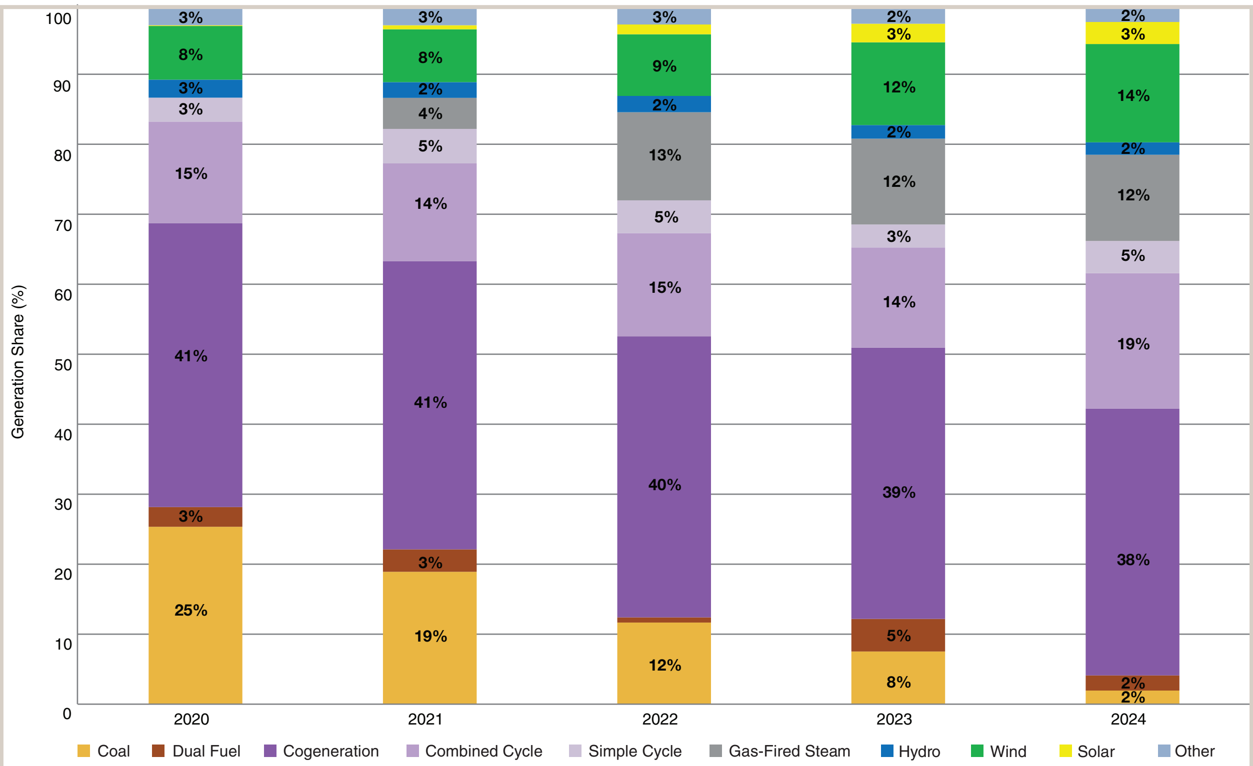


Key Observations:

- In 2024, gas-fired generation accounted for 74.7 per cent of Alberta's total generation, up from 68.9 per cent in 2023, as it fully replaced coal generation during the year.
- Wind, solar and hydro generation provided 19 per cent of Alberta's generation in 2024, up from 16.5 per cent in 2023.
  - Interim targets under *Alberta's Renewable Electricity Act* include a 20 per cent renewable generation target for 2025 and 30 per cent by 2030.

[4] Generation calculated from all assets with a capacity greater than five MW.

FIGURE 13: Share of Total Generation by Technology



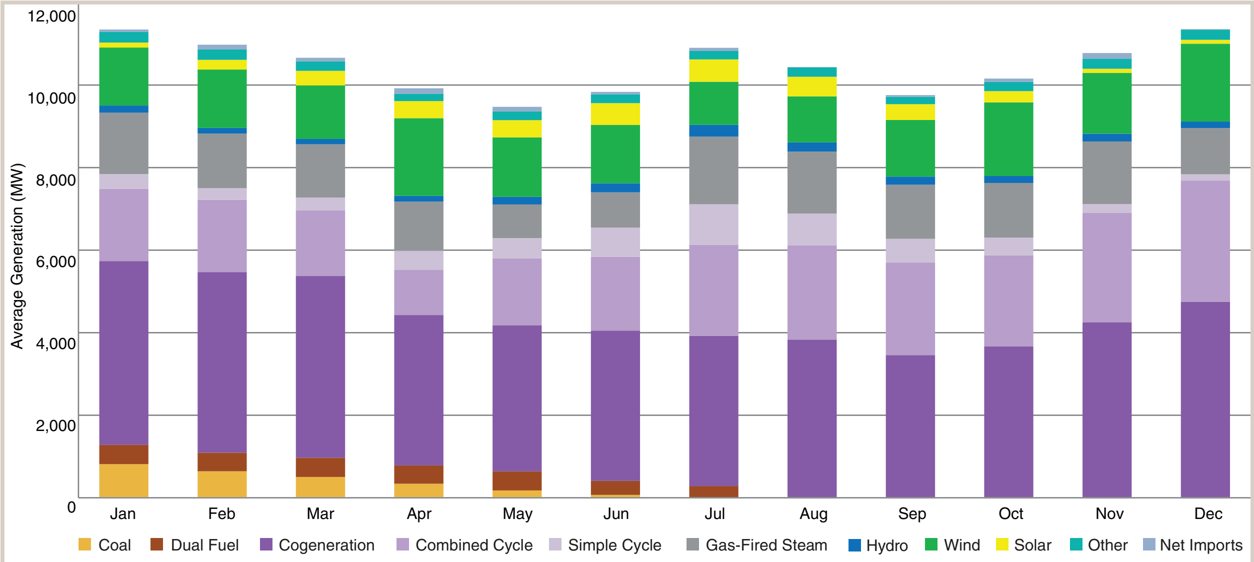
Monthly Average Overall Generation

Average generation varies by month, aligning with higher demand during the coldest and warmest months.

Figure 14 shows the monthly average generation and technology's share of the total in 2024.

- January and December recorded the highest average hourly generation, while May had the lowest.
- The phase-out of coal (and dual-fuel) generation is evident leading up to July 2024. The converted assets are reflected in increased combined cycle and gas-fired steam generation in the second half of the year.
- The expansion of Suncor Base Plant increased the monthly cogeneration volumes for November and December.

FIGURE 14: Average Generation by Technology by Month (2024)



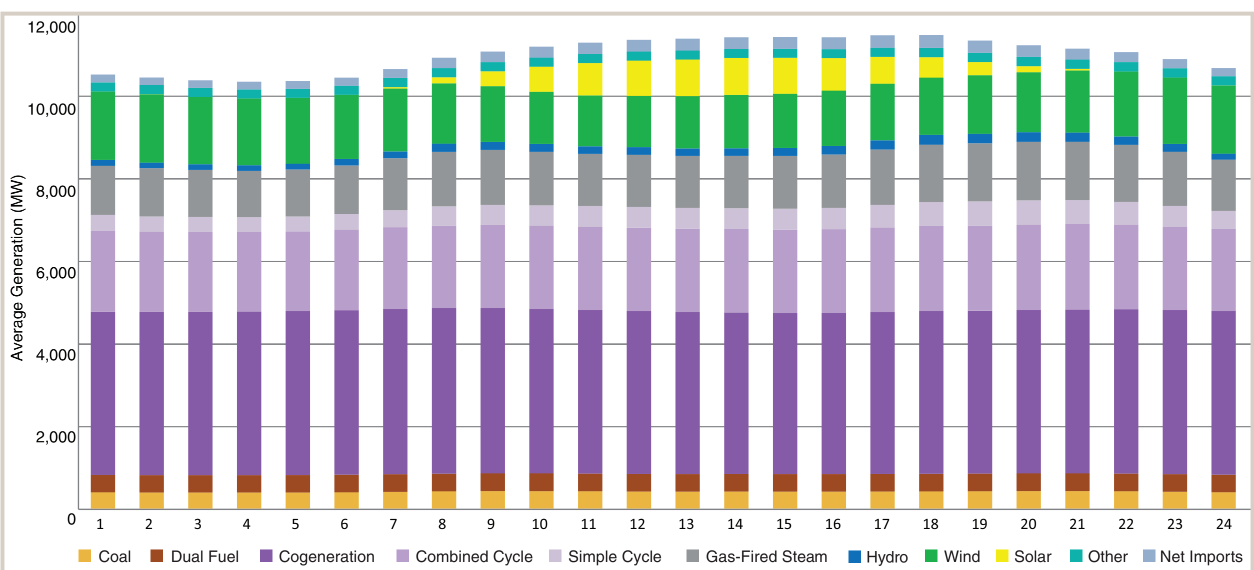
Hourly Average Generation

Alberta's generation mix varies throughout the day due to the daily load patterns and the characteristics of wind and solar generation.

Figure 15 shows the average hourly generation in 2024 and each technology's share of the total.

- Wind generation tends to be slightly higher at night, while solar generation is only available during the day. Also, intermittent generation can be highly variable from hour to hour which is not reflected in the hourly averages in the the chart below (See Flexibility section).
- Dispatchable thermal generation typically peaks during the evening peak hours when demand is highest and solar generation is dropping. Simple-cycle and gas-fired steam assets, often on the margin, accommodate daily variations.

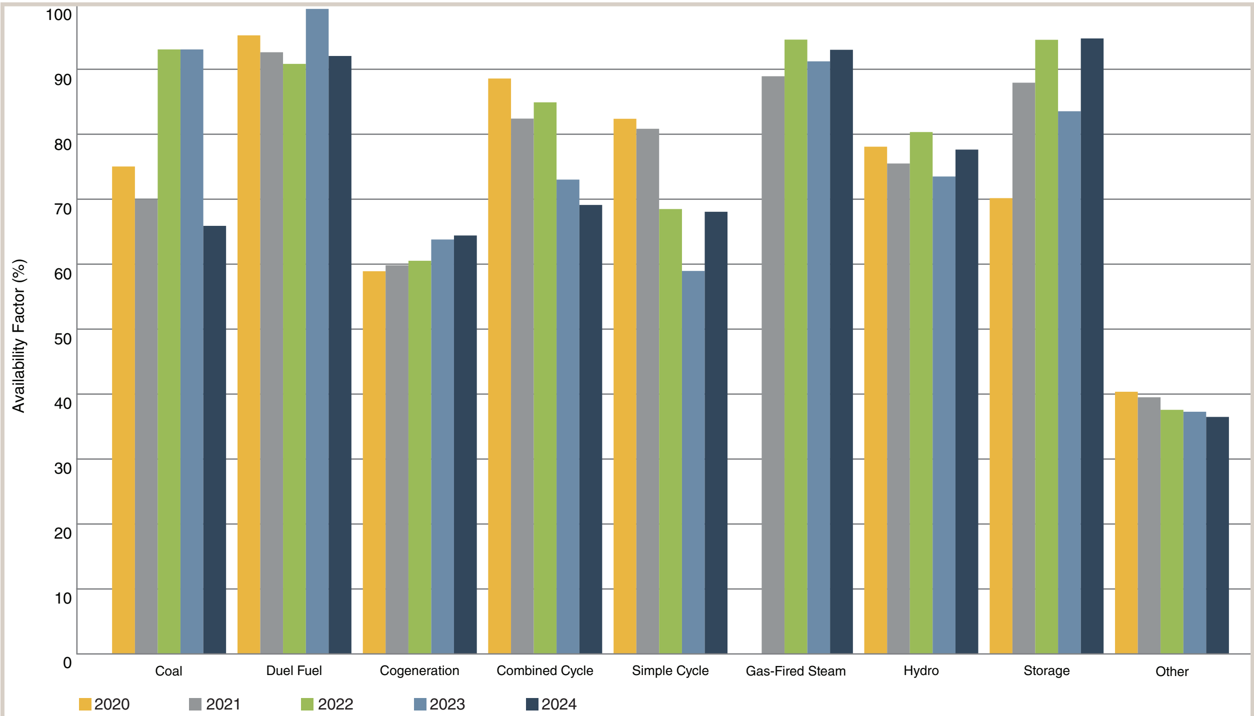
FIGURE 15: Average Generation by Technology by Hour (2024)



Availability Factors and Long-Lead-Time Assets

Figure 16 shows the annual average net-to-grid availability factor for each generation technology.[5]

FIGURE 16: Annual Net-to-Grid Availability Factor by Technology



Key Observations:

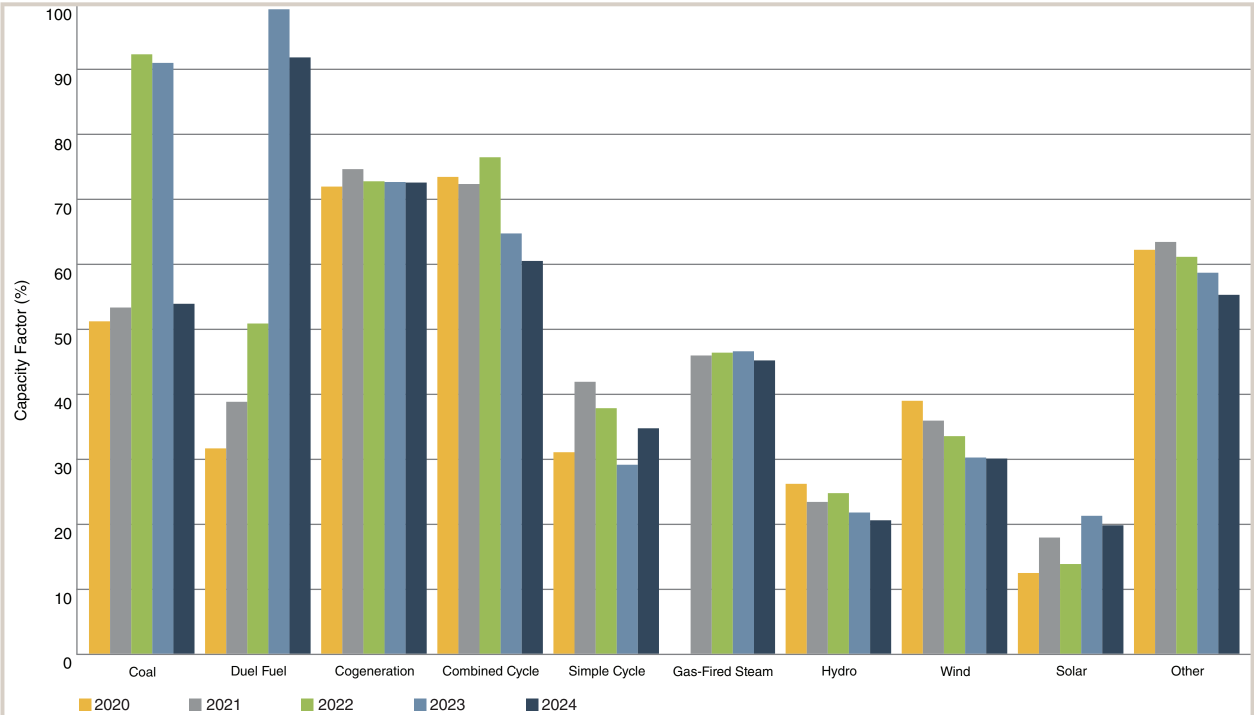
- Newly added assets typically have a lower availability factor during their commissioning phase. This contributed to the lower availability of combined-cycle assets in 2023 and 2024.
- Cogeneration and “Other” fuel type assets mainly serve behind-the-fence load, leaving less capacity for the energy market and results in a lower availability factor.
- Gas-fired steam assets had a high availability factor of 93.2 per cent in 2024, but this includes times when they were commercially offline and required a long lead time (up to 24 hours) to come online and return to full capacity.
  - On average, 19.2 per cent of gas-fired steam capacity was offline in 2024.
  - If commercially offline capacity is excluded, gas-fired steam assets had an availability factor of 74 per cent in 2024.
  - No other fuel types faced long offline periods requiring extended lead times to return to service.

[5] Since it is not available to the energy or ancillary services markets, any generation used to self-supply behind-the-fence load (typically from the cogeneration or other fuel types) is excluded from available energy volume part of the calculation, but the installed capacity is included in the generation capacity volume. Wind and solar generation are also excluded.

