MARKET
SURVEILLANCE
ADMINISTRATOR

Quarterly Report for Q1 2023

June 2, 2023

Taking action to promote effective competition and a culture of compliance and accountability in Alberta's electricity and retail natural gas markets

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TABLE OF CONTENTS

THE QUARTER AT A GLANCE

- The average pool price in Q1 2023 was $142.00/MWh, a 58% increase relative to Q1 2022 despite mild weather, lower natural gas prices, and increased solar generation. The average pool price increased year-over-year because of higher offer prices on some generation assets, lower import volumes, and more thermal outages.

- The volume of wind and solar generation increased to record levels in Q1 2023, and their supply is expected to increase further as new assets enter service. In March, pool prices were higher during the morning, when demand ramped upward and solar generation was low, and during the evening, when demand was still high and solar generation declined. Prices were lowest during mid-day hours rather than overnight because of increased solar supply. Higher wind and solar generation are causing significant changes in net demand, which increases uncertainty around unit commitment and raises the need for ramping capability. The MSA believes that changes to the market rules and/or design are needed to address these issues.

- The ability of companies to exercise market power was lower in Q1 2023 relative to Q3 2022 and Q4 2022, in part because of mild temperatures and increased wind and solar generation. Some larger suppliers continued to exercise market power in Q1 2023. One supplier withheld a large amount of capacity by pricing it above $900/MWh regardless of market conditions. Another supplier generally offered large amounts of capacity between $700 and $900/MWh when market conditions were tighter.

- The total volume of forward trades in Q1 2023 was 6% lower than in Q1 2022. Realized pool prices in January and February were below forward market expectations, partly because of mild weather. The expected average pool price for 2023 fell by 20% over the quarter to $145/MWh. Long-term forward prices indicate that expectations are for lower pool prices in the years ahead. For example, in late March a trade covering 2024 through 2030 was priced at $77.35/MWh.

- The *Regulated Rate Option Stability Act* (RROSA) passed by the Alberta legislature placed a ceiling on regulated electricity rates at 13.5 cents/kWh for January, February, and March 2023. Fixed competitive rates for electricity increased over Q1, despite the decline in near-and-long term forward prices. Variable competitive rates were generally lower in Q1 relative to Q4 reflecting lower pool prices. RRO customers continued to have strong incentives to switch to competitive fixed electricity rates given the RRO rate expectations for the April 2023 to March 2024 period.

- From January 1 to March 31, 2023, the MSA closed 58 ISO rules compliance matters; 22 matters were addressed with notices of specified penalty. For the same period, the MSA closed 25 Alberta Reliability Standards Operations and Planning compliance matters; eight matters were addressed with notices of specified penalty. In addition, the MSA closed 42 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; four matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Quarterly summary

The average pool price in Q1 was $142.00/MWh, a 58% increase compared to Q1 2022. Higher pool prices year-over-year were due to more thermal outages, lower net imports, and higher offer prices on some generation assets. These factors offset lower natural gas prices and increased solar generation (Table 1).

Table 1: Summary market statistics for Q1 2023 and Q1 2022

		2023	2022	Change
Pool price (Avg $/MWh)	Jan	$126.13	$90.81	39%
	Feb	$123.50	$105.22	17%
	Mar	$174.63	$75.38	132%
	Q1	**$142.00**	**$89.98**	**58%**
Demand (AIL) (Avg MW)	Jan	10,387	10,512	-1%
	Feb	10,458	10,417	0%
	Mar	10,226	10,070	2%
	Q1	**10,354**	**10,330**	**0%**
Gas price AB-NIT (2A) (Avg $/GJ)	Jan	$3.58	$4.18	-14%
	Feb	$2.64	$4.48	-41%
	Mar	$2.98	$4.83	-38%
	Q1	**$3.08**	**$4.50**	**-32%**
Wind generation (Avg MW)	Jan	1,227	1,085	13%
	Feb	1,375	1,011	36%
	Mar	789	919	-14%
	Q1	**1,122**	**1,005**	**12%**
Solar generation (Avg MW during peak hours)	Jan	133	40	230%
	Feb	213	59	259%
	Mar	453	126	259%
	Q1	**268**	**76**	**254%**
Net imports (+) Net exports (-) (Avg MW)	Jan	-256	471	-154%
	Feb	15	550	-97%
	Mar	221	615	-64%
	Q1	**-7**	**545**	**-101%**
Thermal outages (Avg MW)	Jan	2,022	1,766	14%
	Feb	1,699	1,494	14%
	Mar	2,110	1,698	24%
	Q1	**1,952**	**1,658**	**18%**

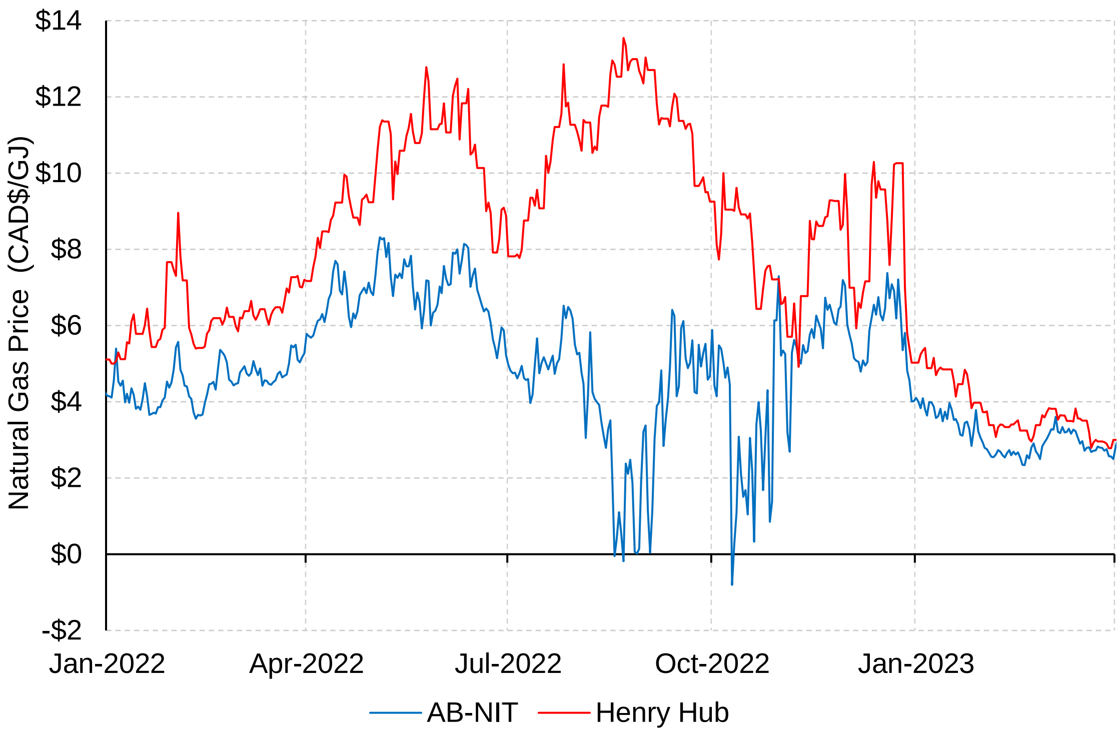
The average pool price in Q1 was 34% lower than in Q4 2022, which averaged $213.92/MWh. Prevailing weather conditions and offer behaviour were both factors in this outcome. Mild weather for much of January and February (Table 2) meant lower demand, higher wind generation, and lower natural gas prices relative to December.

Table 2: Monthly average temperatures across Calgary, Edmonton, and Fort McMurray (°C)

Month	2020/21	2021/22	2022/23
Dec	-5.3	-16.2	-15.5
Jan	-7.2	-11.1	-6.9
Feb	-15.2	-9.7	-9.1
Mar	-0.3	-2.9	-7.5

Mild weather across much of North America in early 2023 put downward pressure on natural gas prices. Figure 1 illustrates same-day natural gas prices in Alberta and at Henry Hub.[1] Natural gas prices fell in late December and declined further in early January (Figure 1). Alberta natural gas prices averaged $2.64/GJ in February, the lowest since March 2021. Natural gas prices are an important cost-driver for the Alberta power market; in Q1 natural gas generation assets set the marginal price 92% of the time.

Figure 1: Same-day natural gas prices in Alberta and Henry Hub (Jan. 1, 2022 to Mar. 31, 2023)



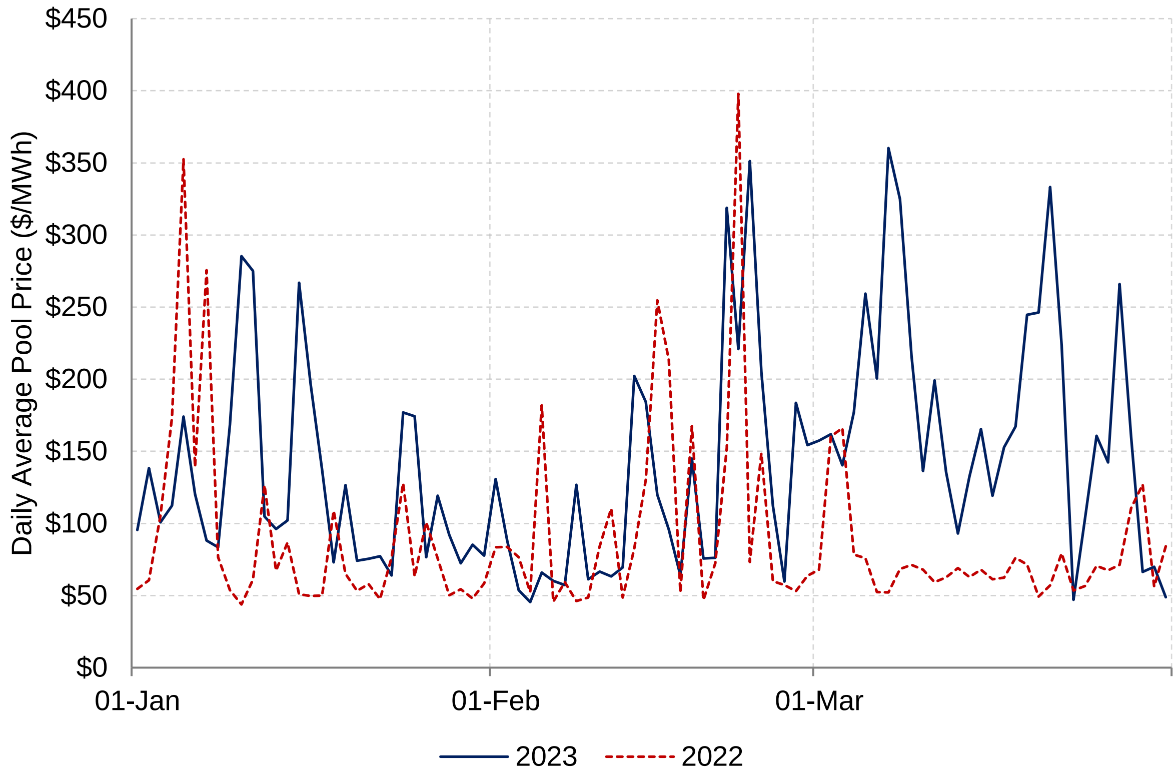
[1] Henry Hub is a large natural gas demand centre near the Gulf Coast in Louisiana. Alberta natural gas typically trades at a discount to prices at Henry Hub, reflecting pipeline constraints and transportation costs.