Capacity Factor

Figure 17 shows the annual capacity factor by generation technology.[6]

FIGURE 17: Annual Gross Capacity Factor by Technology



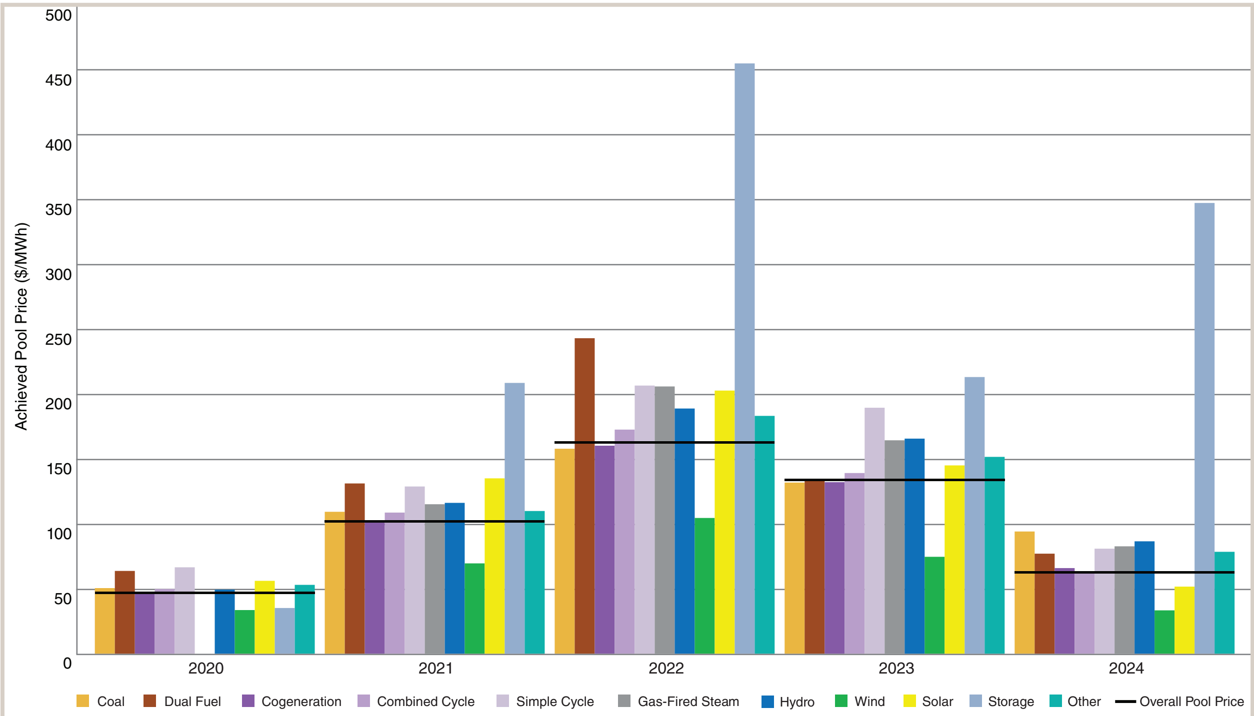
- Dual-fuel had the highest capacity factor at 92 per cent in 2024, represented solely by the asset Genesee #3, which was fully converted to gas-fired steam mid-year.
- Cogeneration achieved the second highest capacity factor at 72 per cent, maintaining stability compared to previous years.
- The capacity factor for combined cycle assets decreased to 60 per cent, reflecting the commissioning phase of new assets.

[6] Energy storage is excluded from this chart, as those assets do not have the ability to provide continuous generation over long periods of time.

Achieved Prices Drop for Most Fuel Types in 2024

Figure 18 shows the achieved price, representing the average price per MWh of electricity delivered to the grid by each technology type.

FIGURE 18: Annual Achieved Price by Technology

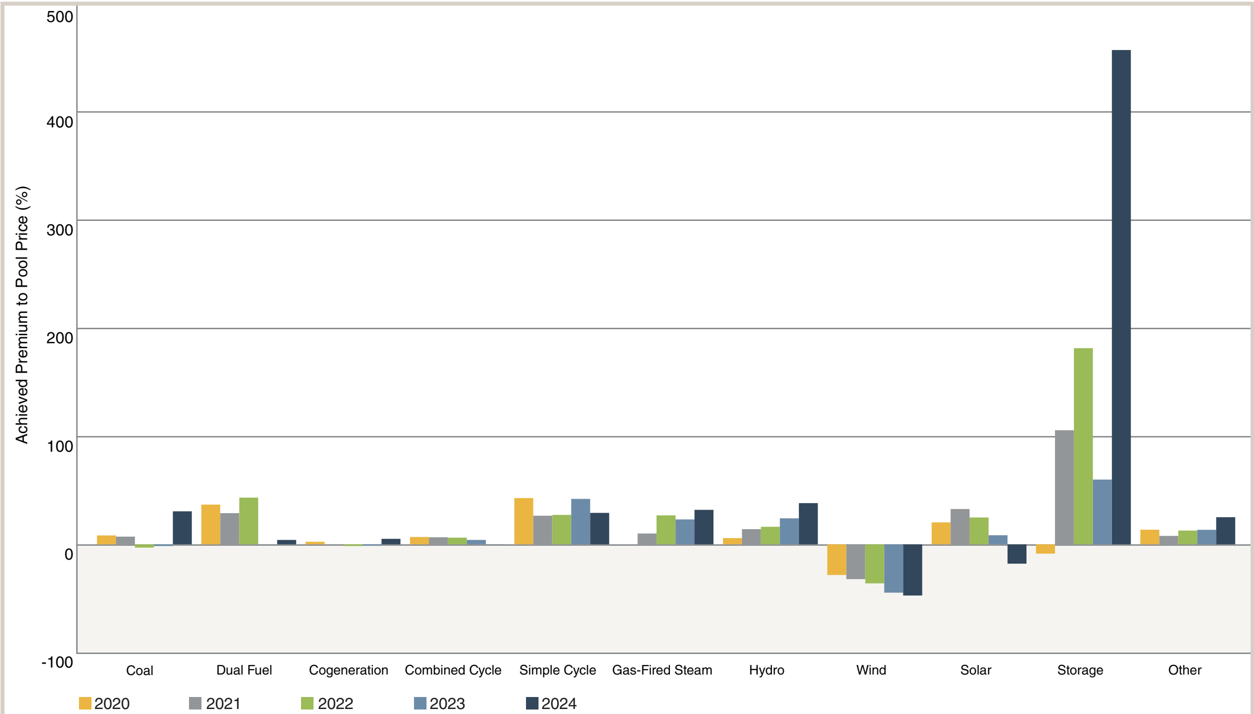


Key Observations:

- Lower average pool prices in 2024 resulted in a decline in the achieved price for most asset types compared to 2023.
- Energy storage assets, which supply power during a few select high-priced hours, realized an average price of $346.56/MWh in 2024.
  - This was driven by occasional periods of very high-priced hours, despite the overall lower average price.

Figure 19 shows the achieved premium-to-pool price for each generation technology over the past five years.

FIGURE 19: Annual Achieved Premium-to-Pool Price



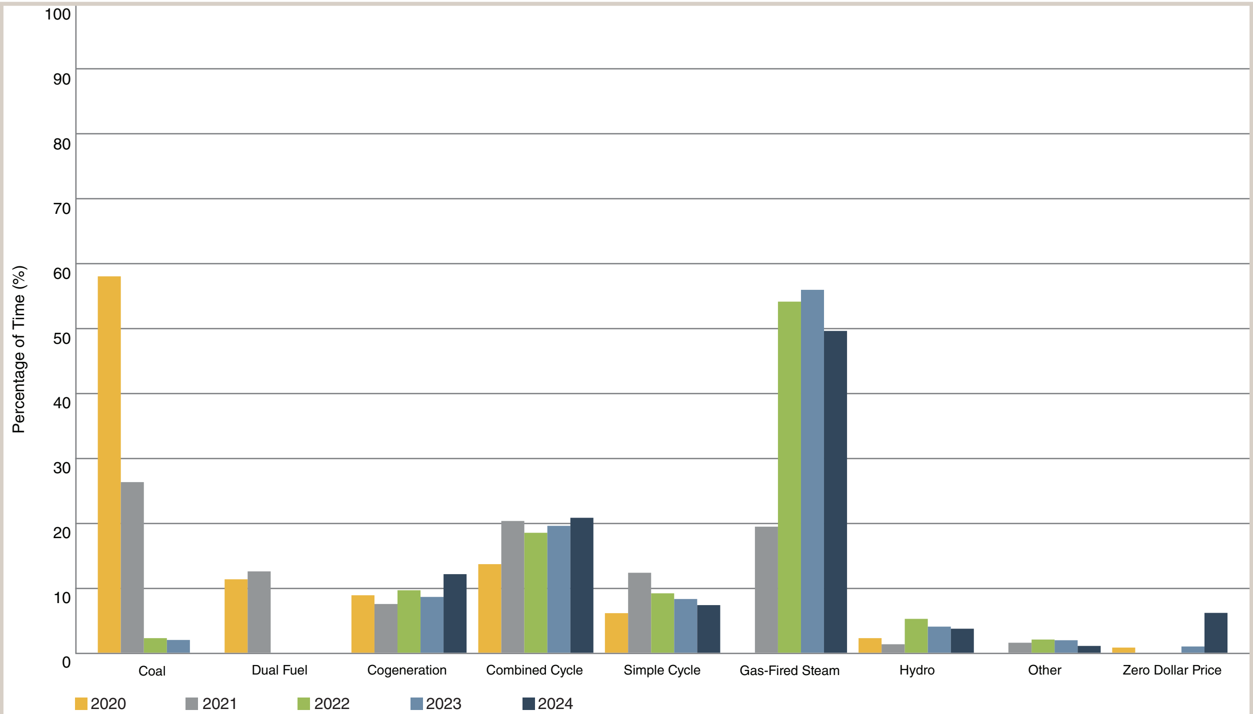
Key Observations:

- Combined cycle and cogeneration assets operated at baseload in 2024 and achieved prices near the average pool price.
- Simple-cycle, gas-fired steam and hydro units were dispatched during higher-priced hours because they were offered higher in the merit order.
- Wind generation achieved an average of 47 per cent less than the average pool price in 2024. This is because wind output is highest at night when pool prices are typically lower. In addition, many wind assets typically produce electricity at the same time, which pushes prices down for all generation sources. As more wind generation has been added, this price effect has intensified, leading to larger price discounts over time.
- Solar generation achieved an average of 18 per cent less than the average pool price in 2024. Prior to 2024, solar generation achieved higher prices because it generates electricity during the day when prices tend to be higher. In 2024, the growing number of solar farms created a similar effect as wind, where many solar farms producing electricity at the same time drove prices down.

Marginal Price-Setting Technologies

Figure 20 shows how often each generation technology type set the system's marginal price over the last five years.

FIGURE 20: Annual Marginal Price-Setting Technology



- New combined cycle, cogeneration, wind, and solar capacity in 2024 led to:
  - Gas generation was on the margin 89 per cent of the time, with gas-fired steam (49 per cent) and combined cycle (21 per cent) setting the marginal price most often.
  - About six per cent of hours had a $0 marginal price,[7] with no specific technology assigned to those hours. Some volume from multiple different technologies is offered at that price.

Wind Generation

Table 5 summarizes annual wind generation statistics over the last five years, showing significant growth.

TABLE 5: Annual Wind Generation Statistics

Year	2020	2021	2022	2023	2024
Installed wind capacity at year end (MW)	1,781	2,269	3,618	4,481	5,688
Maximum Hourly Generation (MWh)	1,704	1,933	2,208	3,683	3,993

[7] When the marginal price is zero dollars, a supply surplus may be called if the amount of supply offered at zero dollars exceeds the amount needed to meet demand. If this occurs, all flexible zero-dollar energy offers, regardless of type, are proportionally reduced.

Year	2020	2021	2022	2023	2024
Total wind generation (GWh)	6,079	6,133	7,314	10,283	12,797
Wind generation as a percentage of total AIL (Average)	7%	7%	8%	12%	14%
Wind generation as a percentage of total AIL (Maximum)	20%	20%	24%	37%	42%
Average hourly capacity factor	39%	36%	33%	30%	30%
Maximum hourly capacity factor	96%	95%	91%	82%	84%
Wind capacity factor during annual peak AIL	8%	16%	17%	18%	24%

Key Observations:

- In 2024, five new wind facilities with a combined capacity of 1,186 MW connected to the grid.
- Their combined maximum output only reached 812 MW, suggesting they were not fully completed during the year.
- Since 2020, total wind capacity has increased nearly 220 per cent, while total output has increased by 110 per cent.

Figure 21 shows the installed wind generation capacity and the monthly range of hourly wind generation.

Wind farms connected to the grid since late 2022 have taken up to 12 months to reach near maximum capacity. Most new generation added in 2024 is expected to be fully operational in 2025.

FIGURE 21: Monthly Average Wind Capacity and Generation

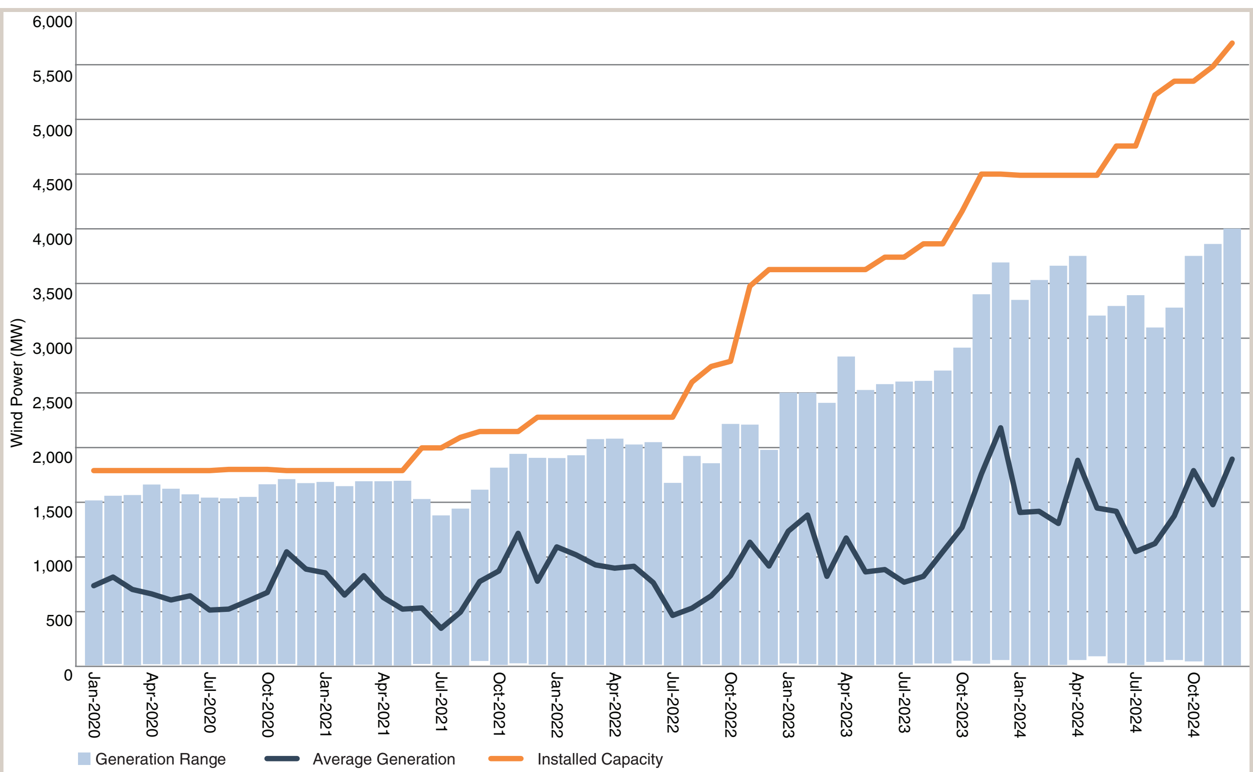
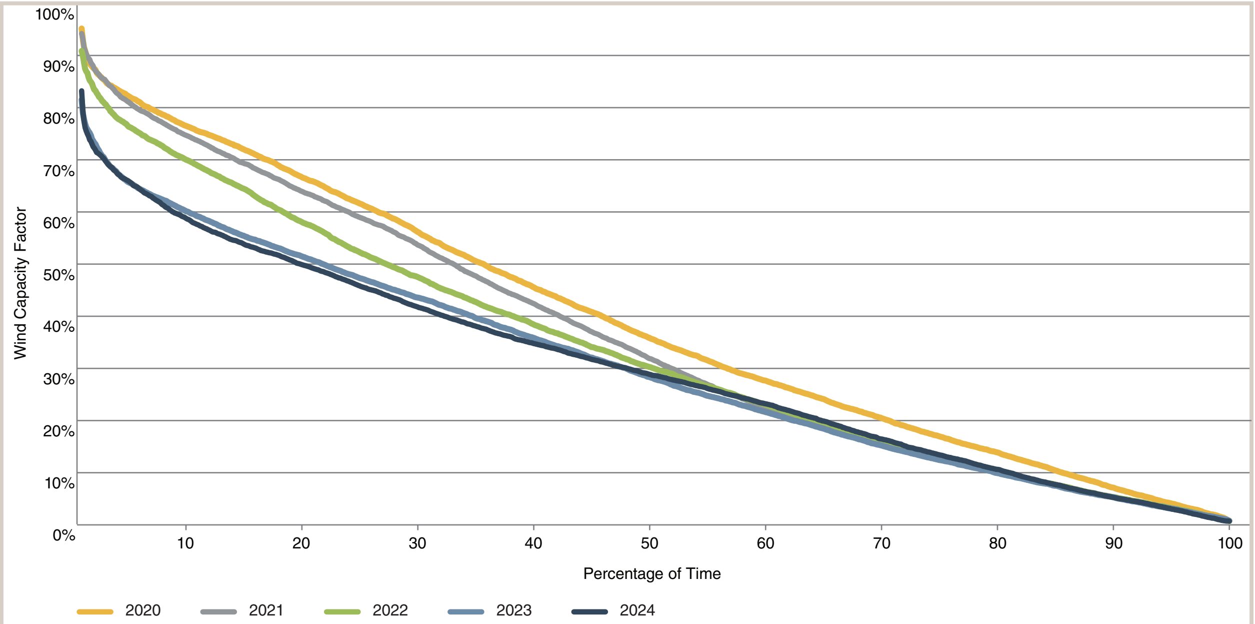


Figure 22 shows annual duration curves for Alberta's wind generation capacity factors. The duration represents the percentage of time wind generation met or exceeded specific capacity factor values.