Despite lower natural gas prices, pool prices were higher year-over-year (Figure 2). March was the highest priced month in Q1 averaging $174.63/MWh. Thermal outages and less wind generation in March were both factors in the higher prices. In addition, there was a period of relatively low temperatures in early March which increased demand.

From March 1 to 8 the Shepard combined cycle asset (868 MW) was offline for operational reasons, and the asset was derated to around 50% of its capacity until March 23. In February, the Shepard asset generated an average of 812 MW, so this outage significantly reduced supply and put upward pressure on pool prices.

Thermal outages were 294 MW higher on average in Q1 compared to Q1 2022 (Table 1),[2] in part because of an on-going outage at the HR Milner natural gas asset (300 MW). HR Milner went offline in early September 2022 for a planned outage to transition the asset from simple cycle to combined cycle. The asset was originally scheduled to be back online in early November 2022, but the outage was extended due to operational issues.[3] At the time of publication, the HR Milner asset is expected to return in late August 2023.

Figure 2: Daily average pool prices in Q1 2023 and Q1 2022



[2] The outage figures reflect the difference between Maximum Capability and Available Capability. The SCL1 asset was not included because it has changed from net to gross reporting.

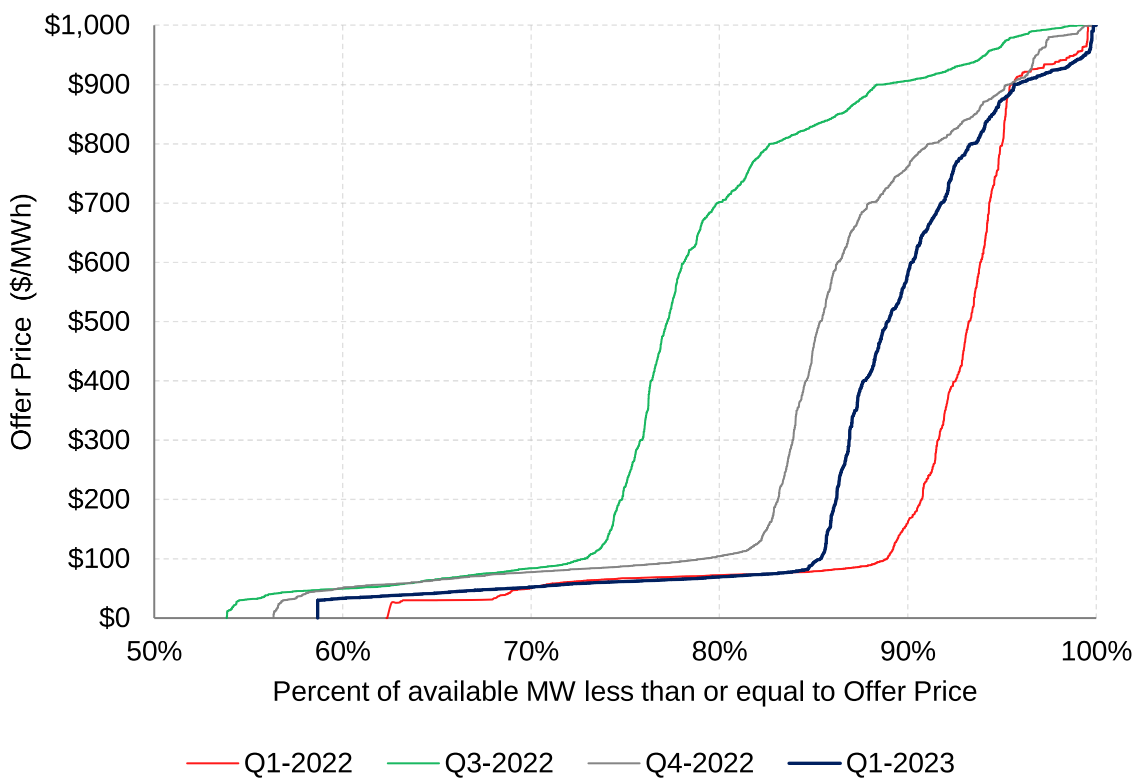
[3] Maxim Power – News Releases

Offer behaviour was another reason pool prices in Q1 were higher than in Q1 2022, and lower than in Q4 2022. Figure 3 illustrates duration curves of offer prices on coal and converted coal assets for select quarters. These assets include the thermal generating units at Battle River, Genesee, Keephills, Sheerness, and Sundance. In total, these assets represent around 3,900 MW of generation capacity and form a meaningful portion of the dispatchable capacity in Alberta.

Overall, offer prices on these assets were higher in Q1 compared to Q1 2022, as indicated by the leftward shift of the duration curve. For example, in Q1 8% of the available capacity on these assets was offered above $700/MWh, compared to 6% in Q1 2022.

The figure also illustrates that offer prices on these assets were lower in Q1 relative to Q3 2022 and Q4 2022 when 20% and 12% of the available capacity was offered above $700/MWh, respectively. Market power and offer behaviour are discussed in more detail in section 1.3.

Figure 3: Offer price duration curves for coal and converted coal assets



In Q1 the average net flow of power over Alberta's interties was 7 MW of exports, compared to 545 MW of imports in Q1 2022, an average supply reduction of 552 MW (Table 1). In January net exports averaged 256 MW, the highest average export volume since December 2018 (Figure 4).

The year-over-year reduction in imports and increase in exports occurred due to a change in relative price levels between Alberta and Mid-Columbia (Mid-C) (Table 3). In January 2023 imports into Alberta were economic in only 16% of hours (the Alberta pool price was more than $12/MWh higher than price in Mid-C) compared to 53% of hours in January 2022. In almost 80%

of hours in January 2023 prices in Mid-C were more than $12/MWh higher than pool price in Alberta, implying exports were economic. Year-over-year, each month in Q1 saw greater incentive for exports and lower incentive for imports.

Effective March 15, the AESO increased the required volume of Load Shed Service for Imports (LSSi).[4] LSSi is an ancillary service product that pays certain loads to arm their consumption, such that it will trip automatically in the event of a trip on the BC/MATL intertie, thereby reducing the net supply loss during a contingency event. The higher LSSi requirements mean that available capacity on the BC/MATL intertie has been reduced, lowering import supply, and putting upward pressure on pool prices in some hours. Imports and exports are discussed in additional detail in section 2.2.

Figure 4: Monthly average net imports (January 2018 to March 2023)