FIGURE 22: Annual Wind Capacity Factor Duration Curves

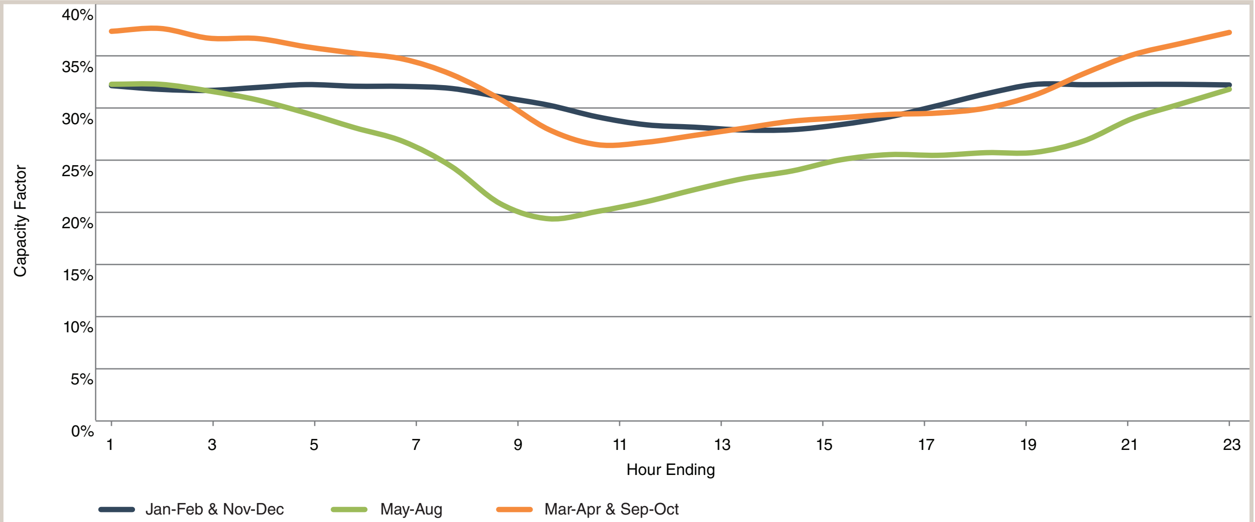


Key Observations:

- The average capacity factor in 2024 was consistent with 2023 but lower than in 2022 and previous years.
- Much of this decline was due to delays in new capacity fully operating, with the 1,186 MW added in 2024 having an average capacity factor of only four per cent.
- Transmission constraints and more supply surplus curtailments also limited generation.

Figure 23 shows the average hourly capacity factor of wind generation in 2024. Wind generation tends to peak overnight and drop during midday, a trend seen more often in summer than in winter.

FIGURE 23: 2024 Wind Generation Seasonal Average Hourly Output



Key Observations:

- Wind generation peaks in winter and drops in summer, following a seasonal pattern. Strong winds are more common in winter, but extreme weather like polar vortexes or heat waves can weaken wind output during high-demand periods.
- Wind generation is highest overnight and lowest midday, especially in summer. Delays in connecting new capacity in 2024 further reduced winter capacity factors.

Regional Wind

Wind generation was located exclusively in southern Alberta until early 2011. Since then, new wind facilities in central Alberta have increased the geographic diversification of wind generation.

Table 6 shows regional wind generation statistics for 2024.

TABLE 6: 2024 Regional Wind Statistics

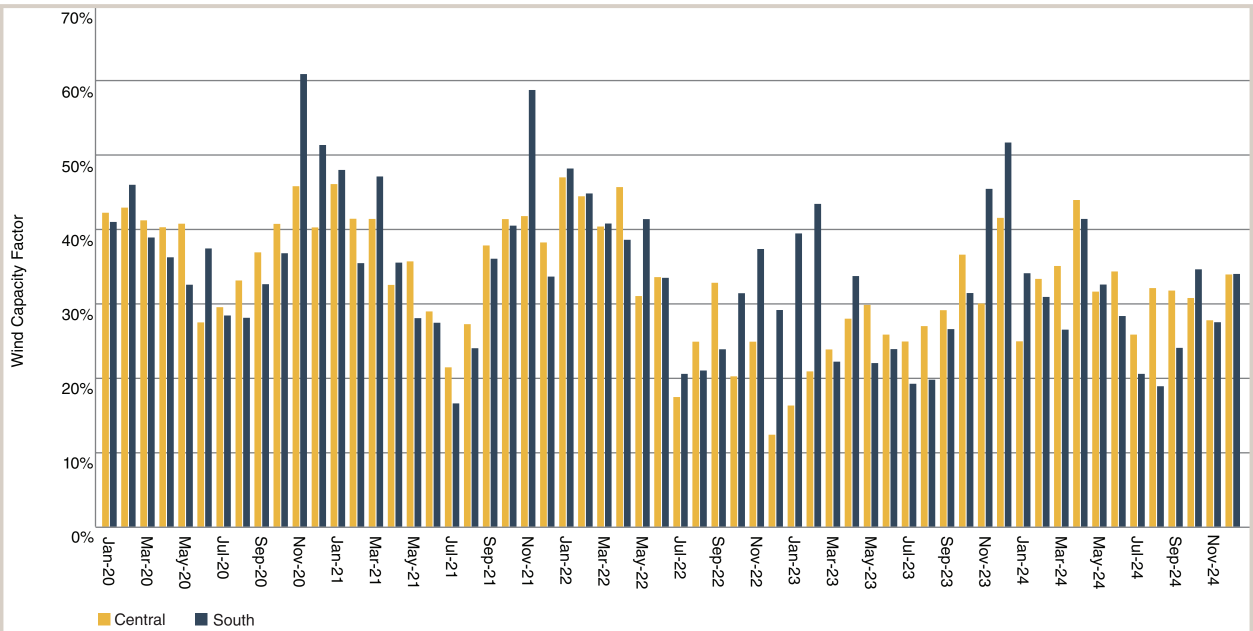
Region	Central	South	Total
Installed wind capacity at year end (y/y change) (MW)	1,460 (+126)	4,228 (+1,081)	5,688 (+1,207)
Total wind generation (y/y change) (GWh)	2,289 (+1,549)	7,995 (+964)	12,797 (+2,514)
Average wind capacity factor (y/y change)	31.9% (+4.2%)	29.3% (-2%)	30% (-0.4%)
Achieved price ($/MWh)	$35.39	$32.57	$33.41

- **South**: Four new facilities were connected in 2024, bringing the total to 39. The 34 per cent increase in installed capacity impacted the capacity factor as many facilities were still commissioning during the year. The achieved prices in this region are lower due to the large amount of highly correlated installed capacity.

- **Central**: One new facility started operating in 2024, bringing the total to 11. Units connected in 2023 operated at full capacity for most of 2024, resulting in a higher capacity factor. Wind generation in this region typically achieves higher prices compared to the South due to lower installed capacity. However, as more wind generation is installed, the combined impact will increasingly reduce the achieved price for all wind assets.

Figure 24 shows the monthly average capacity factor by region over the past five years.

FIGURE 24: Monthly Wind Capacity Factor by Region



Solar Generation

Key Observations

- Two new solar facilities with a combined capacity of 149 MW were added to the grid in 2024. However, their combined maximum output was only 27 MW, indicating they were not able to deliver their full capacity during the year.
- Three existing units increased their capacity by a combined total of 13 MW.
- Over 300 MW of solar generation installed under the *Micro-generation Regulation* is not included in these figures. These sites, which include rooftop solar, connect to distribution networks and don't report actual generation values to the AESO.

More details on micro-generation assets can be found here: Micro- and Small Distributed Generation Reporting.

Table 7 summarizes the annual statistics for solar generation over the last five years.

TABLE 7: Annual Solar Generation Statistics

Year	2020	2021	2022	2023	2024
Installed solar capacity at year end (MW)	107	736	1,138	1,650	1,812
Maximum Hourly Generation (MWh)	79	302	819	1,157	1,502
Total solar generation (GWh)	20	86	477	1,164	2,882
Solar generation as a percentage of total AIL (Average)	0%	1%	1%	3%	3%
Solar generation as a percentage of total AIL (Maximum)	1%	3%	8%	12%	15%
Average hourly capacity factor	12%	18%	14%	21%	20%
Maximum hourly capacity factor	93%	98%	78%	93%	91%
Solar capacity factor during annual peak AIL	0%	0%	0%	1%	0%

Figure 25 shows the monthly average generation of solar assets over the last five years, excluding overnight hours when there is no solar generation. Solar facilities, apart from the 465-MW Travers solar asset launched in 2022, typically reach commercial operation faster than wind facilities due to their smaller size.

FIGURE 25: Monthly Average On-Peak Solar Capacity and Generation

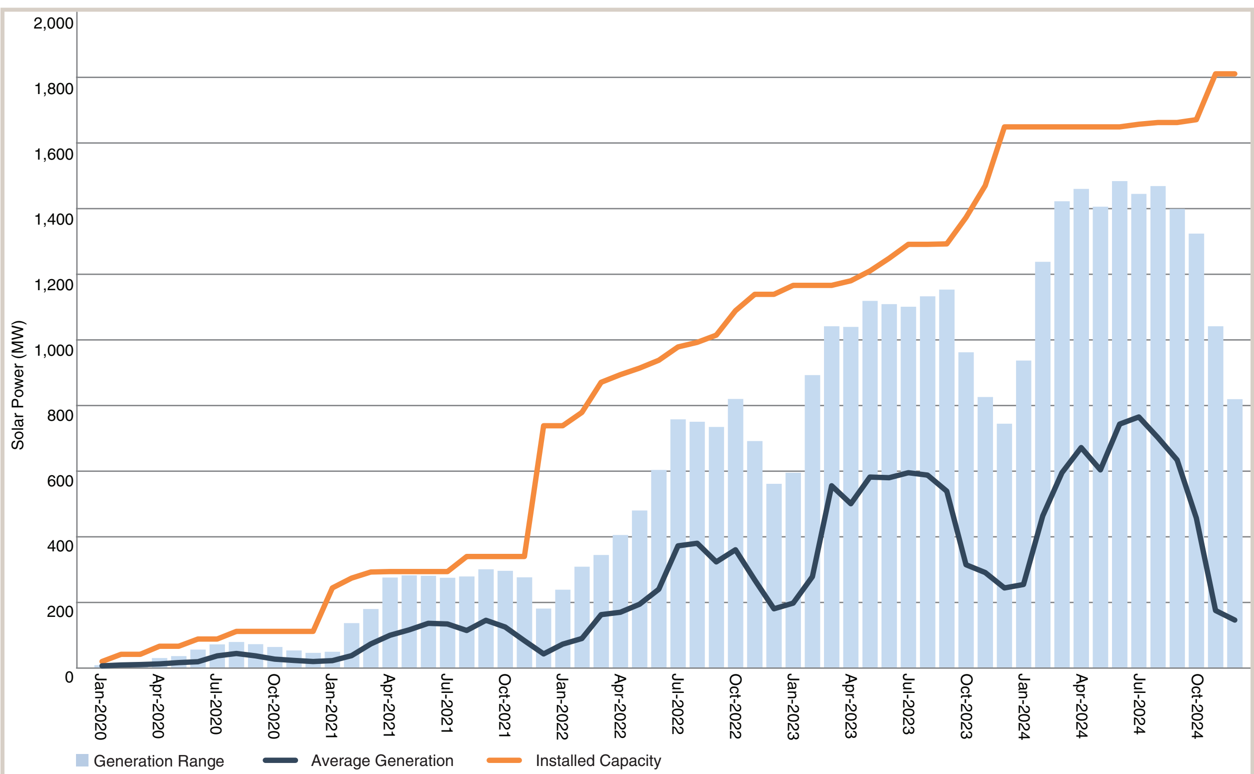
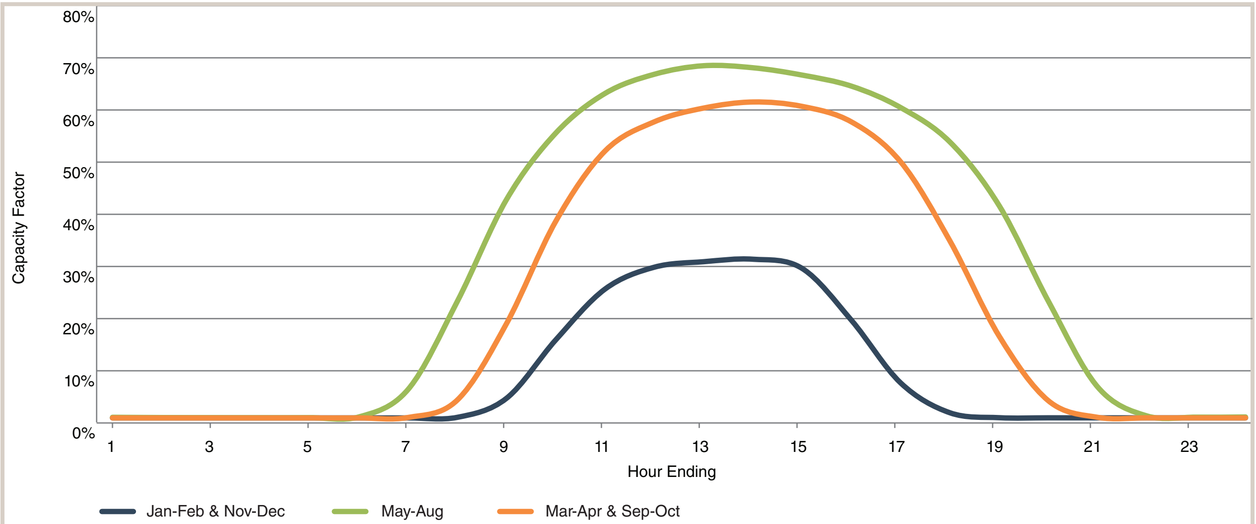


Figure 26 shows the average hourly solar generation different periods of the year during 2024. Peak generation occurs between 10:00 a.m. to 3:00 p.m., with the summer and shoulder months extending the peak solar generation hours into the morning and early evening.

FIGURE 26: 2024 Seasonal Average Hourly Output of Solar Fleet



Interim Market Power Mitigation Rules

In March 2024, the Alberta government announced regulatory changes regarding economic withholding in the energy market and enacted two new regulations, the *Market Power Mitigation Regulation* (MPMR) and the *Supply Cushion Regulation* (SCR). To satisfy the new regulations, the AESO implemented the Interim Market Power Mitigation Rules which consist of the Secondary Offer Cap (SOC) and the Supply Cushion Directives (SCD) rules.

- The SOC implements a secondary offer price limit once a certain net revenue threshold has been reached in a month.
- The SCD requires the AESO to direct long lead time assets online when the AESO's supply cushion is forecasted to be below a 932 MW specified threshold.
- The SOC and SCD are implemented through Section 206.1 and Section 206.2 of the ISO rules, respectively, which came in effect July 1, 2024.

Secondary Offer Price Cap

After implementation, the secondary offer price limit was in effect for only one period, from hour-ending 02:00 on July 23 through the end of July.

Supply Cushion Directives

The AESO issued a total of 23 Unit Commitment directives under the SCD rule to five eligible long lead time assets to operate in a total of 135 settlement intervals in 2024.

Imports and Exports

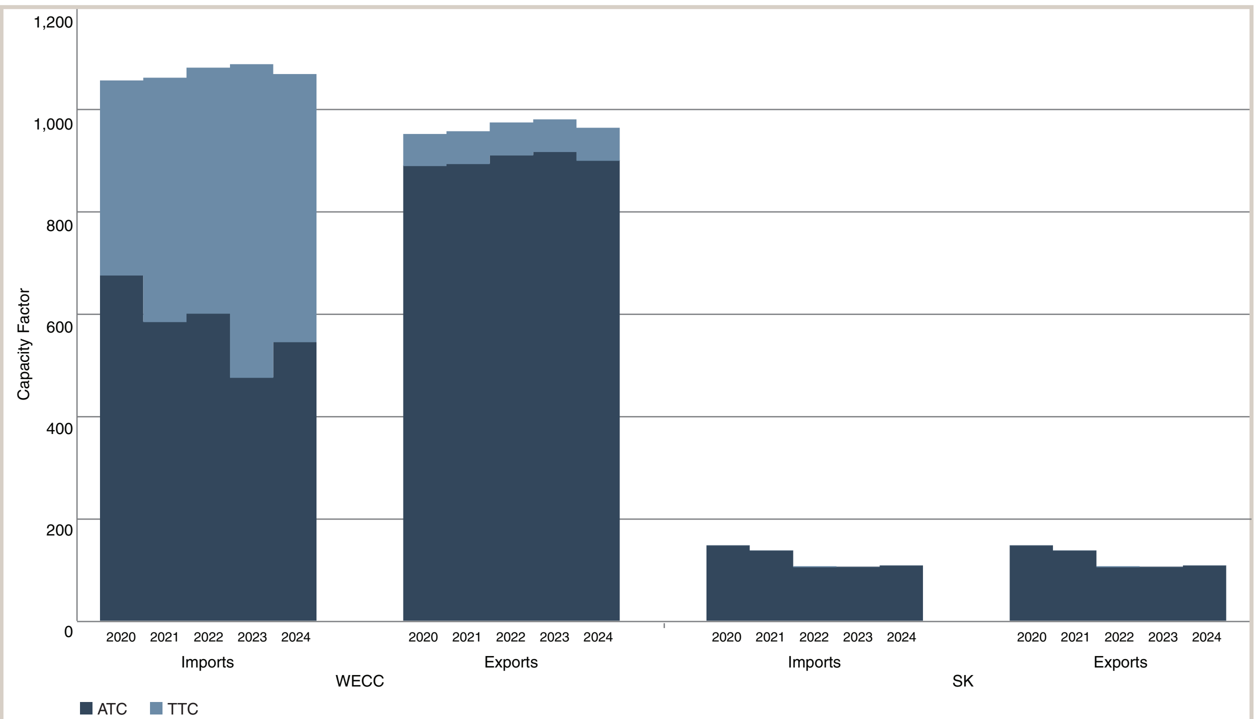
Alberta transfers electricity through interties with British Columbia (B.C.), Montana (MATL) and Saskatchewan (SK).