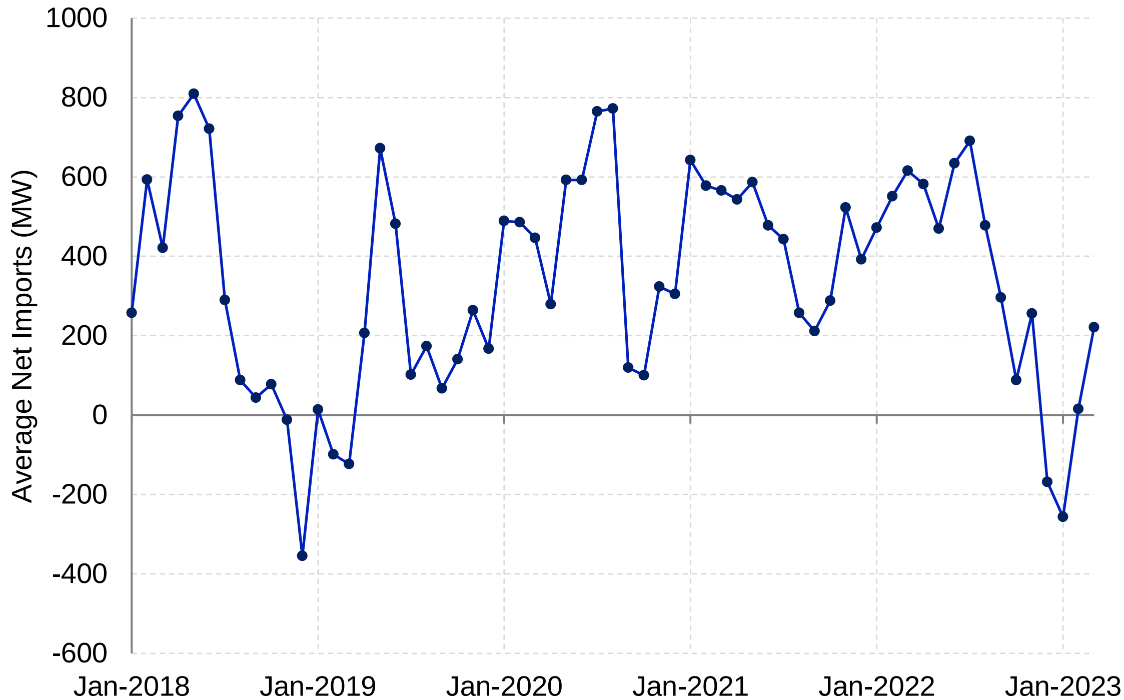


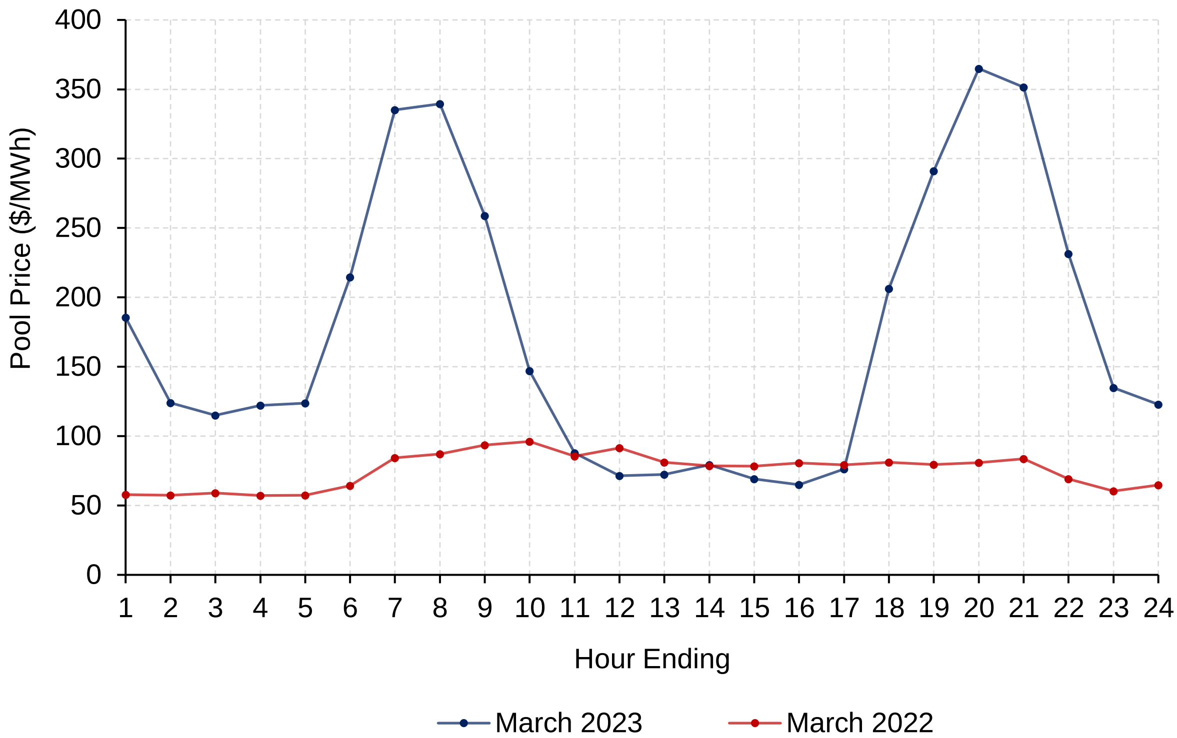
Table 3: Alberta pool prices relative to Mid-C prices

	Pool price > Mid-C + $12 (Import economic)		**Pool price < Mid-C - $12 (Export economic)**	
	2023	**2022**	**2023**	**2022**
Jan	16%	53%	79%	9%
Feb	30%	64%	52%	9%
Mar	39%	79%	48%	4%

[4] AESO Reliability Requirements Roadmap Report and Information Session

Average solar generation during peak hours (07:00 to 23:00) increased by 254% relative to Q1 2022, putting downward pressure on pool prices during daylight hours, as any increase in supply would do. Figure 5 illustrates average pool prices by hour-ending in March 2022 and March 2023. The daily shape of prices in March 2023 has a distinct two-peak shape, where the peaks coincide with (i) the morning ramp up in demand and (ii) high evening demand. In both periods solar generation was low. Due to supply from solar generation, pool prices during the middle of the day were lower than during the middle of the night. As investment in solar generation continues, this may become a standard feature of daily pool price variation in Alberta's wholesale electricity market.

Figure 5: Average daily shape of pool prices (March 2022 and March 2023)



1.2 Wind and solar growth

Driven by recent capacity additions, wind and solar generation reached historic highs in Q1. In February, monthly wind generation averaged 1,375 MW, and in March average solar generation during peak hours was 453 MW.

Although no new wind or solar assets entered service in Q1, three wind assets that were first listed on the AESO Current Supply Demand (CSD) Report in Q4 2022 began to deliver energy to the grid for the first time in Q1 2023.[5] Table 4 shows the 435 MW of wind assets that began

[5] When an asset delivers 1 MW or more in a given hour.

delivering energy in Q1, as well as a battery storage asset that entered service on January 16, 2023.

Table 4: Assets that entered service or began delivering energy in Q1 2023

Fuel type	Asset	Capacity (MW)	In-service date	First delivered energy date
Battery	eReserve5 Hughenden	20	Jan 16, 2023	April 3, 2023
Wind	Cypress 1	196	Nov 8, 2022	Jan 22, 2023
Wind	Garden Plain	130	Nov 21, 2022	Jan 23, 2023
Wind	Jenner 3	109	Nov 15, 2022	Jan 4, 2023

Similarly, solar assets commissioned towards the end of 2022 began generating larger volumes in Q1 as daylight increased from winter into spring. For example, at the end of September 2022, the Travers solar asset (465 MW) reached full commercial operation. Generation from this asset contributed to the increase of solar generation in Q1.

The AESO's May Long-Term Adequacy (LTA) Report lists projects currently under construction.[6] The report states that 1,646 MW of solar and 1,820 MW of wind capacity are currently under construction. Most of these projects are expected to enter service by the end of 2023, and all are expected to enter service by the end of 2024. As a result, facilities under construction represent an increase in solar capacity of 141%, or a factor of 2.4. Wind facilities under construction represent an increase in capacity of 50%, or a factor of 1.5.

Figure 6 and Figure *7* show monthly average generation and capacity for wind and solar respectively, as well as the hourly maximum generation observed in each month. The figures also show the expected increase in installed capacity resulting from adding projects that are currently under construction.[7]

[6] AESO: Long-term adequacy metrics - May 2023

[7] AESO: Long-term adequacy metrics - May 2023

Figure 6: Monthly average wind generation and capacity
(January 2020 to March 2023, and capacity under construction)

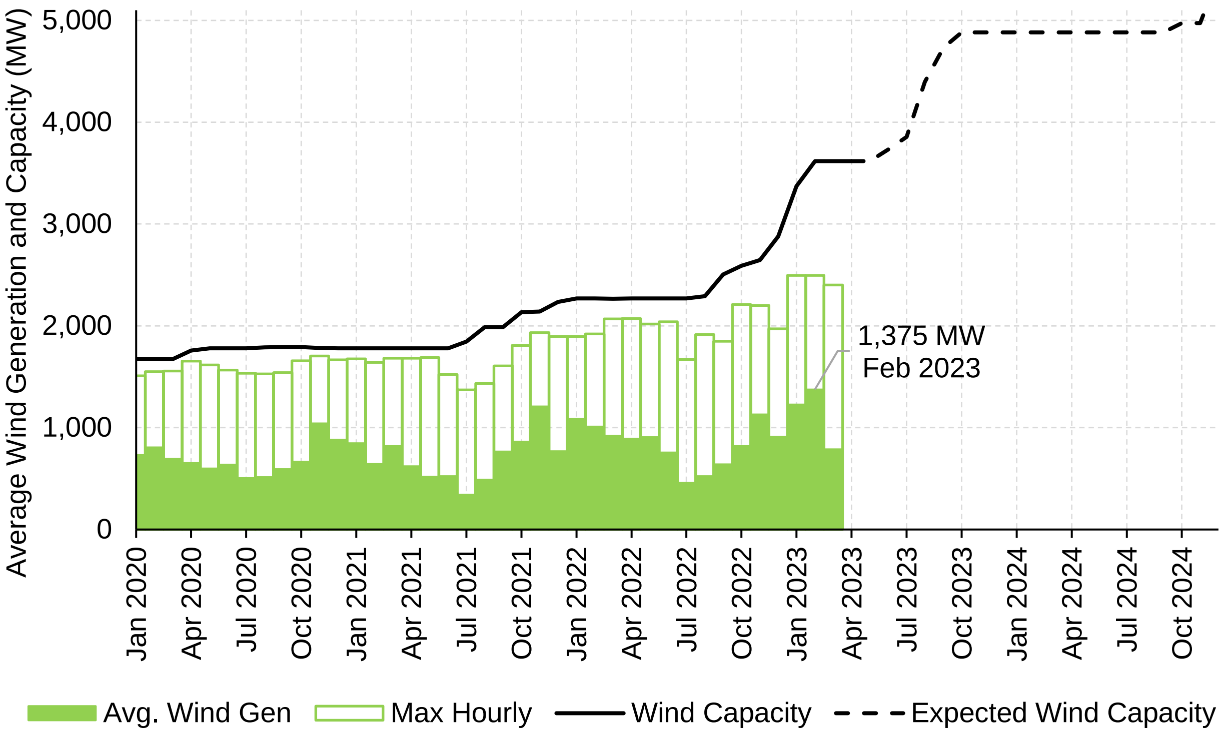
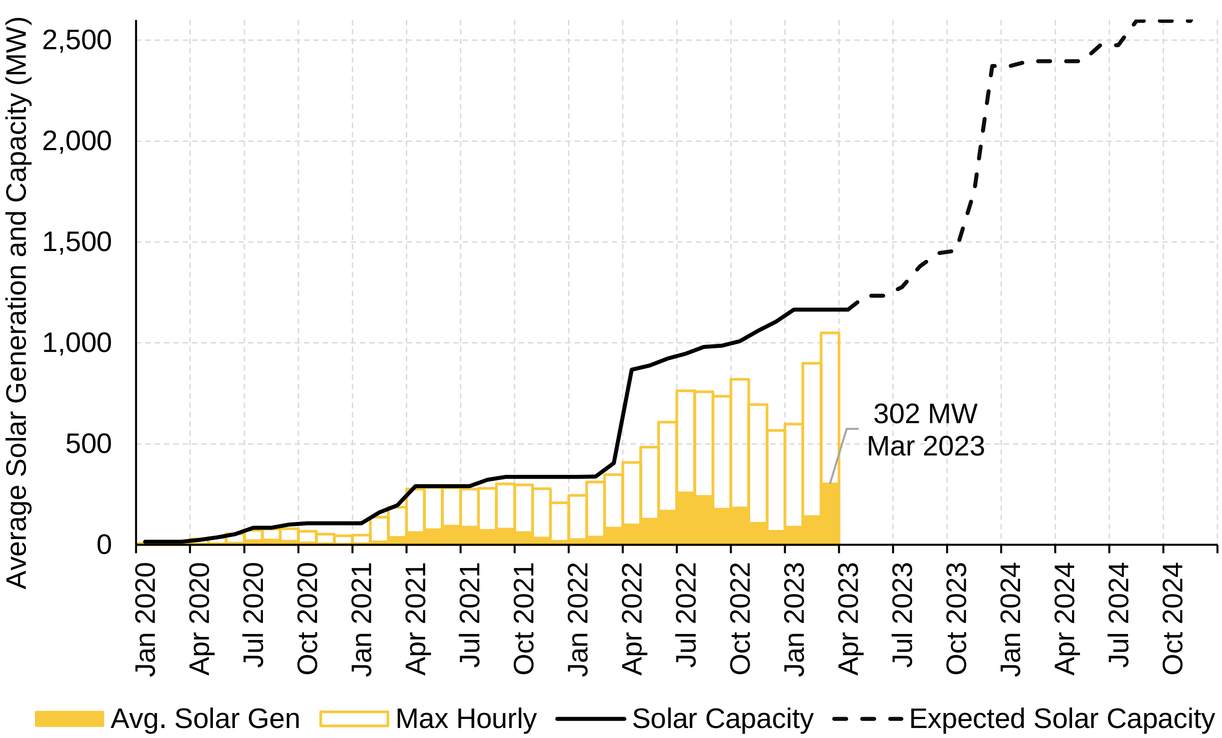
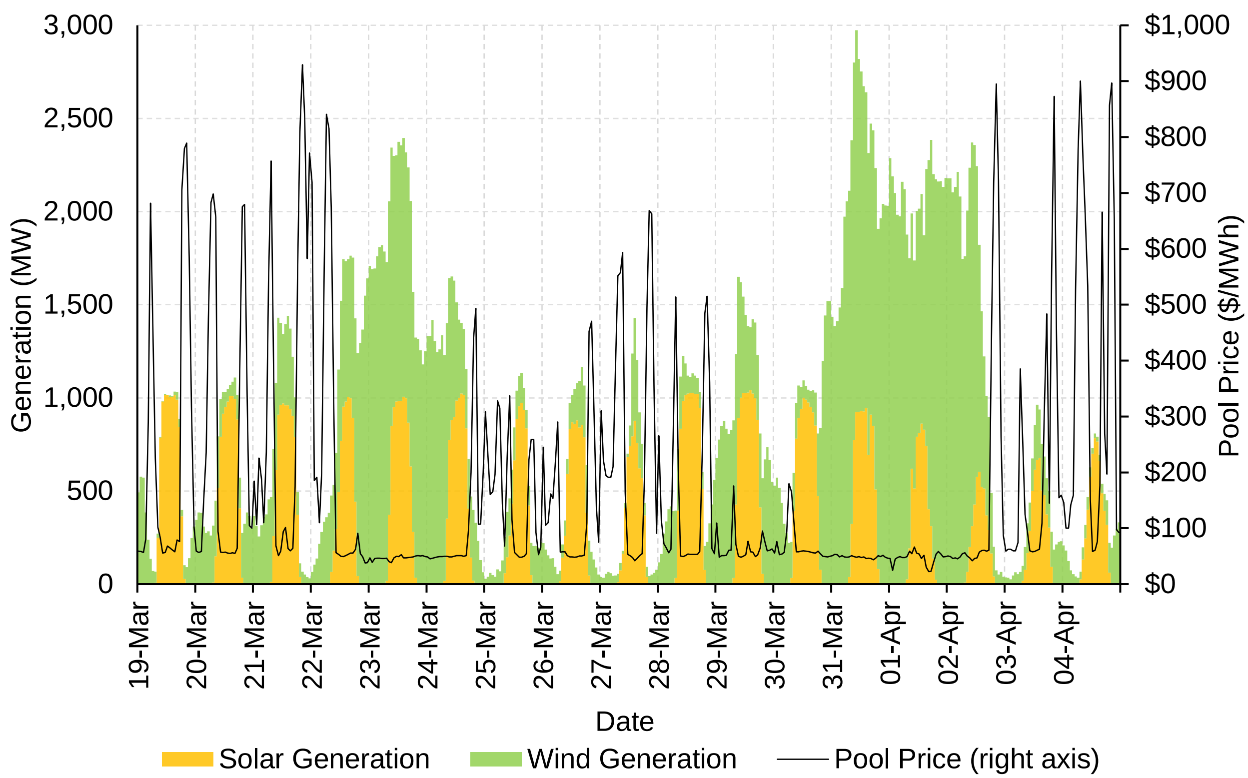


Figure 7: Monthly average solar generation and capacity
(January 2020 to March 2023, and capacity under construction)



As with other sources of supply, high renewable generation puts downward pressure on pool price. Even on days with low wind generation in Q1, when solar generation peaked around 1,000 MW in March, pool prices typically remained low during the daylight hours, and increased when the sun set (Figure 8).

Figure 8: Wind generation, solar generation, and pool prices (March 19 to April 4, 2023)



As illustrated in Figure 5 and Figure 8, mid-day solar generation contributed to lower mid-day pool prices. As a result, in recent months, the average solar received price has been lower than the average pool price. In Q1 2023 solar generation received an average discount of 37% compared to average pool price (Table 5). In Q1 2022 the solar received price averaged an 11% discount to pool price.

Table 5: The premium of solar and wind received prices relative to the average pool price

Month	Solar premium (% of avg pp)	Wind premium (% of avg pp)
Jan 2023	-16%	-23%
Feb 2023	-25%	-36%
Mar 2023	-52%	-30%
Q1 2023	**-37%**	**-32%**

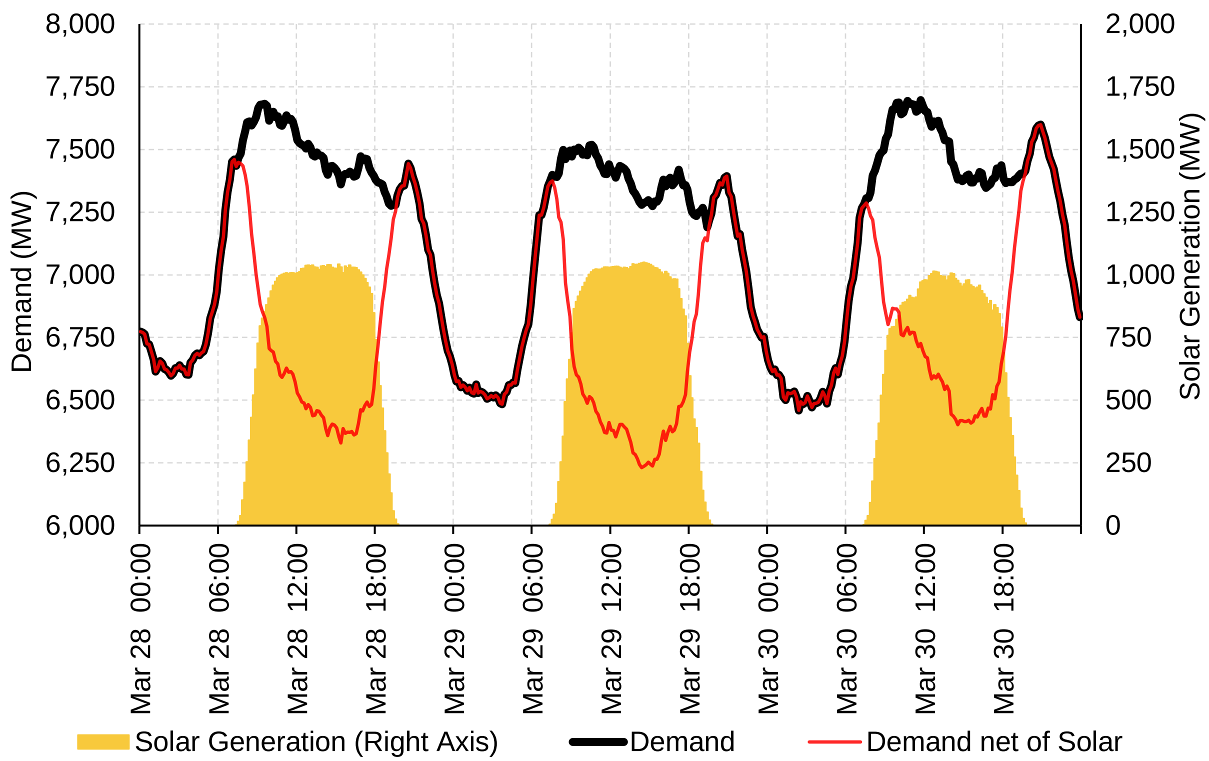
1.2.1 *Demand net of solar generation*

System load is a measure of electricity demand. System load measures the amount of electricity demand on the Alberta grid and does not include demand that is served by on-site generation. Electricity demand exhibits a typical daily shape that increases in the morning, peaks around HE 18, and then decreases into the night and early morning of the next day (Figure 9). In Q1 2023, the average difference between the maximum and minimum hourly system load in a day was about 1,200 MW.