Import ATC up 70 MW due to Increased FFR Volumes

Figure 27 shows the average Total Transmission Capability (TTC) between Alberta, other Western Electricity Coordinating Council (WECC) members[8] and Saskatchewan. The average Available Transfer Capability (ATC) is shown for comparison.

- Average import ATC for the WECC interties (B.C. and MATL) increased by 70 MW in 2024 compared to 2023 due to increased Fast Frequency Response (FFR) volumes.
- Outages on the SK intertie, both partial and full, reduced its average capacity during 2022, 2023, and 2024. A full outage started October 4, 2024, and extended into 2025.

FIGURE 27: Average Annual Path Rating by Transfer Path



[8] Alberta, B.C., and Montana are members of the WECC region while Saskatchewan is part of the Midwest Reliability Organization (MRO). 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.

Alberta a Net-Exporter in 2024

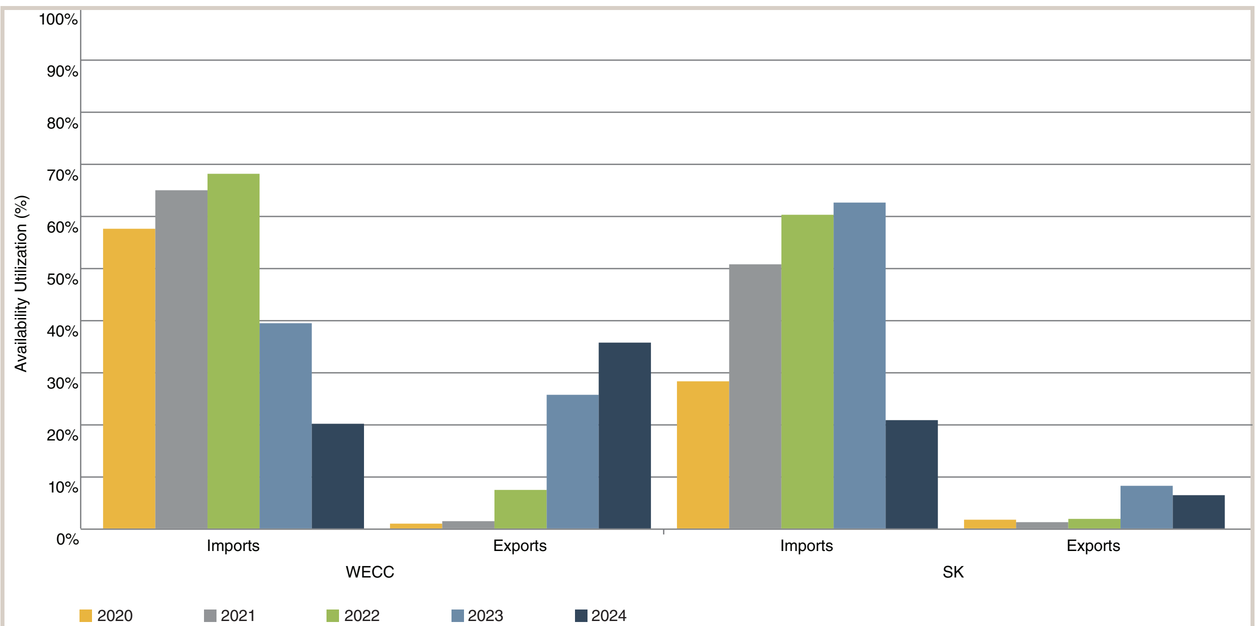
Alberta was a net-exporter of electricity in 2024 where exports exceeded imports for the first time since 2016, continuing a trend of declining import volumes that began in late 2022. This shift was largely due to:

- Low water levels affecting hydroelectric generation in B.C. and the broader Pacific Northwest.
- Increasing electricity supply in Alberta that lowered pool prices.

Figure 28 shows annual availability utilization[9] rates for energy transfers between Alberta, WECC members and Saskatchewan.

- Import availability utilization from WECC dropped compared to 2023, averaging 20 per cent in 2024, while WECC export utilization rose to 36 per cent.
- Saskatchewan intertie usage fell for both imports and exports in 2024.

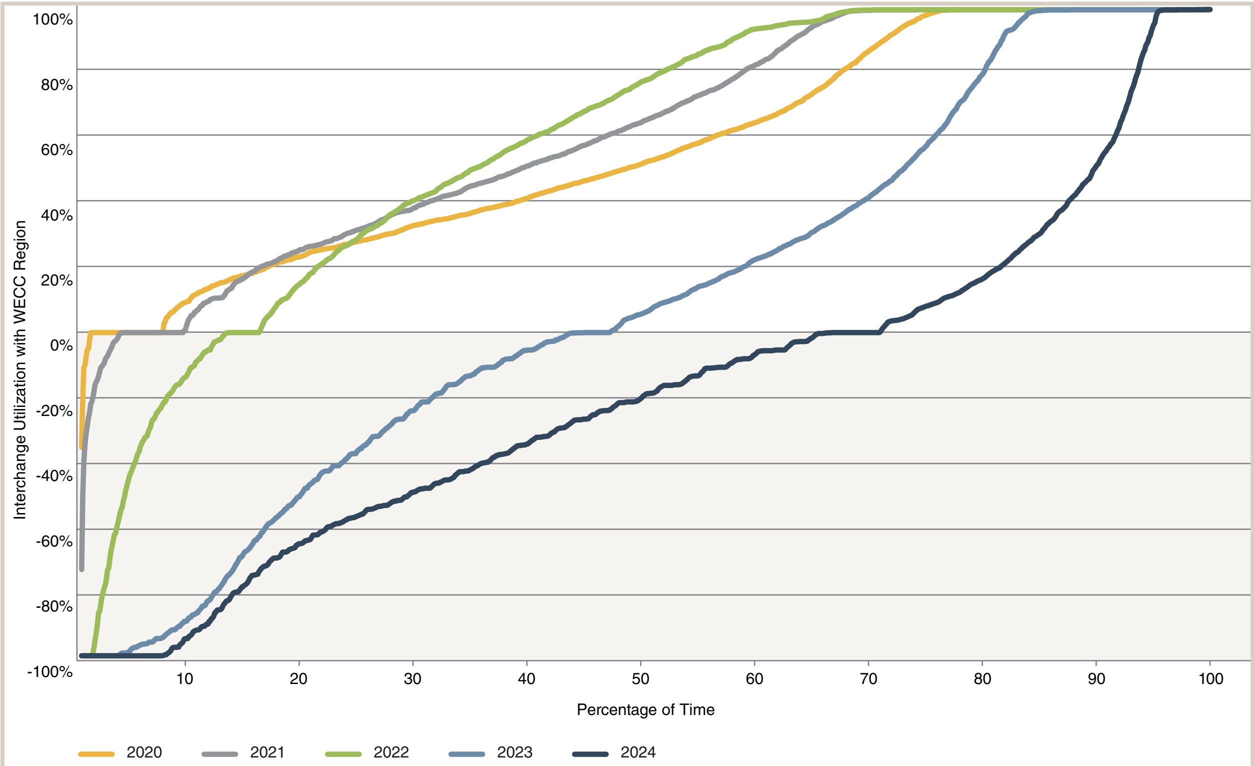
FIGURE 28: Annual Availability Utilization by Transfer Path



[9] Availability utilization is the percentage of available transfer capability (ATC) used to transfer energy between jurisdictions.

Figure 29 shows the annual interchange utilization between Alberta and the WECC regions over the past five years.

FIGURE 29: Annual Interchange Utilization with WECC Region



Key Observations:

- Alberta was a net-exporter to WECC in 67 per cent of the hours in 2024.
- Export ATC limited WECC exports in approximately eight per cent of hours, while the import ATC limited imports in only five per cent of hours.
- By comparison, the WECC import ATC limited imports in 33 per cent of hours in 2022.

Figure 30 shows the annual interchange utilization between Alberta and Saskatchewan over the past five years.

- Alberta was a net-importer from Saskatchewan in 2024. However, flows were at zero for 49 per cent of the year, partly due to an extended outage covering most of October to December.

FIGURE 30: Annual Interchange Utilization with Saskatchewan

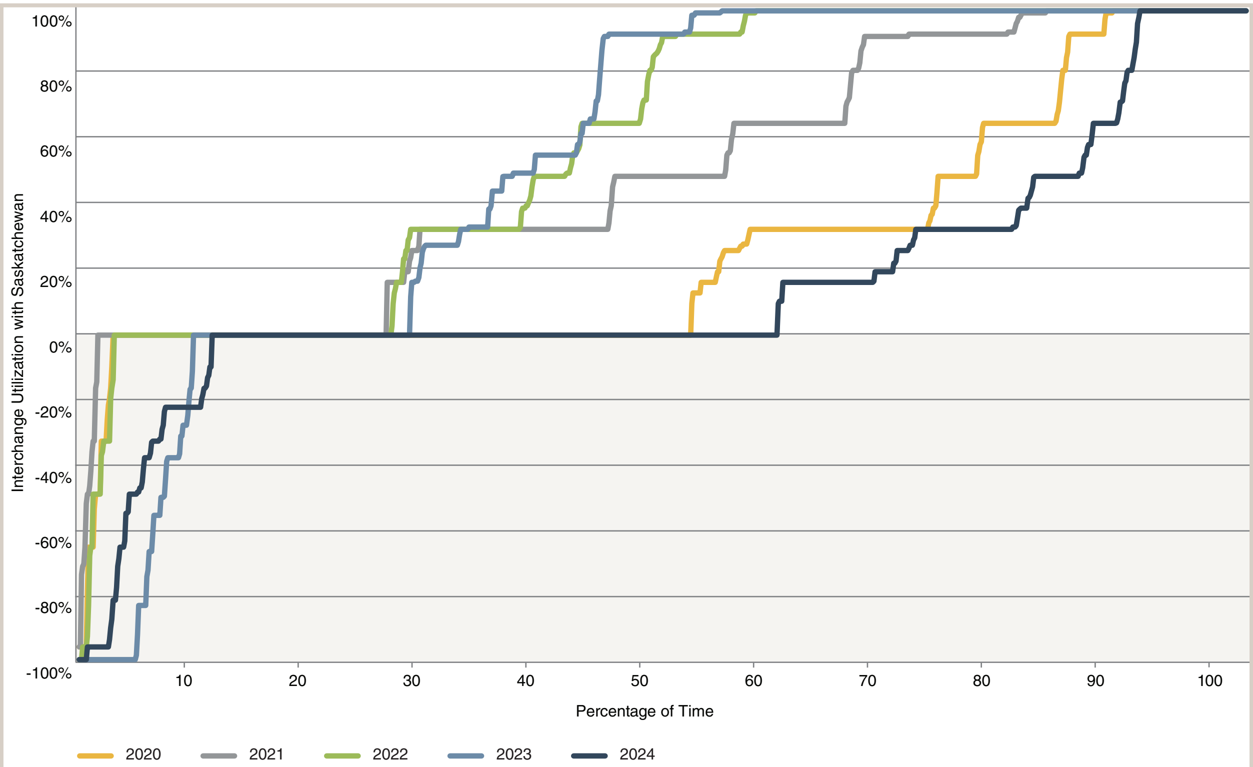
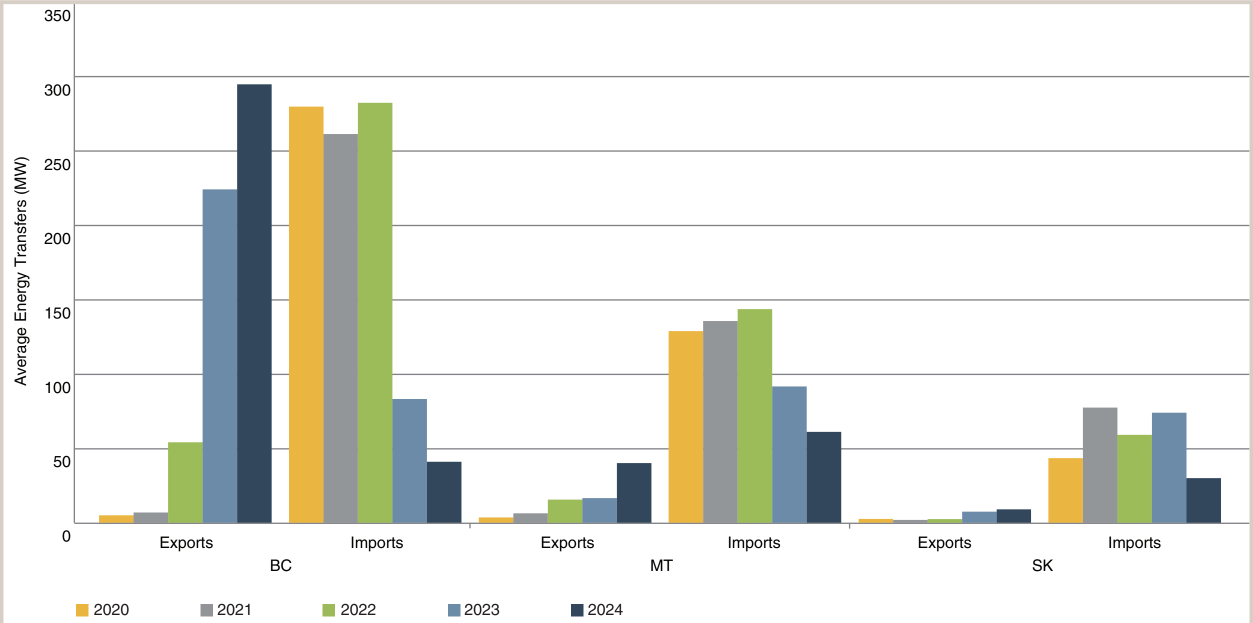


Figure 31 shows the annual average energy transferred from each province or state.

FIGURE 31: Annual Intertie Transfers by Province or State



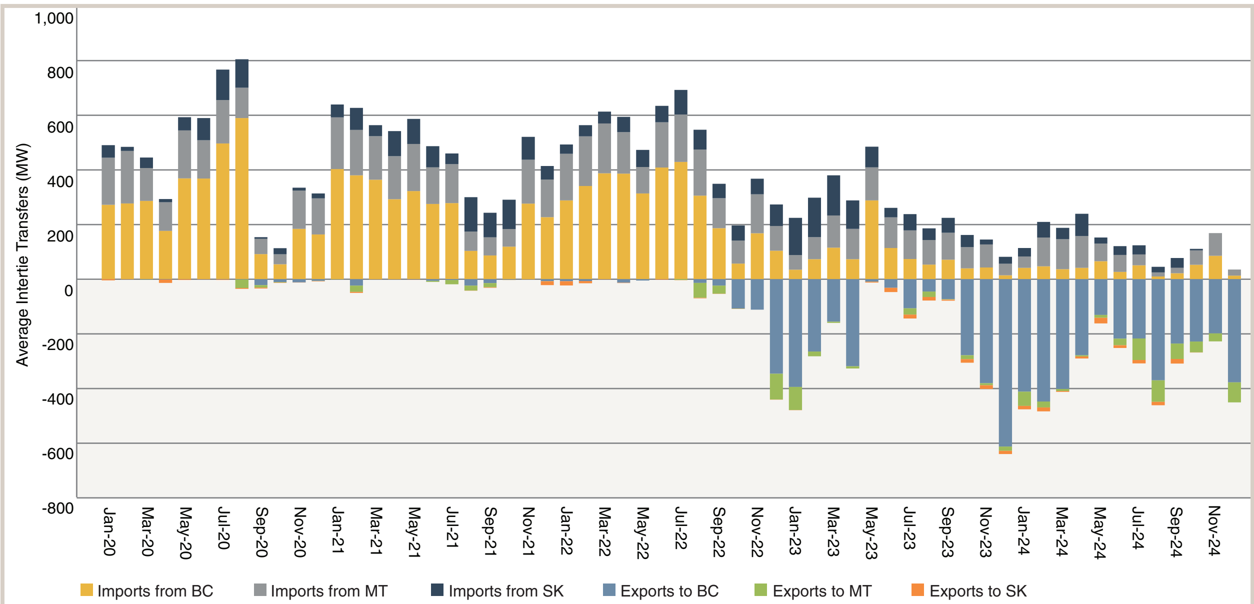
Key Observations:

- Average total exports exceeded imports by 212 MW in 2024.
    - Average exports were 343 MW, while imports averaged 132 MW.
- Most Alberta exports went to B.C., while Montana and Saskatchewan remained net-importers to Alberta.
- More electricity was imported through the MATL line than from B.C. or Saskatchewan. However, MATL saw an increase in exports and a decrease in imports compared to previous years.

Figure 32 shows the monthly average energy transferred between Alberta and neighboring provinces or states.

- Alberta's total monthly exports exceeded imports each month of 2024.
- Net-exports were lowest in May when spring runoff at hydro facilities in B.C. partially reduced demand for Alberta's exports.
- Since late 2022, dry conditions in B.C. and increased supply in Alberta have driven a shift from imports to exports, especially on the B.C. intertie.

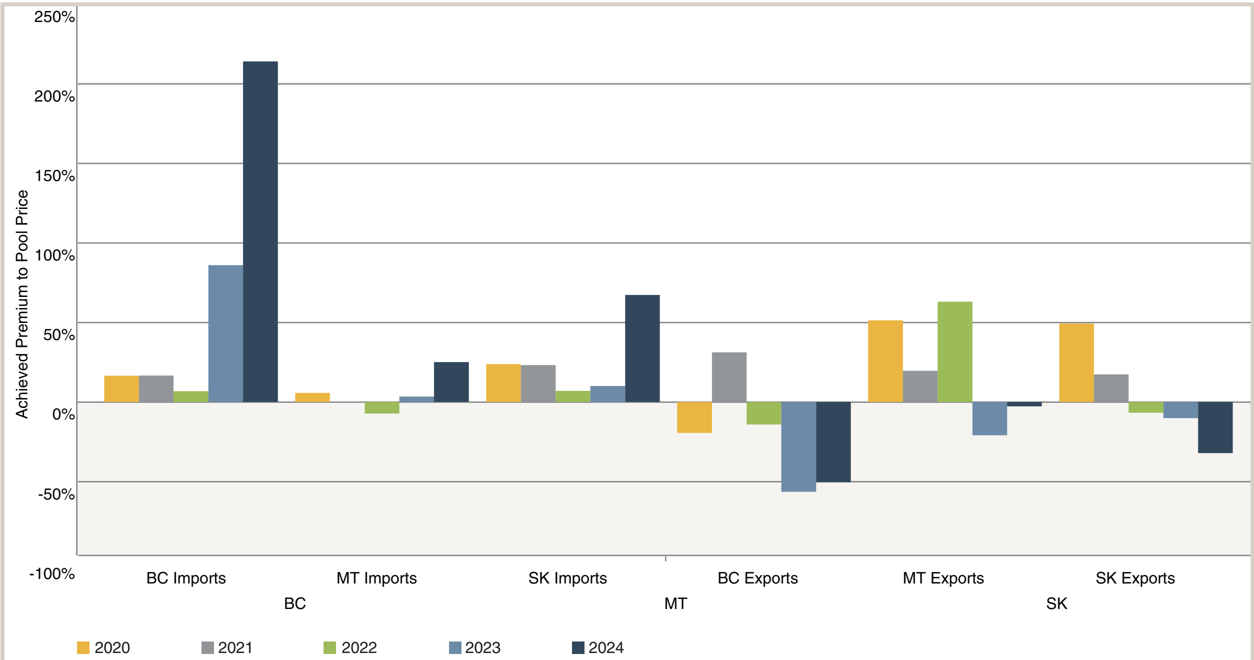
FIGURE 32: Monthly Average Intertie Transfers



Net-Exports More Common in Low-Priced Hours

Figure 33 shows the achieved premium-to-pool price on imported energy by province or state.

FIGURE 33: Annual Achieved Premium-to-Pool Price on Imported Energy

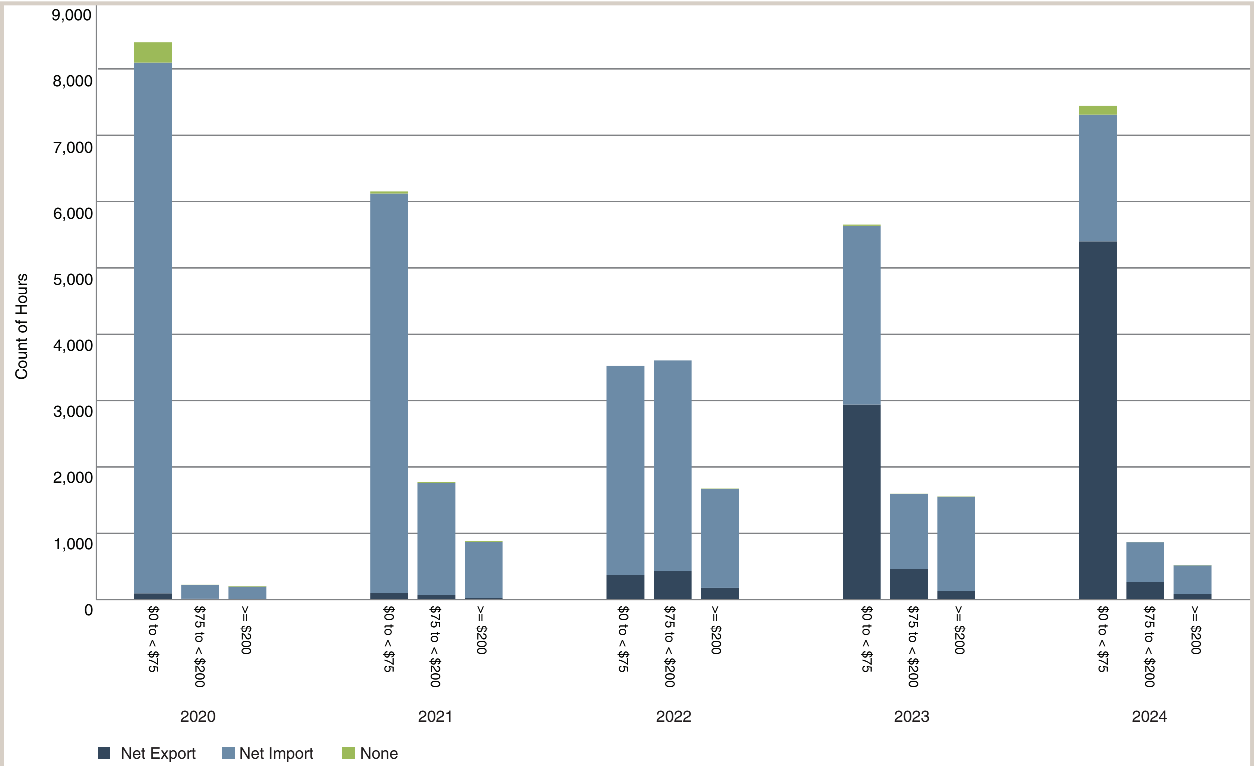


Key Observations:

- Import prices were higher than the overall average pool price on all three interties, while export prices were below the overall pool price.
- This reflects intertie usage adjusting to Alberta's price conditions, with imports occurring during high-priced hours and exports during low-priced hours.
- Imports from B.C. achieved prices 214 per cent higher than the overall average pool price in 2024, as the small volume of imports were received only in the highest priced hours.

Figure 34 shows the frequency of hours with net-total imports or exports based on the pool price during those hours.

FIGURE 34: Yearly Count of Hours by Price and Net Import/Export Status



Key Observations:

- From 2020-2022, net imports occurred more often than net-exports across all price categories.
- In 2023 and 2024, low-priced hours became more frequent compared to 2022. Exports during those low-priced hours also increased significantly.
- Imports were still more common than exports during hours when prices exceeded $75. However, since 2022, all price categories have included some exports.

Supply Adequacy

Supply adequacy measures the system's ability to meet electricity demand. This section reviews past performance and a detailed analysis of future supply adequacy is available in the AESO's quarterly Long-Term Adequacy Metrics report.

Generation Outages Higher due to Commissioning

When new assets are added to the grid, they undergo a commissioning phase which can last several months. During this phase, available capacity (AC) is lower than the posted maximum capacity (MC), and generation volumes are based on test plans instead of pool prices. When an asset's AC is below the MC, it's considered either in an outage or derated if not fully offline.

- In 2024, Cascade 1 and 2 and Genesee Repower 1 and 2 contributed to combined-cycle commissioning-related outages.
- New wind capacity added in 2024 also resulted in commissioning-related outages.

Figure 35 shows the average generation outages by fuel type over the last five years.

FIGURE 35: Annual Hourly Average Generation Outages by Fuel Type

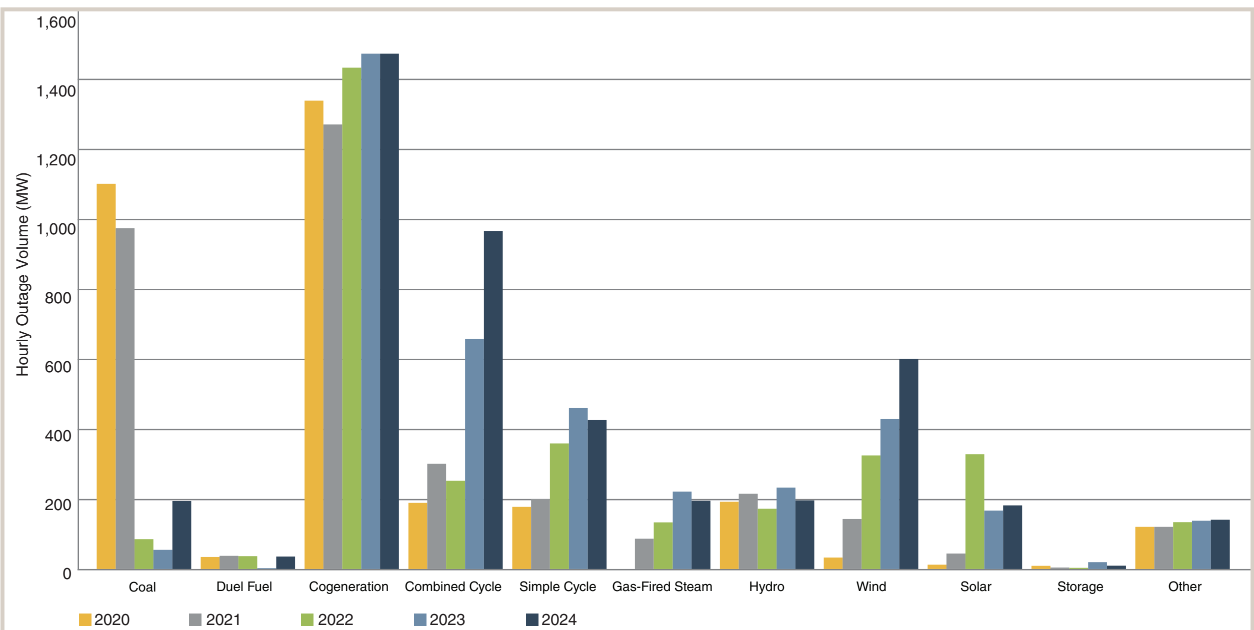
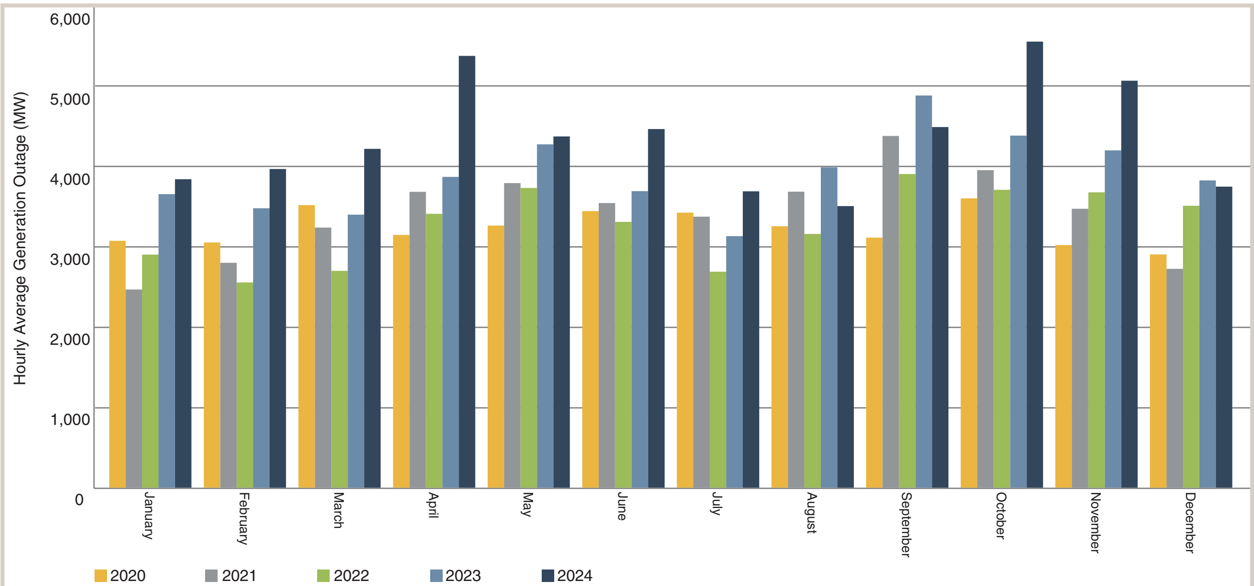


Figure 36 shows the hourly average generation outage volume by month for the last five years.

- Planned generation outages are typically seasonal and peak during the shoulder periods, from mid-April to mid-June and late-September to early November, when demand is lowest, and any outages have the least impact.
- Through Q2 2024, outages were higher due to the commissioning activities at both gas and intermittent generating facilities. Many of these outages were unplanned.
- October and November 2024 saw a significant increase in planned maintenance outages at gas generating facilities.

FIGURE 36: Generation Outages by Month



Average Supply Cushion Increased 14 per cent

The hourly supply cushion represents the extra energy in the merit order available for dispatch after meeting demand.

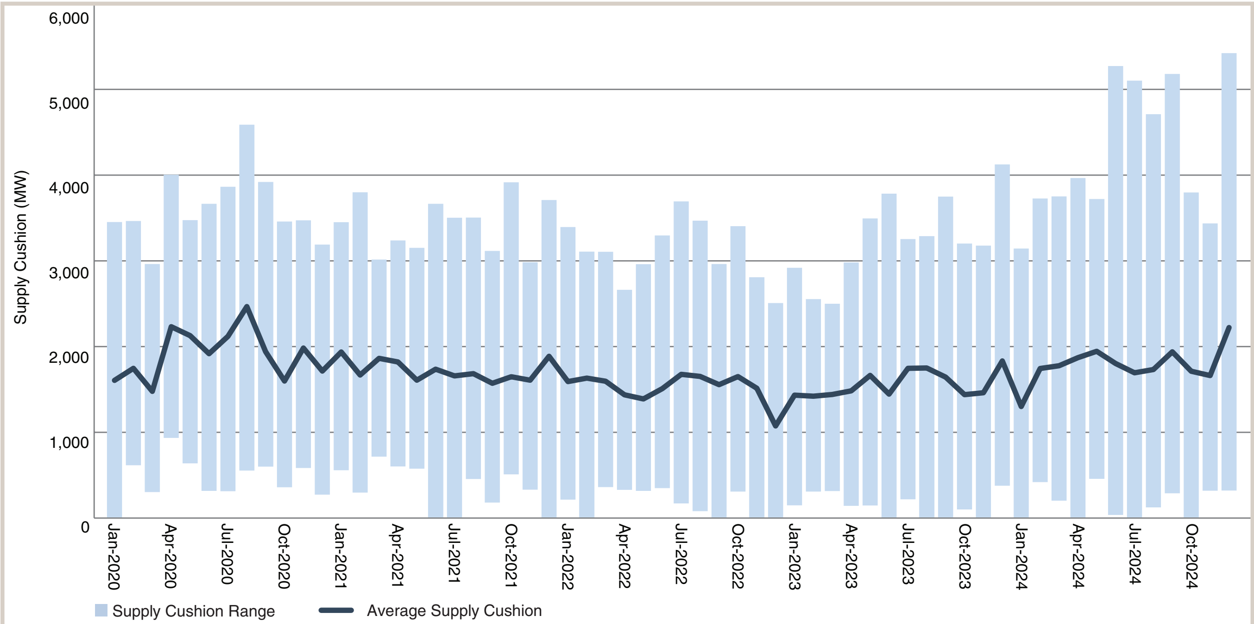
- In 2024, the average supply cushion increased by 14 per cent compared to 2023, driven by the additions of new supply.

TABLE 8: Supply Cushion Summary by Year

Year	2020	2021	2022	2023	2024
Minimum Supply Cushion (MW)	0	0	0	0	0
Average Supply Cushion (MW)	1,923	1,735	1,530	1,574	1,794
Maximum Supply Cushion (MW)	4,628	3,950	3,725	4,161	5,471

Figure 37 shows the monthly average of the supply cushion over the last five years, along with the range of supply cushion values for each month.

FIGURE 37: Monthly Supply Cushion



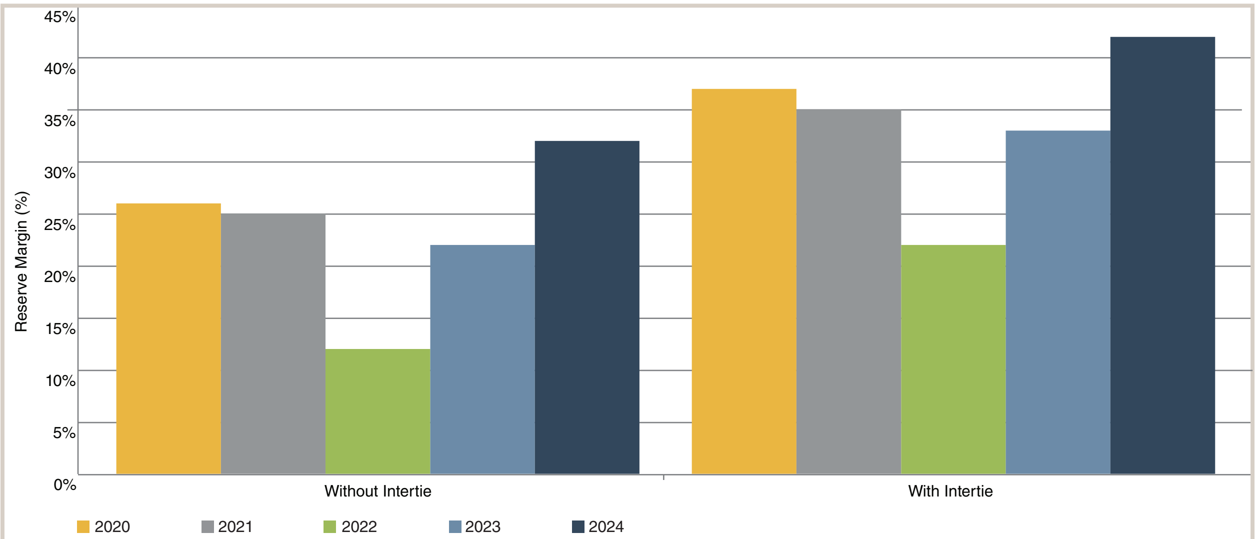
Reserve Margin Increased 10 Per Cent

Reserve margin measures the system generation capability above what is needed to meet peak system load.[10]

Figure 38 shows the annual reserve margin over the past five years.