Solar generation coincides with the daylight hours, and typically peaks in the afternoon. By the end of Q1 2023, there was 1,165 MW of installed solar capacity in Alberta. On sunny days, the change in solar generation exceeded the change in electricity demand, and demand net of solar generation reached its lowest point in the late afternoon (Figure 9). Hourly solar generation set a number of new record highs in March. On March 29 in HE15, solar generation reached a (then) new record of 1,049 MW.

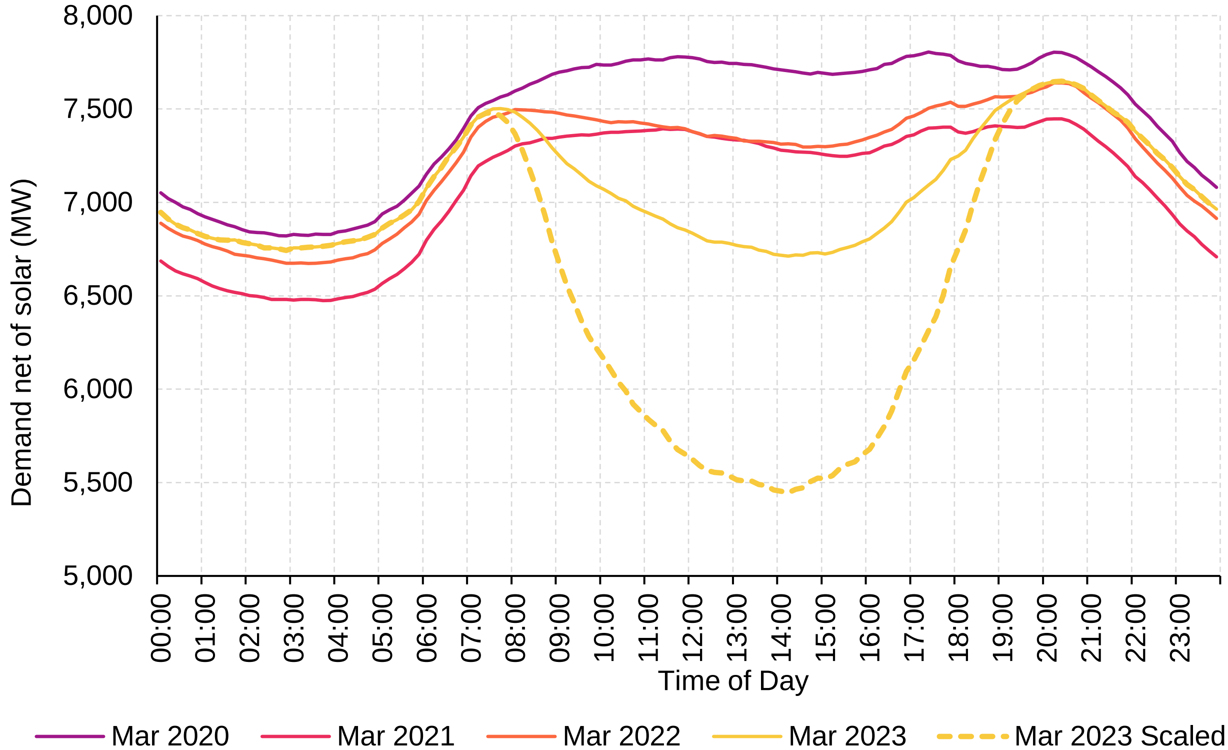
Demand net of solar is the amount demand that will have to be met by other generation types. Figure 9 illustrates demand net of solar for March 28 to 30. In the morning, demand net of solar followed demand up during the morning ramp and then declined as solar generation increased. During the day, demand net of solar was lower than overnight because of the high solar generation. In the evening, demand net of solar increased as the sun set but demand remained high, before declining overnight with the fall in demand. As shown, demand net of solar was lower in the afternoon than overnight.

Figure 9: Demand net of solar generation (March 28 to 30, 2023)



The daily dynamic of demand net of solar generation developed a distinct two-peaked shape that was more pronounced in the March 2023 profile than in March of prior years (Figure 10).

Figure 10: Average daily demand net of solar profiles
(March 2019 to 2023, and March 2023 scaled for capacity under construction)



To provide an indication of what demand net of solar will look like in the near future, Figure 10 also illustrates a reasonable approximation of the daily demand net of solar profile if all solar capacity that is under construction had been in service producing electricity. To do this, observed solar production in March 2023 was scaled up in each hour by a factor of 2.4, with the resulting demand net of solar curve (illustrated as the dashed line).

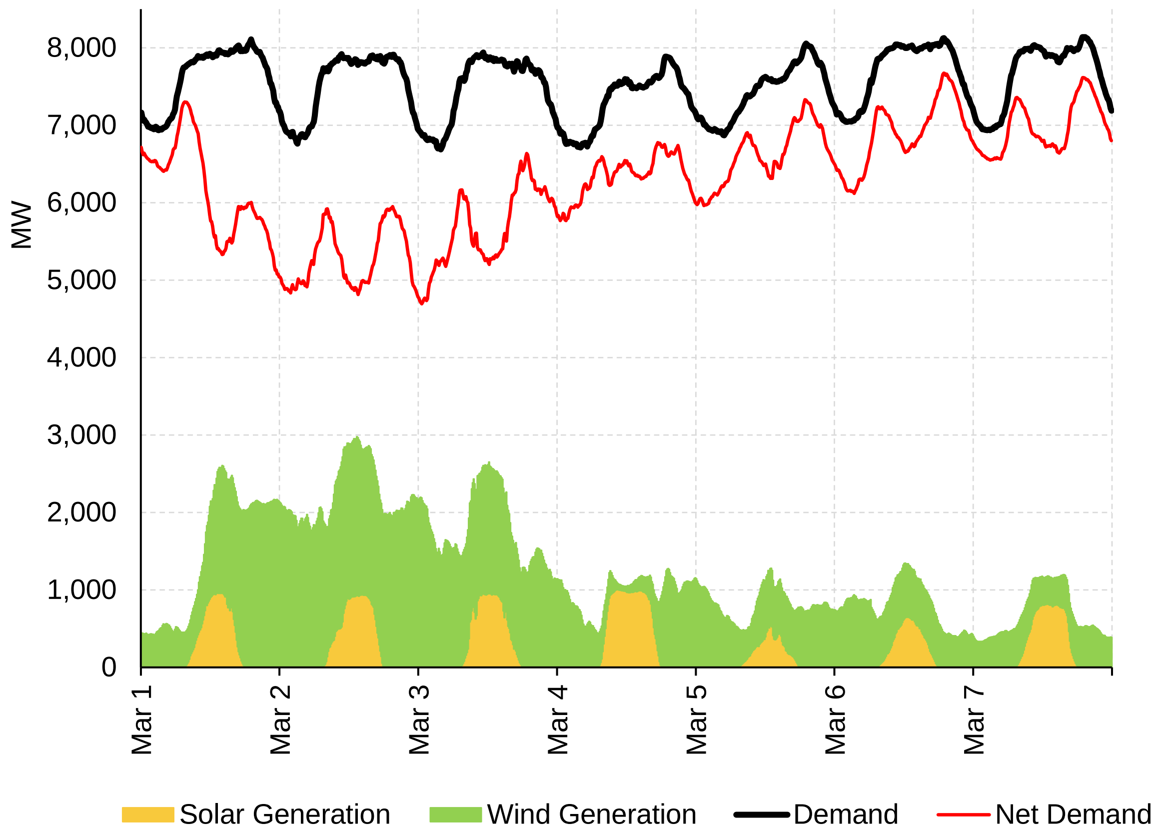
The observed and scaled demand net of solar curves for March 2023 precisely overlap overnight as solar generators did not produce electricity. In hours with solar generation, the scaled demand net of solar curve is below the observed demand net of solar curve. This illustration makes plain that in the near future demand net of solar production in Alberta will routinely reach its minimum in mid-afternoon instead of in the middle of the night as was historically the case.

1.2.2 Net demand: Demand net of wind and solar generation

Net demand is defined as demand less wind and solar generation. The gap between demand and net demand has widened as wind and solar generation have increased. For example, wind and solar generation combined reached almost 3,000 MW on March 2 in HE 14. Increasing volumes of wind and solar generation have changed the shape of the net demand profile, increasing the system ramping requirements.

The AESO dispatches up and down the energy merit order depending on a number of factors, including changes in net demand, which may occur as a result of changes to demand, wind generation, or solar generation. As a result, net demand can exhibit several large ramps throughout the day. Figure 11 illustrates demand and net demand from March 1 to 7.

Figure 11: Demand, wind and solar generation, and net demand (March 1 to 7, 2023)



The magnitude of net demand ramps is expected to increase as more wind and solar generation is added to the grid. In Figure 12, wind and solar generation have been scaled up to reflect wind and solar projects that are currently under construction.

On March 3, from 15:10 to 15:20 net demand increased by 164 MW, or at a rate of 980 MW/h as wind and solar generation fell simultaneously. Had wind and solar generation been scaled up as in Figure 12, net demand may have increased by 377 MW in 10 minutes, an hourly rate of 2,260 MW/h.

Larger and faster changes in net demand pose a reliability challenge. On February 13, wind and solar generation dropped by 370 MW over 10 minutes, from 11:30 to 11:40. Taking this event and scaling wind and solar generation up to reflect projects under construction means wind and solar generation may have dropped by about 666 MW in that 10-minute period. For context, this change is larger than the total volume of regulating, spinning, and supplemental reserves currently dispatched during on-peak hours.

Figure 12: Demand, net demand scaled, scaled wind and scaled solar generation (March 1 to March 7, 2023)

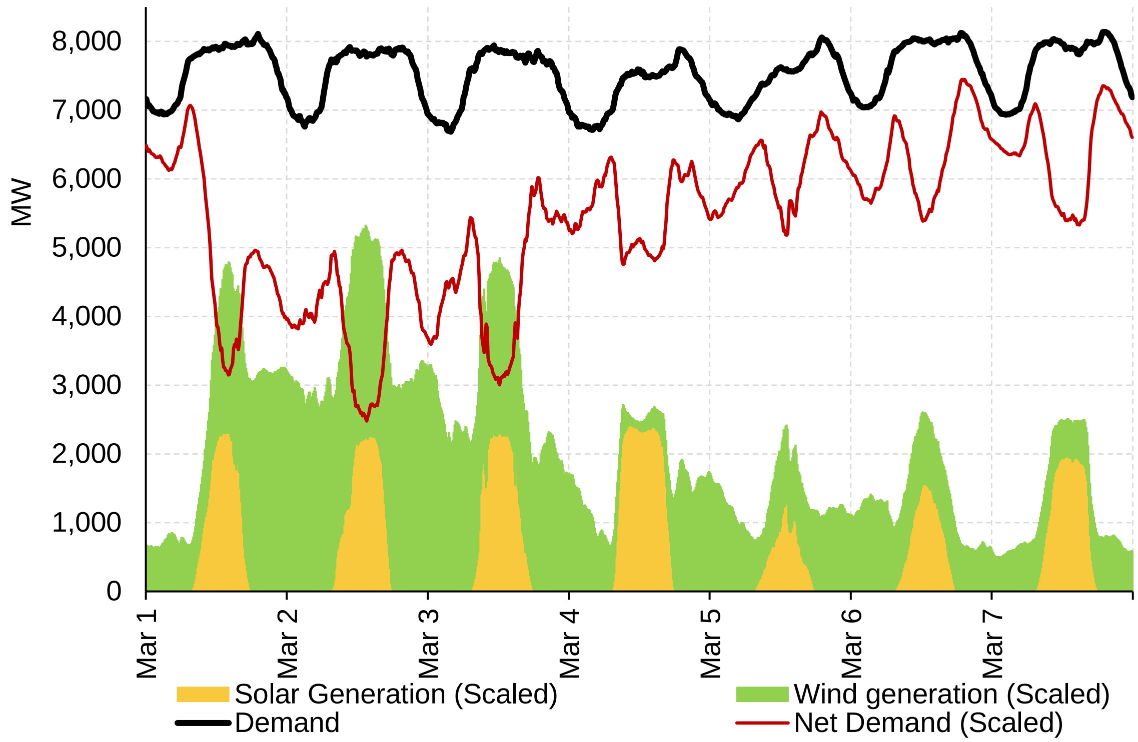


Figure 13: Distribution of 10-minute ramps for demand, net demand, and future net demand (scaled to MW per hour, Q1 2023)

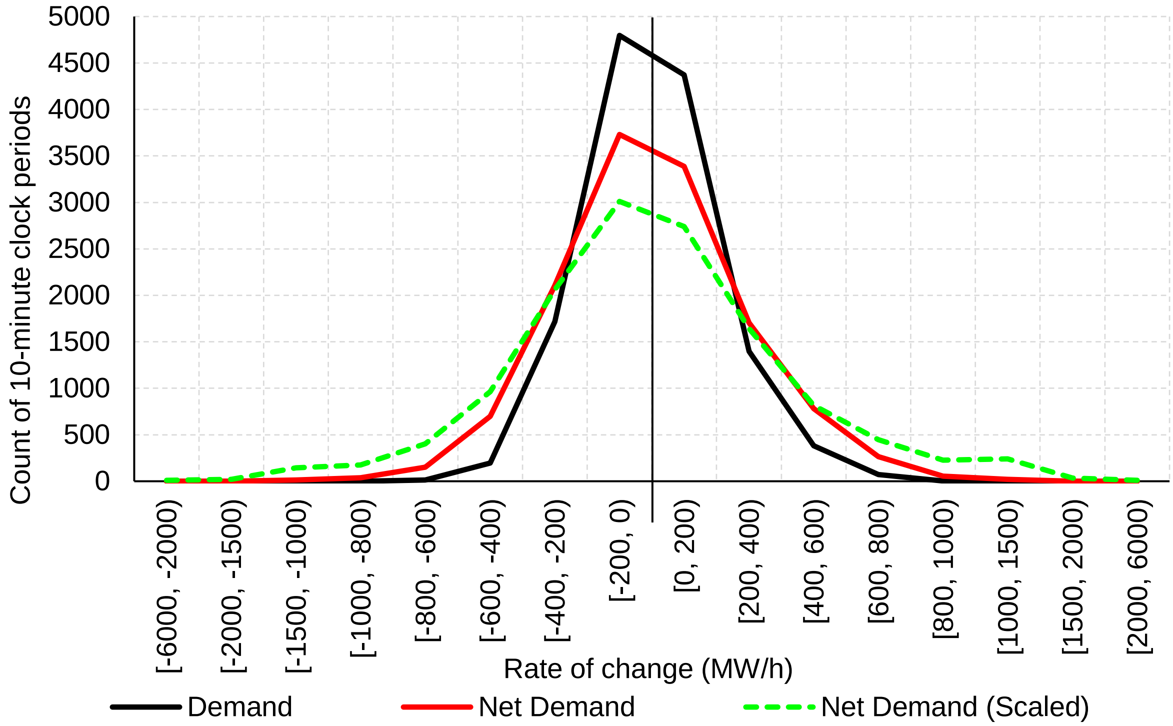
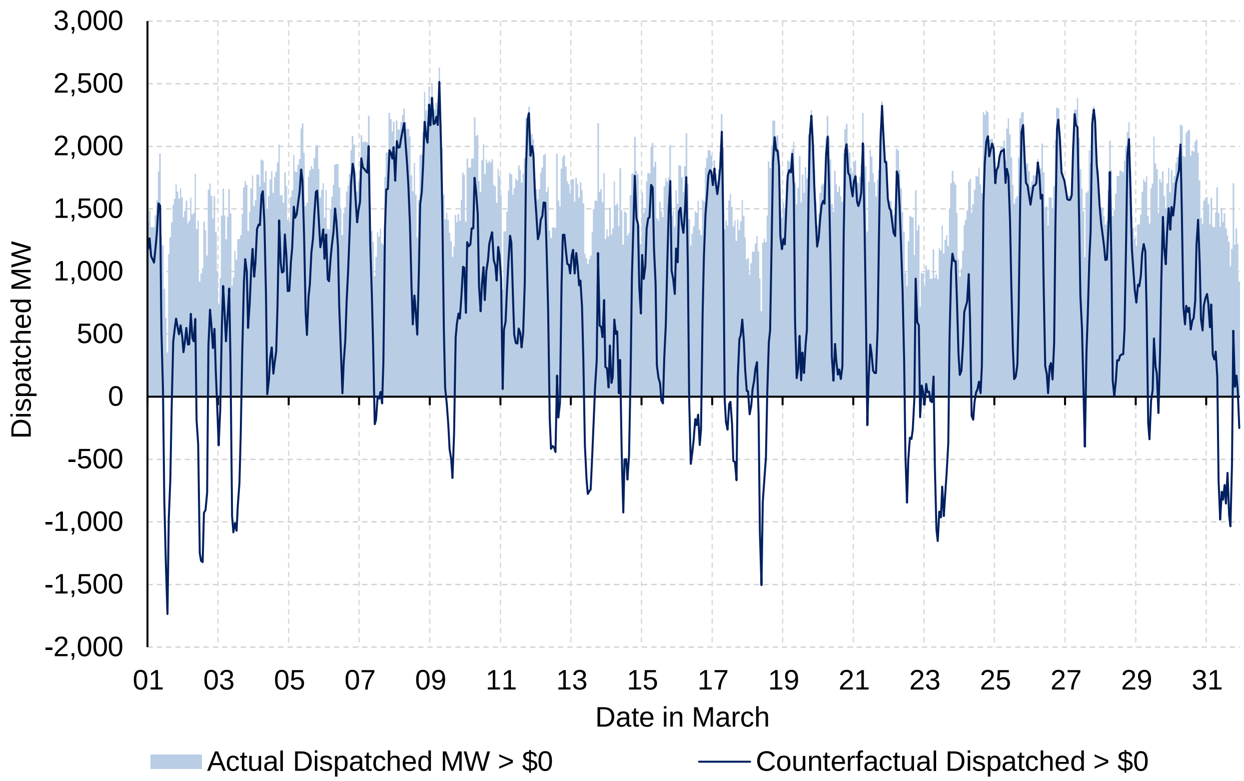


Figure 13 shows the distribution of ramp rates of demand and net demand, at 10-minute observations. The ramp rates are normalized to an hourly level, and reported as MW/h. In Q1 there was one observed 10-minute ramp period where the rate of change in system load (demand) exceeded 1,000 MW/h. Net demand had an absolute ramp rate that exceeded 1,000 MW/h 36 times, or 0.3% of the time. If wind and solar generation were scaled up to reflect projects currently under construction, the absolute ramp rate of net demand would have exceeded 1,000 MW/h for 603 10-minute clock periods, or 4.7% of the time (Figure 13).

In the future, wind and solar capacity will increase further as more projects come online. Figure 14 provides an illustration of how dispatched capacity in the energy market merit order may change with more wind and solar capacity. This analysis increased the wind and solar generation observed in March proportionally to reflect future wind and solar projects that are under construction, and everything else in the market is kept the same for illustrative purposes.