- In 2024, the reserve margin without intertie increased to 32 per cent, driven by the addition of new gas-fired generation.

FIGURE 38: Annual Reserve Margin



Eight Grid Alerts Issued in 2024

Key Observations:

- In 2024, eight Grid Alerts were declared, spanning all four quarters of the year.
  - Three Grid Alerts were declared in 2023, and seven in 2022.
- On April 5, one Grid Alert included a brief load shed event, the first since 2013.
- Another Grid Alert on January 13 triggered Alberta's first-ever provincial Emergency Alert due to an electricity supply shortage. The notification alert was sent to devices across the province encouraging residents to reduce electricity use, successfully lowering demand and preventing further impacts to the grid.

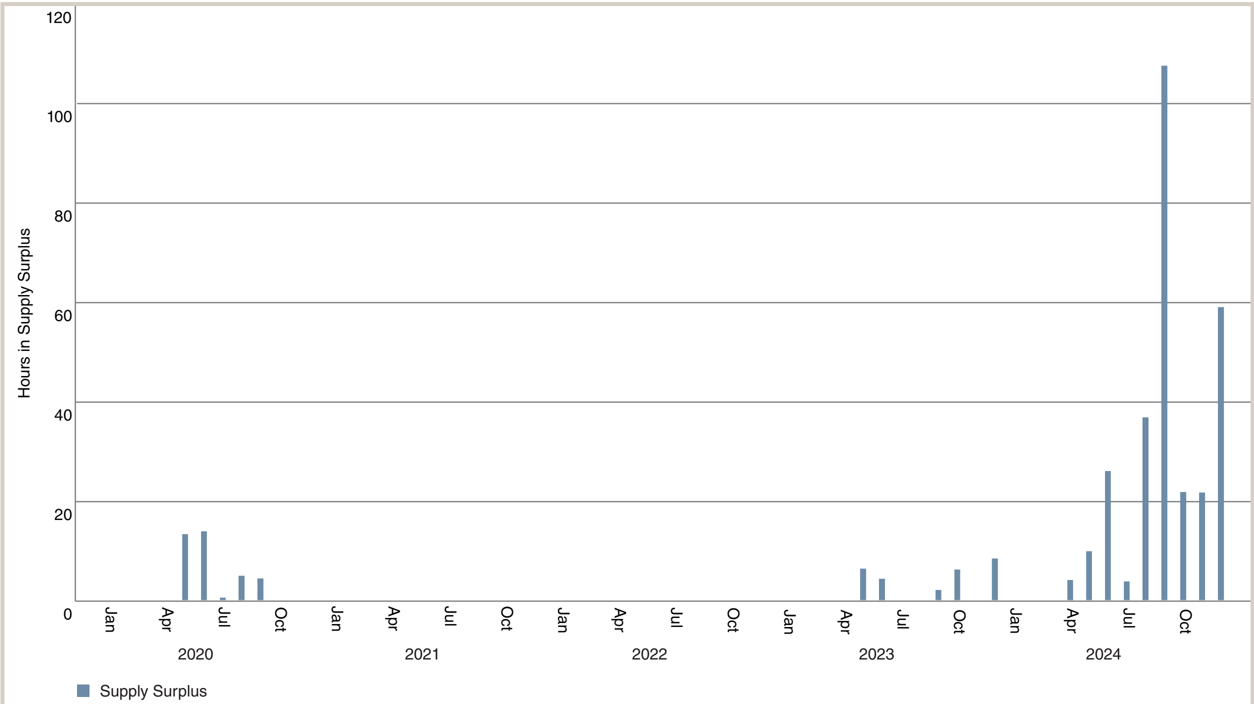
[10] In this calculation, the system generation capability excludes wind and solar generation, which may be unavailable, and reduces hydro generation to reflect seasonal variability. Generation capability reflects the installed capacity volumes at the end of the year.

TABLE 9: 2024 Grid Alerts

Date of Grid Alert	Time of Grid Alert	Contributing Factors	Impacts
January 2024			
Jan. 12, 2024	16:15-21:12	■ High load in extreme cold ■ Unplanned thermal outages ■ Low renewable generation ■ Supply shortages in neighbouring regions significantly reducing import availability (Jan. 13-15)	■ Provincial Emergency Alert sent during Jan. 13 event resulting in voluntary load reduction ■ No load shed required
Jan. 13, 2024	15:30-20:40		
Jan. 14, 2024	15:42-22:12		
Jan. 15, 2024	8:00-9:05		
April 2024			
Apr. 3, 2024	19:26-20:40	■ Planned thermal outages ■ Unplanned thermal outages ■ Wind and solar generation well below forecast	■ Load shed of up to 250 MW for 27 minutes on Apr. 5
Apr. 5, 2024	6:49-11:00		
July 2024			
Jul. 8, 2024	20:25-21:34	■ Unplanned thermal outages ■ Low wind and solar generation ■ BC Hydro transmission maintenance partially reducing import capability	■ No load shed required
October 2024			
Oct. 22, 2024	7:15-8:22	■ Planned thermal outages ■ Planned SK intertie outage ■ Low wind and solar generation	■ No load shed required

Supply Surplus Events were called 76 times in 2024

FIGURE 39: Monthly Total Duration of Supply Surplus Events



Key Observations:

- Supply surplus events increased significantly in 2024, driven by new thermal and renewable supply.
- These events totaled 289 hours (up from 27 hours in 2023), or 3.3 per cent of the year.
- Most occurred in the latter half of the year as newly added capacity began to generate consistently.

Flexibility

The electric system includes two types of generation: dispatchable and intermittent. Dispatchable generation, including thermal, hydro and battery storage, can be controlled by operators. Intermittent generation, such as wind and solar, depends on environmental conditions.

The AESO's 2023 Reliability Requirements Roadmap (R3) assessed the system's ability to adapt to handle increasing amounts of intermittent generation, including the need to continuously balance supply and demand under different scenarios.

With increasing wind and solar integration, demand and intermittent generation fluctuations—known as net demand variability—are expected to grow. To manage this variability, the system will need additional balancing measures, like more regulating reserves or the use of intermittent generation power ramp up managament.

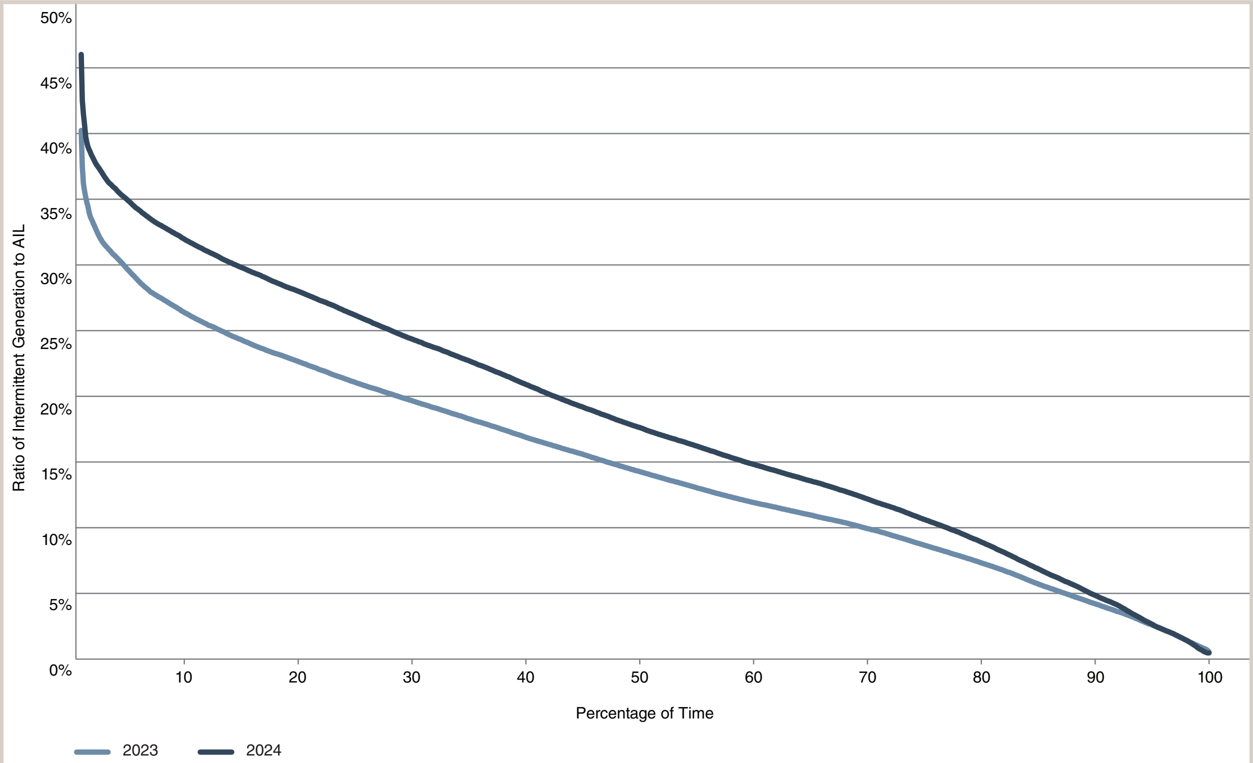
Historical data on market and system flexibility are covered in this section.

Intermittent Generation-to-AIL Ratio

Wind and solar now account for a larger share of total generation on the grid. This growth has increased the need for greater system flexibility to handle higher volumes of net-demand variability.

Figure 40 shows a duration curve of the ratio of intermittent generation to AIL in 2024.

FIGURE 40: Ratio of Intermittent Generation to AIL



Key Observations:

- The highest ratio of intermittent generation to AIL increased to 45.6 per cent, up from 39.8 in 2023.
- The median ratio increased to 17 per cent, up from 13.7 in 2023.
- For wind only, the median ratio of generation-to-AIL was 13.5 per cent (up from 10.7 in 2023), with a maximum of 41.7 per cent (up from 37.3 in 2023).
- For solar only, excluding overnight hours with no generation, the median ratio increased five per cent (up from 4.8 in 2023) and the maximum ratio was 15.7 per cent (up from 12.5 in 2023).

Net Demand Variability

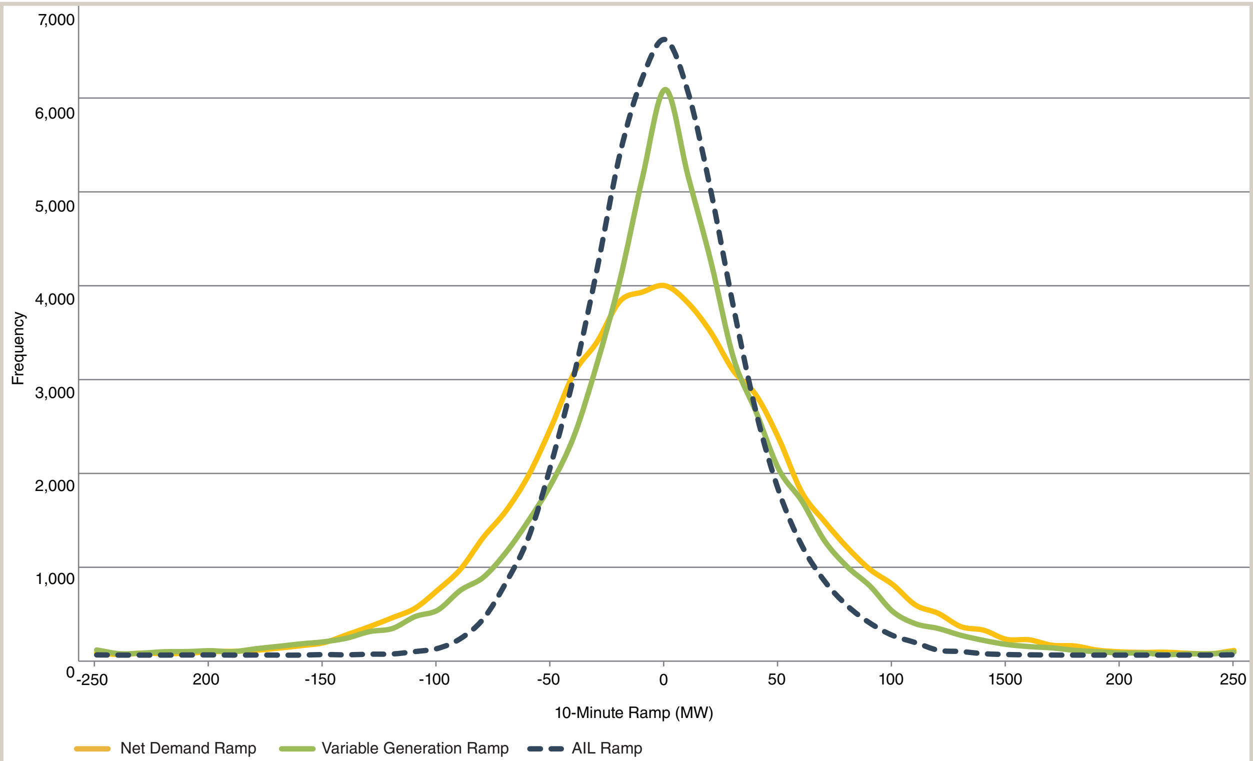
Net demand ramps show the change in AIL and intermittent generation over a set period. For example, during a 10-minute period, if AIL increases by 10 MW and intermittent generation drops by 10 MW, the net demand ramp is +20 MW, meaning dispatchable generation must cover the 20-MW gap.

The increasing size and frequency of net demand ramps, both up and down, is a result of increased intermittent wind and solar generation volumes. Dispatchable resources must be able to match the size, speed and frequency of the net demand ramps to reliably supply load customers.

Figure 41 shows the frequency and size of 10-minute ramps of intermittent generation, AIL, and net demand in 2024. Figure 42 shows the year-over-year differences in the frequency and size of the ramps.

These figures use data from every 10-minute period in the given year. Intermittent generation includes all five MW-or-larger wind and solar assets in Alberta. Small-scale wind and solar generators that produce less than five megawatts are generally connected to the distribution system and their variability is captured in AIL.

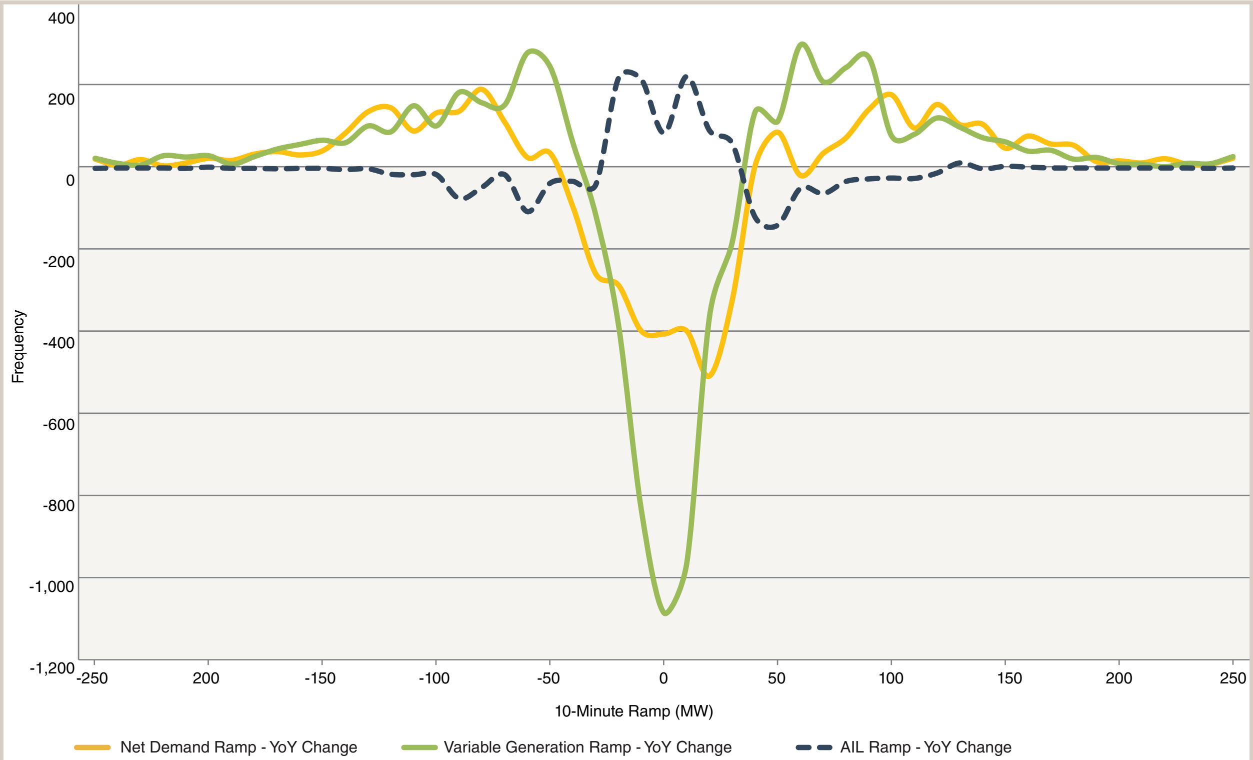
FIGURE 41: Distribution of 10-Minute Ramps for Wind and Solar Generation, Load, and Net Demand in 2024



Key Observations:

- Large ramps (+/-50 MW) made up 32 per cent of all net-demand ramps in 2024, up from 27 per cent in 2023.
- Large ramps (+/-50 MW over 10 minutes) are growing faster than predicted. The frequency in the R3 for the 2026 Reference Case was 27.8 per cent.
- The 2024 frequency (31.7 per cent) is almost the same as the Clean-Tech scenario from the 2026 forecast (31.8 per cent).
- This increase is mainly driven by wind generation.
- To handle this increased variability and to help maintain grid reliability, the AESO increased its regulating reserve procurement in late 2023.

FIGURE 42: Distribution of 2024 Year-Over-Year Change in 10-Minute Ramps for Wind and Solar Generation, Load, and Net Demand



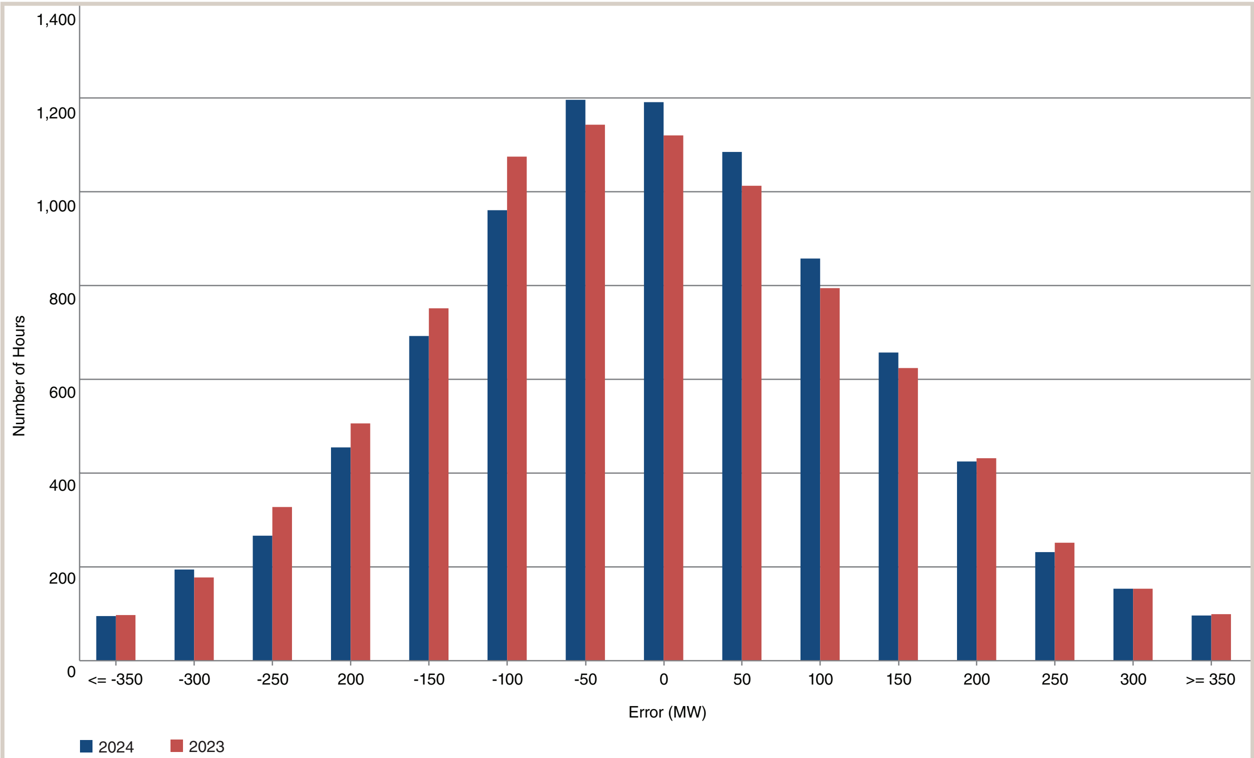
Forecast Uncertainty

AESO System Controllers ensure real-time energy requirements are met by dispatching energy through the energy market merit order. This involves making continual dispatch decisions to balance supply and demand as they fluctuate, despite not knowing how net demand will change in the next few minutes. Since demand forecasts and intermittent generation are not always precise, challenges can arise. Accurate short-term load and intermittent generation forecasting is key to helping the AESO effectively manage demand variability.

Short-Term Load Forecast Uncertainty

Figure 43 shows the distribution of the day-ahead load forecast error for all hours in 2024 compared to 2023. The error is calculated as the AIL day ahead forecast minus the actual AIL for a given hour.

FIGURE 43: Distribution of Day Ahead Load Forecast in 2024 and 2023



Key Observations:

- The median absolute per cent error (APE) was 0.99 per cent, an improvement from 1.05 in 2023.
- The 95th percentile of median APE was 3.17 per cent (down from 3.26 per cent), equivalent to approximately +/- 300 MW.
- Most forecast errors in the day ahead forecast are linked to changes in the weather forecasts.

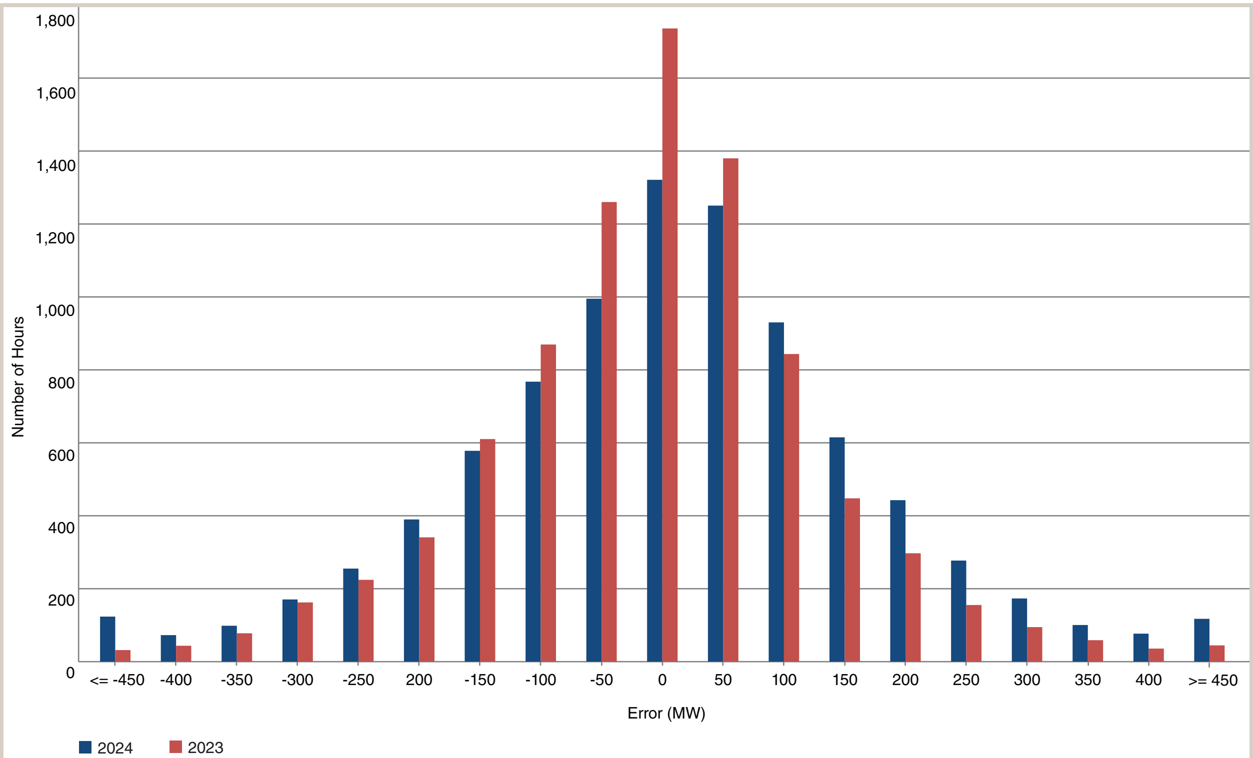
Wind Power Forecast Uncertainty

The AESO uses meteorological data to forecast wind and solar power supply for Alberta on both a seven-day-ahead (long-term) and a 12-hour-ahead (short-term) basis. Long-term forecasts update every six hours, while short-term forecasts update every 10 minutes.

Figure 44 shows the wind forecast error distribution for 2023 and 2024.

The wind generation forecast error for a given hour is the difference between the hour-ahead forecasted output volume and the actual output volume.

FIGURE 44: Distribution of Hour-Ahead Wind Power Forecast Error in 2024 and 2023



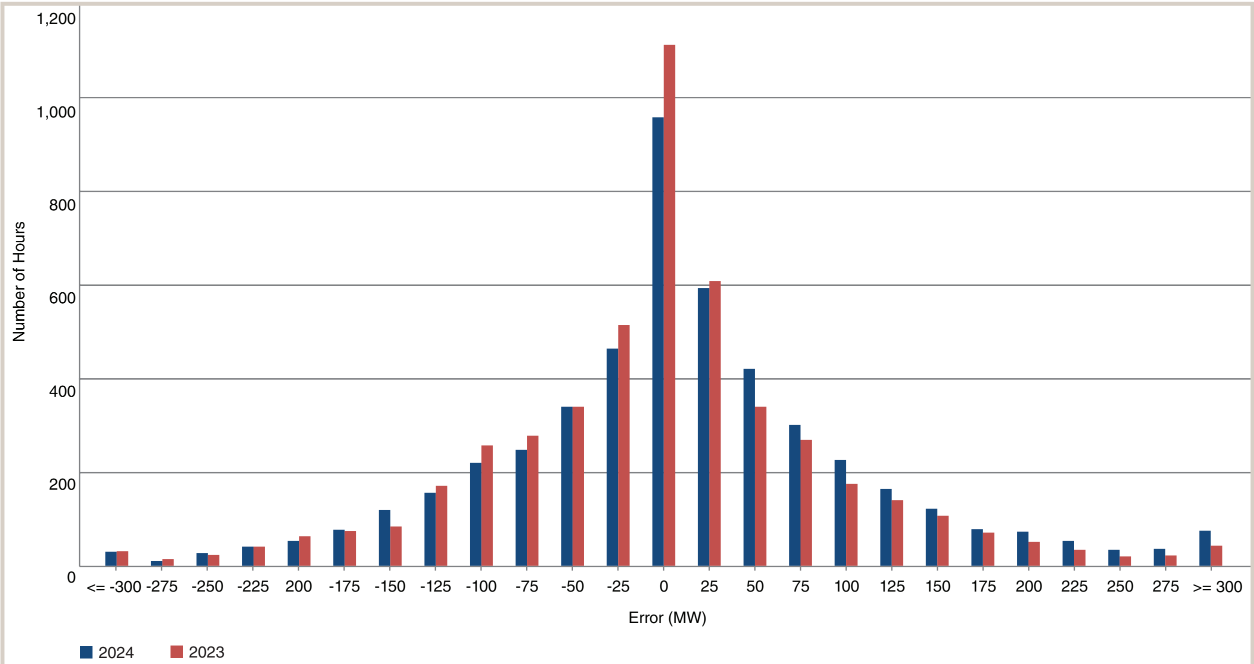
Key Observations:

- The median wind forecast error increased to 97 MW in 2024, up from 75 MW in 2023.
- This error equaled 2.7 per cent of commissioned wind capacity in both 2023 and 2024.
- As more wind capacity is installed, the forecast error, as a percentage of capacity, is expected to stay the same or improve. However, the absolute forecast error volume will increase in proportion to the increased capacity.
- Forecast errors are often skewed toward over-forecasted wind generation due to unpredicted curtailments, such as supply surplus events or transmission constraints, inflating the overall error.

Solar Power Forecast Uncertainty

Figure 45 shows the solar forecast error distribution for 2023 and 2024, excluding non-daylight hours where generation was zero.

FIGURE 45: Distribution of Hour-Ahead Solar Forecast Error in 2024 and 2023



Key Observations:

- The median forecast error increased to 51 MW in 2024, up from 45 MW in 2023.
- As a percentage of commissioned solar capacity, the median error was 3.9 per cent in 2024, down from 4.6 per cent in 2023.
- With more solar capacity installed, raw forecast errors are expected to increase, but percentage errors should stay the same or improve.
- Like wind, forecasts error tends to overestimate solar generation due to curtailments not reflected in forecasts.

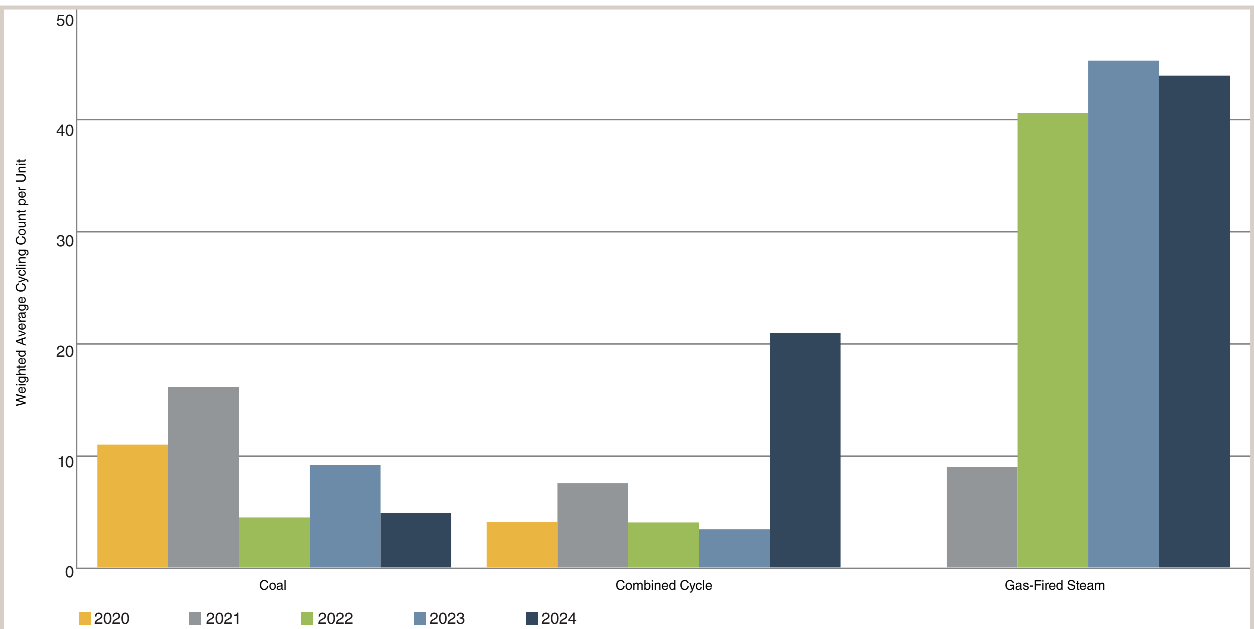
Unit On/Off Cycling

Figure 46 shows the average number of on/off cycles[11] for baseload generating units, weighted by maximum capability, over the past five years.

Several factors impact the number of on/off cycles of individual units, including economic drivers like natural gas prices and carbon costs, as well as planned and forced outages of the units or related transmission facilities connected to the generating unit.

- By 2022, most coal units had converted to other fuel types including gas-fired steam, with primarily baseload units left behind.
- Due to their high operating costs, gas-fired steam assets are often taken offline during periods of high supply.
- The rise in combined-cycle cycling in 2024 is primarily due to the testing behavior of newly commissioned assets and is expected normalize to previous levels in 2025.

FIGURE 46: Average Number of On/Off Cycles Per Generating Unit, by Technology and Year



[11] 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.

Ancillary Services

Cost of Operating Reserves Decreased

Operating reserves (OR) help manage real-time fluctuations in supply or demand on the Alberta Interconnected Electric System (AIES), ensuring the system has adequate supply to respond to supply contingencies. OR consists of two products:

- Regulating Reserve (RR): Uses automatic generation control to balance supply and demand in real time.
- Contingency Reserve (CR): Ensures supply and demand remained balanced during unexpected system events. CR is further divided into:
  - Spinning Reserve: Connected and synchronized to the grid.
  - Supplemental Reserve: Not synchronized with the grid.

Table 10 summarizes the total cost of OR over the past five years.

TABLE 10: Annual Operating Reserve Statistics

Year	2020	2021	2022	2023	2024
Volume (GWh)					
Active procured	5,561	5,624	5,719	5,360	5,834
Standby procured	1,940	1,191	994	954	713
Standby activated	348	156	179	215	87
Cost ($-millions)					
Active procured	$122	$314	$466	$334	$255
Standby procured	$3	$4	$2	$4	$10
Standby activated	$23	$20	$33	$41	$6
Total ($-millions)	**$148**	**$339**	**$501**	**$378**	**$271**

Key Observations:

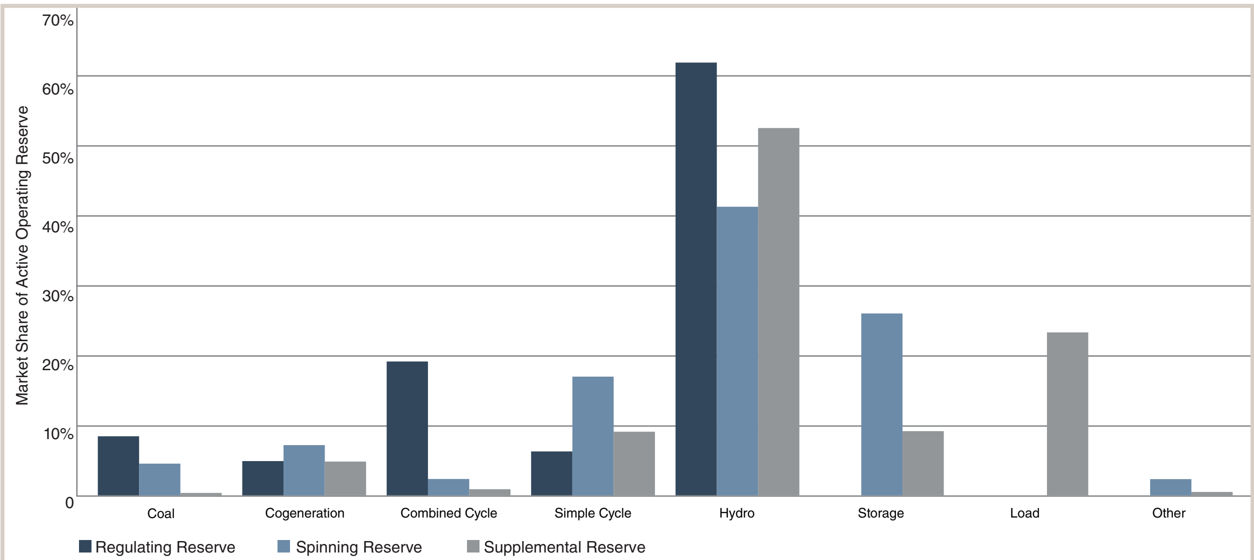
- OR costs dropped by 28 per cent in 2024 compared to 2023, marking the second consecutive year of declining costs.
- A 53 per cent drop in pool prices was a key driver for lower OR costs.
- On-peak regulating reserve (RR) volumes increased from 170 MW to 210 MW in early October 2023, contributing to a nine per cent increase in procured OR volumes (474 GWh). This increase was implemented to support higher net demand variability.
- Active RR volume increases led to a 25 per cent reduction in standby RR procured (713 GWh) and a 60 per cent decrease in standby RR activations (87 GWh), contributing to lower standby OR costs.