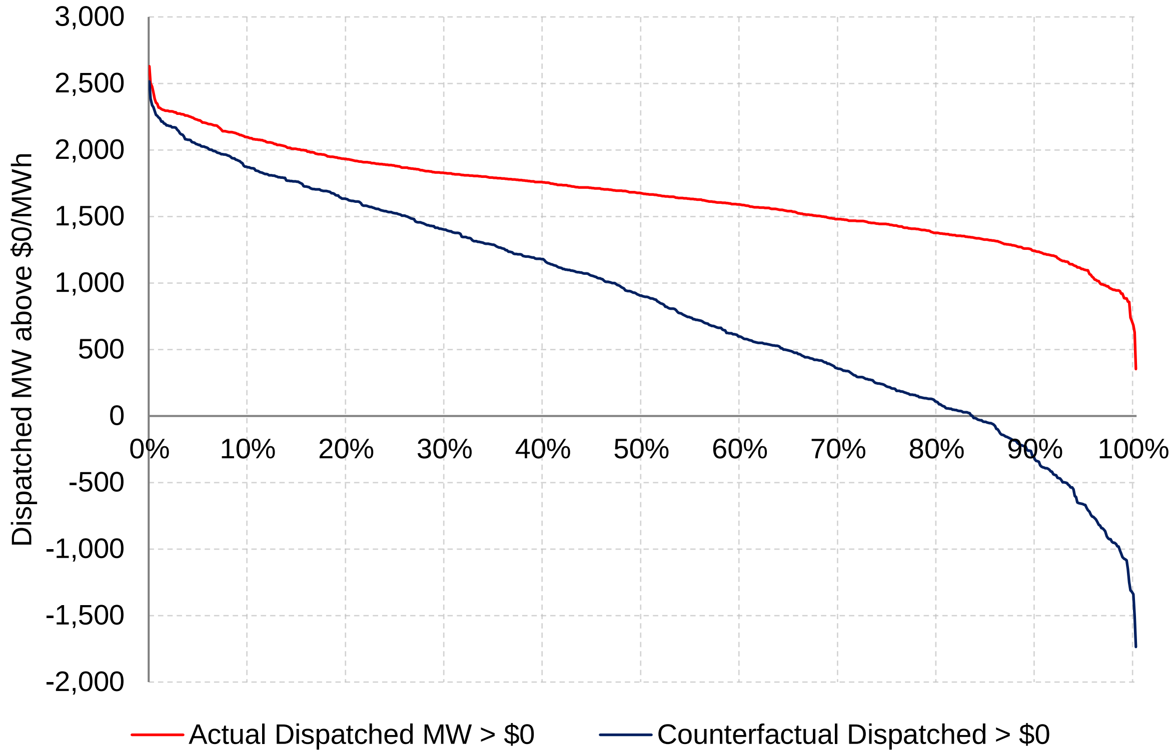
Figure 14: Actual and counterfactual dispatch above $0 (March 1 to 31, 2023)



The higher wind and solar supply will decrease the quantity of capacity that is both offered above $0/MWh and dispatched (mainly thermal capacity), particularly in hours when wind and solar generation are high. However, in some hours, the counterfactual quantity of capacity that is both offered above $0/MWh and dispatched was largely the same as the actual observed quantity, reflecting low observed wind and solar generation.

Figure 15 illustrates the distribution of the actual and counterfactual dispatched capacity above $0/MWh. In all the actual hours the capacity dispatched above $0/MWh was positive, which is consistent with positive prices and no supply surplus events. In 17% of hours in the counterfactual analysis, there are potential supply surplus events meaning that the dispatched capacity above $0/MWh was negative.

Figure 15: Duration curves of dispatched MW above $0/MWh in March (actual and counterfactual)



In addition to the development of renewable capacity, a number of large and efficient thermal assets are being developed in Alberta. For example, the Cascade combined cycle project is scheduled to add 900 MW, the repowering of Genesee 1 and 2 to combined cycle is scheduled to add 512 MW, and the Suncor base plant is scheduled to add 806 MW of cogeneration capacity.[8] The addition of efficient thermal generation capacity will increase supply and put downward pressure on prices.

The expected market consequences of additional wind, solar, and thermal supply may include:

- more commercially offline thermal generation capacity,
- thermal generation assets being mothballed or retired,
- more dispatchable capacity being offered at marginal cost rather than $0/MWh,

[8] AESO Long Term Adequacy Metrics May 2023 and Capital Power Investor Presentation March 2023 at slide 20

- more supply surplus events,
- increased transmission congestion,
- higher export volumes, and
- increased demand.

Going forward, during some high-demand periods, output from wind and solar generation will be low (as shown by the points at the left end of the duration curves in Figure 15). In these hours, large amounts of thermal generation will be needed to meet demand.

1.2.3 Wind forecasting

The AESO publishes hourly wind and solar generation forecasts for the next twelve hours and the next seven days.[9] These forecasts include the minimum, most likely, and maximum level of expected wind generation. This section analyzes the difference between the most likely forecast of wind generation 6-hours out from real-time and actual wind generation (the 6-hour forecast error).[10]

The 6-hour forecast error has trended towards larger negative errors over time, as more wind capacity has been added. This means the wind forecast is more likely to underestimate actual wind generation.

The average wind forecast error has changed from +19 MW in 2019 to -34 MW in 2022 and to 63 MW in Q1 2023. Over this time installed wind capacity increased by about 2,200 MW. Table 6 shows the average 6-hour forecast error, the average error less than 0 MW (average underprediction), and the average error greater than 0 MW (average overprediction).

As shown, moving from 2019 to 2022, the 6-hour forecast has become more likely to underpredict wind generation, and to underpredict by larger amounts. This is reflected in the annual duration curves of 6-hour forecast errors shifting down (Figure 16). The higher absolute forecast error has largely been driven by increased wind capacity over time. As wind has capacity increased, the same percentage forecast error leads to a higher absolute forecast error. Over time, the forecast error relative to available wind capacity has improved.

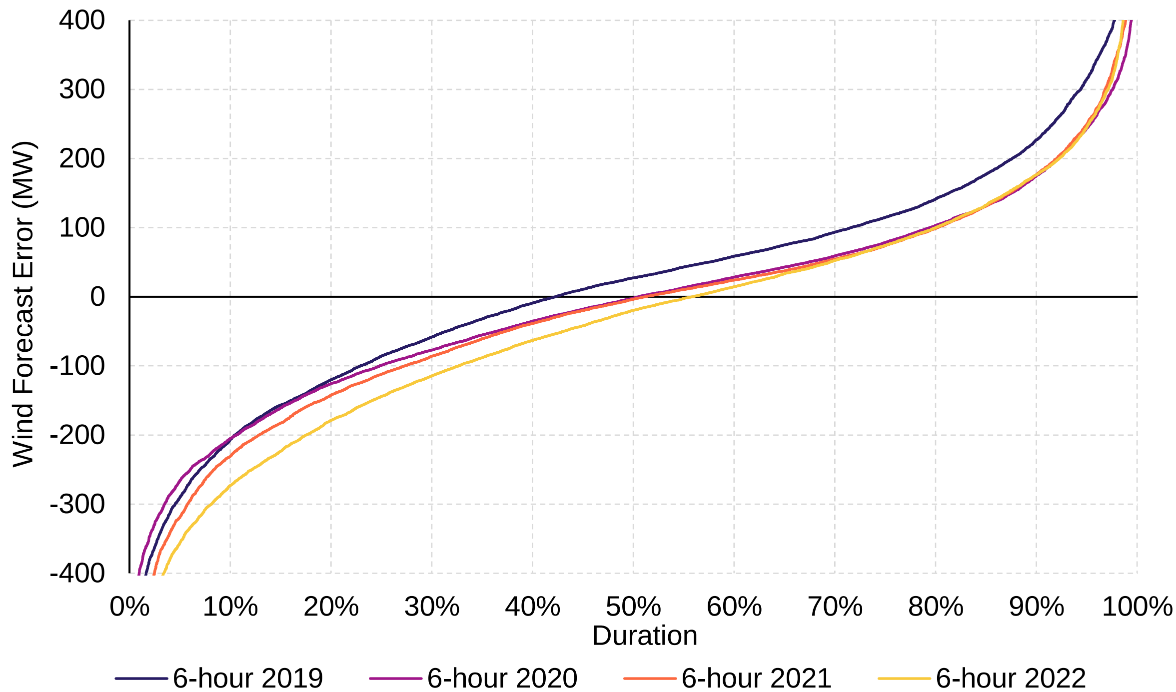
[9] AESO Wind and Solar Forecasts

[10] The AESO Reliability Requirements Roadmap discusses wind forecast errors 10 minutes out (see page 105)

Table 6: Average 6-hour wind forecast error

Year	Avg. forecast error	Avg. error < 0 MW	Avg. error > 0 MW
2019	19 MW	-138 MW (42.1% of hours)	+132 MW (57.9% of hours)
2020	-9 MW	-124 MW (50.5% of hours)	+108 MW (49.5% of hours)
2021	-15 MW	-137 MW (50.8% of hours)	+110 MW (48.9% of hours)
2022	-34 MW	-157 MW (55.6% of hours)	+119 MW (44.3% of hours)
Q1 2023	-63 MW	-183 MW (62.0% of hours)	+133 MW (37.8% of hours)

Figure 16: Annual duration curves of 6-hour wind forecast errors (from +400 MW to -400 MW)