- Changes in OR market pricing also affected standby OR costs. Adjustments in the standby market's activation price calculations reduced the selection of offers with higher activation prices.
  - As a result, standby reserve procurement costs rose from $4 million in 2023 to $10 million in 2024, but activation costs dropped sharply from $41 million to $6 million.

Market share represents the percentage of total procured OR capacity provided by each technology of generation.

Figure 47 shows the annual market share of active OR by fuel type in 2024.

FIGURE 47: 2024 Market Share of Active Operating Reserve

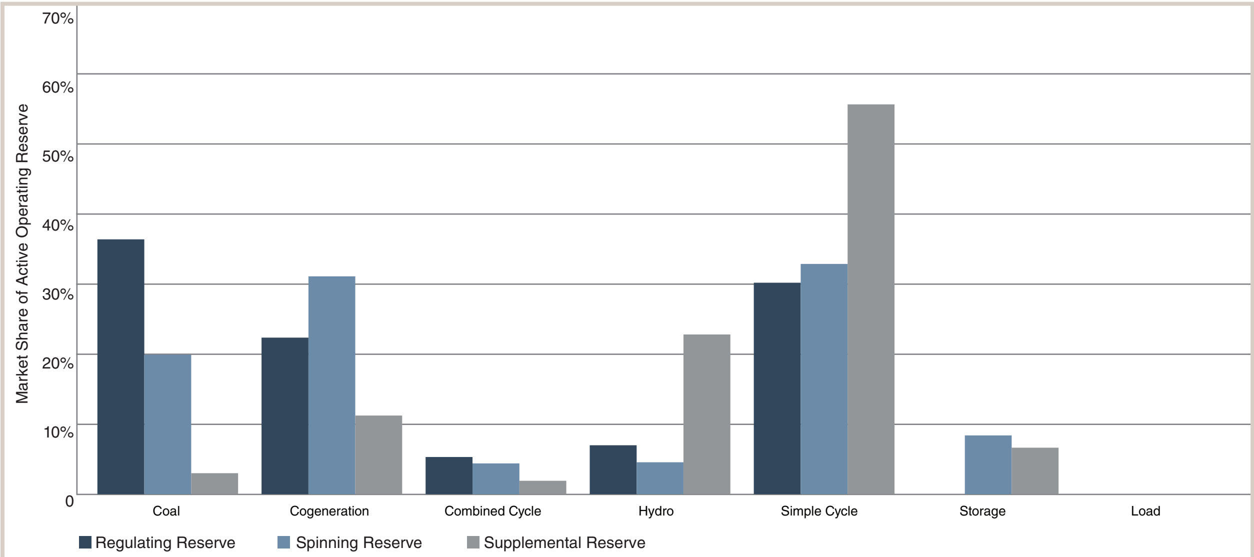


Key Observations:

- Hydroelectric generation had the largest market share in the regulating (61 per cent) and spinning (41 per cent) reserves.
- Storage assets provided 26 per cent of spinning reserves, down from 33 per cent in 2023.
- Hydroelectric generation also had the largest market share of supplemental product at 52 per cent, followed by load at 23 per cent.

Figure 48 shows the annual market share in the standby OR market by fuel type. Dual-fuel assets are included with coal, while gas-fired steam assets are included with simple-cycle assets.

FIGURE 48: 2024 Market Share of Standby Operating Reserve



Key Observations:

- Market share within standby regulating reserves is distributed more evenly, with coal at 36 per cent and Simple Cycle at 30 per cent.
- Simple Cycle dominates the standby spinning reserve market with 32 per cent, followed by cogeneration at 31 per cent.
- For standby supplemental reserves, Simple Cycle holds the largest share at 55 per cent, followed by hydro at 23 per cent.

Transmission Must-Run, Transmission Constraint Rebalancing, and Dispatch Down Service

AESO System Controllers issue transmission-must-run (TMR) dispatches to ensure system reliability when regional transmission capacity cannot provide enough imports to support local demand. TMR dispatches direct generators in or near the affected area to operate out-of-merit at a specified generation level.

- In 2024, 82 GWh of TMR energy was dispatched, costing $6.2 million.
- June and September accounted for a significant share of TMR dispatches, with 16 GWh and 23 GWh dispatched.

When in-merit energy is curtailed due to constraints and replaced with higher-cost generation, the affected generators qualify for Transmission Constraint Rebalancing (TCR) payments.

- Constraints in 2024 led to the curtailment of 409 GWh of in-merit energy.
- Despite the higher volume of curtailed energy, TCR payments to market participants fell by 28 per cent from 2023 levels, to approximately $3.8 million, driven by lower pool prices.

Table 11 summarizes the annual TMR, TCR and Dispatch Down Service (DDS) statistics over the past five years. TMR and TCR combined represent the total annual cost of Transmission Constraint Management (TCM).[12]

TABLE 11: Annual TMR and DDS Statistics

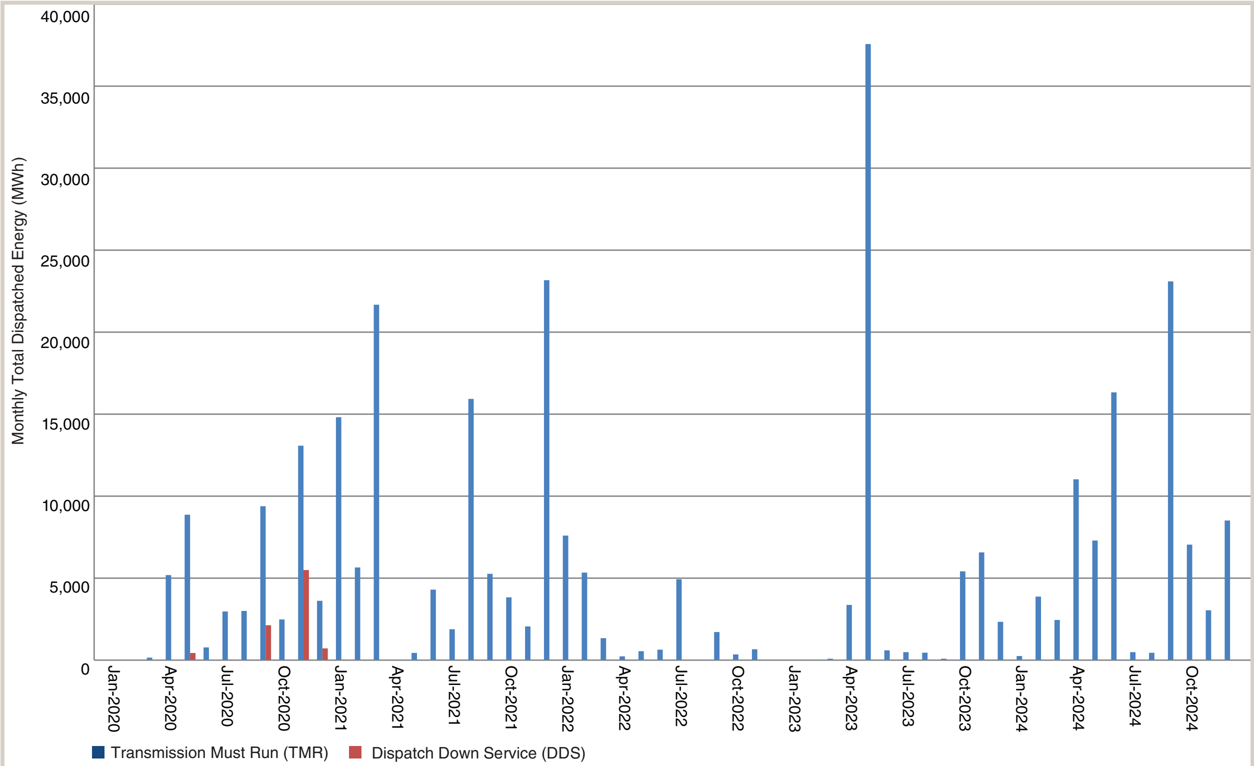
Year	2020	2021	2022	2023	2024[13]
Transmission Must-run					
Dispatched energy (GWh)	48	96	23	55	82
Contracted TMR costs ($ millions)	$0.67	$0.01	$0.02	$0.12	$0.46
Conscripted TMR costs ($ millions)	$1.93	$5.69	$2.51	$3.47	$5.74
Transmission Constraint Rebalancing					
Constrained-down generation (GWh)	73	69	89	305	409
Number of days with TCR payment	67	89	207	291	292
Total TCR payments ($-millions)	$0.52	$2.65	$1.80	$5.37	$3.84
Total Annual TCM Costs					
Annual TCM cost ($ millions)	$3.12	$8.35	$4.33	$8.97	$10.04
Dispatch Down Service					
Total payments ($-millions)	$0.16	$0	$0	$0	$0
Dispatched energy (MWh)	8,492	11	0	0	0
Average charge ($/MWh)	$18.84	$19.58	$0	$0	$0

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

[13] Preliminary data.

Figure 49 shows the monthly volumes of TMR and DDS dispatched over the past five years. AESO System Controllers issue TMR dispatches in response to transmission constraints on the AIES.

FIGURE 49: Monthly TMR and DDS Dispatched Energy



Payments to Suppliers on the Margin

Payments to Suppliers on the Margin (PSM) compensate generators when their dispatched offer blocks are priced higher than the settled pool price, covering the gap between dispatch and settlement intervals.

Table 12 summarizes the cost of PSM payments over the past five years.

TABLE 12: Annual Uplift Payments

Year	2020	2021	2022	2023	2024
Payments to Suppliers on the Margin					
Average range ($/MWh)	$5.89	$24.99	$38.08	$48.18	$21.06
Total PSM payments ($-millions)	$0.75	$2.89	$4.57	$5.89	$2.01

- The total cost of PSM was $2.01 million in 2024, down from $5.89 million in 2023.
- The annual average price range decreased 56 per cent to $21.06 MWh in 2024, influenced by the 53 per cent decline in pool price.

Glossary

- **Achieved Premium-to-Pool Price:** 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.
- **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. The achieved margin represents the difference between the achieved price and the average pool price over the year.
- **Active Reserve:** An operating reserve that is deployed immediately to maintain system reliability under normal conditions. It is procured day-ahead, with offers submitted as an index to the pool price. The AESO procures Active Reserve in ascending order of offer price, setting the clearing price as the sum of the equilibrium price (average of the marginal offer and bid ceiling) and the hourly pool price.
- **Alberta Internal Load (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 page and it is the main load measure used by the AESO to denote total load within the province.
- **Availability Factor:** 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 capacity to the installed generation capacity.
- **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 neighboring 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.
- **Behind-the-Fence (BTF) Load:** Load that is self-supplied and does not rely on the bulk transmission system. It 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. For the purposes of BTF calculations in this document, only load self-supplied by large generators (i.e., greater than five MW) is captured, thus is almost all industrial load.
  - Gross load on distribution facility owner (DFO) transmission networks is not readily available to the AESO, only the net metered load.
- **Capacity factor:** Represents the percentage of installed capacity used to generate electricity that was delivered to the grid. Capacity factor is calculated as the ratio of average generation to the maximum capability over the given year. It is calculated using total generation (not net-to-grid generation) of all assets with an installed capacity of greater than five MW and does not include smaller, distributed generation.
- **Cogeneration:** A gas-fired generation capacity type that produces electricity concurrently with heat needed for industrial processes.

- **Combined Cycle:** A gas-fired generation capacity type. A combined cycle asset contains one or more gas turbines with waste heat being used to power a steam turbine.
- **Dispatch Down Service (DDS):** A voluntary service designed to counteract the downward price impact of TMR dispatches. 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.
- **Dual Fuel:** Refers to assets that is able to use both coal and natural gas as fuel sources.
- **Gas-Fired Steam:** A gas-fired generation type consisting of former coal generators that were converted to use natural gas rather than coal as a fuel source for a steam turbine.
- **Grid Alert:** Occurs when the supply cushion is zero and emergency action is required to ensure system stability. The AESO must declare a Grid Alert if it is unable to meet minimum contingency reserve requirements as some or all the needed reserve capacity is used to serve load instead.
- **Intermittent Renewable Energy Sources (IRES) or Intermittent Generation:** Renewable generation that is not dispatchable due to changing weather conditions, such as wind and solar generation.
- **Inverter-Based Resource (IBR):** A source of electricity that is asynchronously connected to the grid via an inverter. This includes wind and solar assets, as well as battery storage.
- **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.
- **On-Peak and Off-Peak:** Each day is separated into on-peak and off-peak periods: on-peak periods start at 7:00 a.m. and end at 11:00 p.m. daily; the remaining hours of the day make up the off-peak period.
- **On/off cycle average - Methodology for calculating:** The number of on/off cycles for each unit was counted for each year from 2020 to 2024. Then, 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.
- **Operating Reserve (OR):** A service used to manage real-time fluctuations in supply and demand, ensuring the system has sufficient supply to respond to contingencies. OR is divided into:
  - **Regulating Reserve (RR):** Uses automatic generation control to continuously match supply and demand in real-time.
  - **Contingency Reserve (CR):** Maintains the balance of supply and demand when an unexpected system event occurs.
    - **Spinning Reserve:** Synchronized to the grid and ready to respond immediately. Alberta reliability standards require spinning reserves to provide at least half of the total contingency reserve.
    - **Supplemental Reserve:** Available but not required for synchronizing.
- **Other fuel types** contain thermal assets with fuel sources such as biomass, waste heat, or geothermal energy, often in combination with natural gas.

- **Payments to suppliers on the margin (PSM):** Otherwise known as uplift payments, follow from 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 the System Controller dispatches 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. Hourly PSM is determined by the difference between the maximum SMP in a settlement period and the pool price.
- **Pool Price:** The simple average of the 60 system marginal prices in the one-hour settlement interval. All energy generated in the hour and delivered to the AIES receives a uniform clearing price—the pool price—regardless of its offer price. System load draws energy from the grid and pays the uniform clearing price.
  - The 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.
- **Renewable Generation:** Defined to include wind, solar, and hydro generation.
- **Reserve Margin:** Represents the amount of firm generation capacity more than the annual system peak load expressed as a percentage of the system peak load. Firm generation is defined as installed and future generation capacity, adjusting for seasonal hydro capacity and behind-the-fence demand and generation, and excludes wind and solar capacity.
- **Simple Cycle:** A gas-fired generation capacity type including gas turbines and reciprocating engines. These differ from combined cycle assets in that they do not recover waste heat. They are generally smaller and more flexible but less efficient than combined cycle assets.
- **Spark Spread:** A high-level estimate of the profitability of operating a generic combined-cycle natural gas baseload generation asset, with a heat-rate (HR) of 7.5 GJ/MWh, in the energy market.
- **Standby Reserve:** An additional reserve procured to be available if active reserve is insufficient. It is dispatched when required or if active reserve cannot be provided due to outages or transmission constraints. It operates with two price components: the premium price, paid for availability, and the activation price, paid if dispatched. The standby market clears based on a blended price formula that takes into consideration the premium and activation price offered by each potential supplier.
- **Supply Cushion:** Represents the amount of unused but available capacity remaining in the merit order at a given moment. If the supply cushion reaches zero, a Grid Alert may be called if additional resources are needed (such as the use of contingency reserves) to balance supply and demand.
- **Supply Surplus Event:** Occurs when the amount of generation offered into the market at a price of zero dollars exceeds the amount needed to meet demand. The AESO takes actions such as curtailing import volumes and zero-dollar generation to respond to these circumstances.
- **System Load:** Represents the total electric energy billed to transmission consumers in Alberta and Fort Nelson, British Columbia (B.C.), plus transmission losses. System load is roughly comprised of half residential plus commercial loads and half industrial loads.
- **System-Load-to-AIL-Ratio:** Describes how much of total load in Alberta is using the bulk transmission system. 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.
- **Total Transfer Capability (TTC) rating:** 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.

- **Transmission Constraint Rebalancing (TCR):** Represents a mechanism to compensate generators when system constraints force a change in the merit order, affecting their dispatch position. 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.
- **Transmission Must-Run (TMR):** A service where generators in constrained regions are directed to operate out of merit to maintain system reliability when transmission capacity is insufficient to support local demand.

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03/24