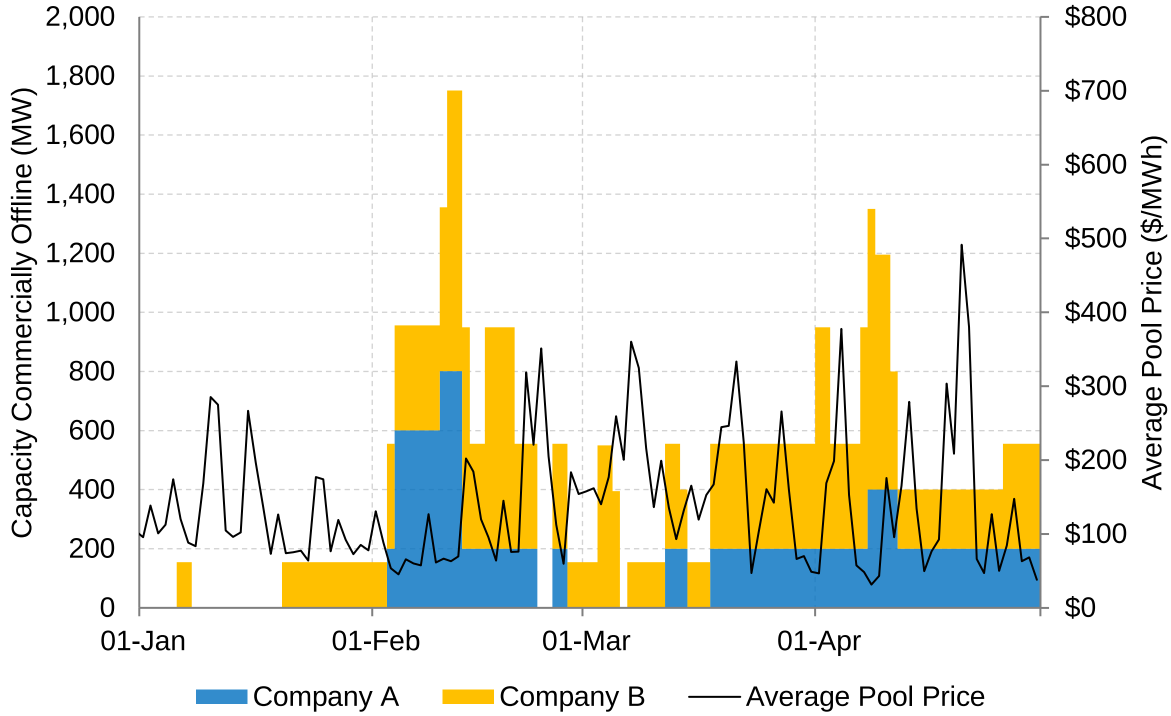


The wind forecast may inform the decisions of market participants regarding generation unit commitment. In Q1, two companies took converted coal capacity offline commercially (Figure 17).[11] From 19:00 on February 10 to 06:00 on February 13, five converted coal assets were commercially offline. In total these assets comprise around 1,750 MW of capacity. For this period, the 6-hour forecast predicted average wind generation of 1,830 MW, or high wind generation.

[11] In this figure, the volume of capacity commercially offline from the Sheerness 1 and 2 assets were attributed equally to Company A and Company B.

Wind generation was high as expected during this period, averaging 1,950 MW of actual generation.

Figure 17: Coal and converted coal capacity commercially offline, by day and company (January 1 to April 30, 2023)



If actual wind generation is lower than forecast this may lead to market participants under-committing generation capacity by having the capacity commercially offline. From February 21 to 23, the 6-hour forecast overpredicted wind generation (Figure 18). For example, the 6-hour forecast over predicted wind generation by 750 MW in HE15 of February 21. On that day, 555 MW of gas-fired steam capacity was commercially offline, even though the daily average pool price was $319/MWh.

The 6-hour wind forecast correctly predicted low wind generation on certain days between April 17 and 21. However, during this period some assets were commercially offline during some high-priced hours and tight market conditions. For example, a 400 MW gas-fired steam asset was commercially offline for the entire work week of April 17 to 21.

On April 20, the hourly pool price reached $912/MWh and the supply cushion fell to 85 MW (Table 7). Same-day natural gas prices were relatively low during this time, and consequently the daily heat rates were elevated on some days, indicating a profitable market for gas-fired steam units that have a variable heat rate of around 10 to 12 GJ/MWh. The MSA will provide further commentary on market events and outcomes in April in its Quarterly Report for Q2 2023.

Figure 18: Wind generation, 6-hour forecast, and forecast error (February 20 to 25, 2023)

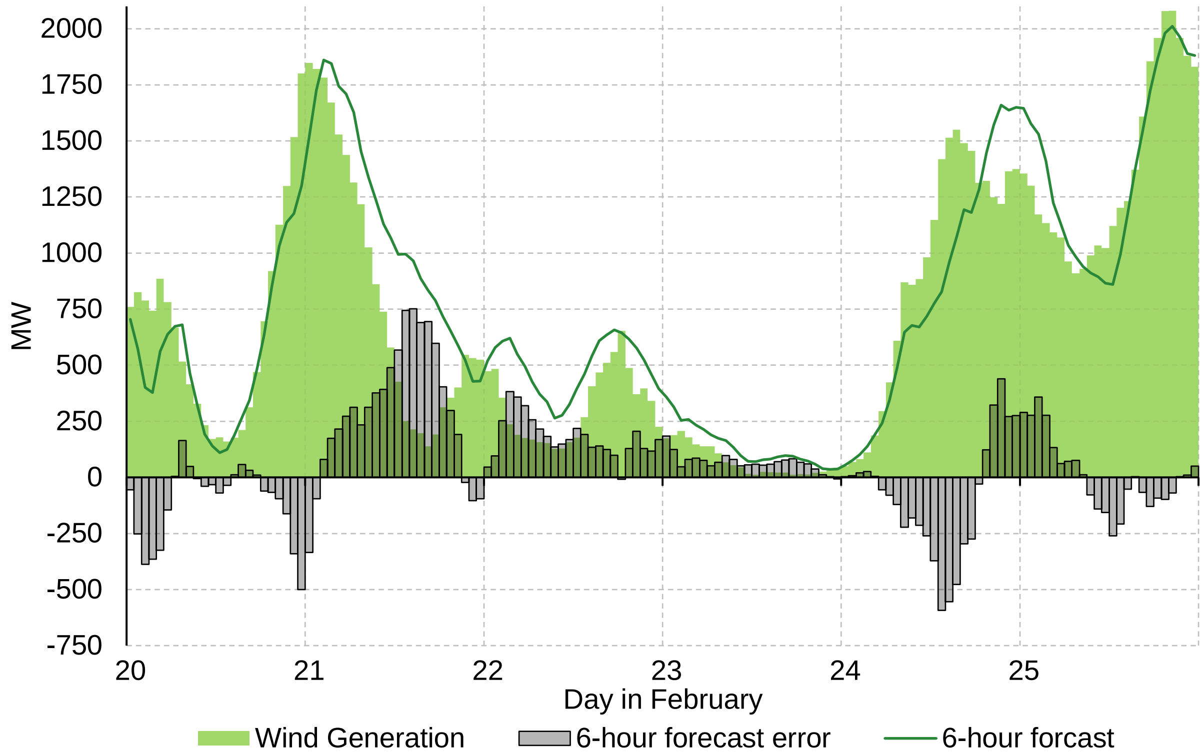


Table 7: Daily figures for pool price, supply cushion, and natural gas price (April 17 to 21)

Date	Avg. Pool Price ($/MWh)	Max. Pool Price ($/MWh)	Min. Hourly Supply Cushion (MW)	Gas Price ($/GJ)	Daily Heat Rate (GJ/MWh)
Apr 17 (Mon)	$92	$615	1,003	$2.43	38
Apr 18 (Tue)	$304	$834	641	$2.47	123
Apr 19 (Wed)	$209	$708	587	$2.35	89
Apr 20 (Thu)	$492	$912	85	$2.45	201
Apr 21 (Fri)	$380	$807	564	$2.37	160

1.2.4 Implications for the electricity market

Alberta has a long history of investment in wind and, more recently, solar generation capacity. Integration of this generation capacity into the electricity market has been largely uneventful. As documented above, substantial new capacity investments have come to market recently, and further investments are currently under construction or are ready to begin construction. Among other reasons, these investments have been driven by:

- declining capital costs of wind and solar generation,

- carbon pricing (including the creation of valuable environmental attributes under the *Technology Innovation and Emissions Reduction Regulation* (TIER Regulation)) and related policy supports, and

- access to an open and competitive wholesale market (including market prices for generation) with no significant barriers to generation investment and connection.

The investment in wind and solar capacity is a key contributing factor to decreases in the carbon emissions intensity of electricity production in Alberta, as reported in section 1.4 and in previous Quarterly Reports.

As documented previously in this section the increase in wind and solar generation means that:

- there will be higher ramping requirements in the future,

- there will be more thermal generation capacity commercially offline, and

- larger wind and solar forecast errors will occur more often.

As a result, the scale of investment in wind and solar generation has implications for how efficiently resources are allocated in the electricity market under the existing ISO rules. Among other things, the MSA is mandated to "assess…whether or not the ISO rules are sufficient to discourage anti-competitive practices in the electric industry and whether or not the ISO rules support the fair, efficient and openly competitive operation of the electricity market."[12]

This calls into question whether the existing ISO rules, which were developed in the past based on the prevailing understanding and expectations, remain ideal in the face of changing technology. As a general matter, there is no reason why they need to be so and the flexible nature of the electricity market, including the ability to change these rules within the market construct itself, makes plain that some degree of change and adaptation is expected to occur.

As documented above, the production profile of wind and solar generation impacts the nature of the net demand that must be satisfied by other generators. These impacts are readily visible in the electricity market and will grow in the future.

In the short run (when installed generation capacity is effectively fixed), wind and solar capacity lowers the pool price when it is producing. However, this impacts the commitment decisions that large thermal generators make on a day-to-day basis which affect sequences of hours irrespective of realized wind and solar production. The reduction in committed thermal supply can offset the impact of additional wind and solar production, though disentangling this effect from the exercise of market power is not a trivial undertaking.

In the long run (when installed generation capacity can change materially), additional wind and solar capacity is expected to displace investment in other generation capacity. In the Alberta

[12] *Alberta Utilities Commission Act*, section 39(3)(d)

electricity market, this is evident in the form of some coal capacity retiring and not being refurbished to run on natural gas or replaced by new thermal capacity. While electricity prices have risen in recent years, the coincidence of increasing wind and solar capacity with the expiration of the Power Purchase Arrangements, and the resulting increase in market power, are difficult to disentangle.

However, continued investment in wind and solar generation will eventually result in lower pool prices on average, potentially much lower than at present in windy and sunny hours, but possibly higher than at present in hours with little wind or sun. Further out, sufficient investment in energy storage used for pool price arbitrage will induce some degree of price convergence.

The long lead time rule and unit commitment and decommitment

While the changing nature of supply due to substantial investment in wind and solar capacity can have many implications for the efficiency of resource allocation under the ISO rules,[13] one issue in particular is discussed here: the long lead time rule.[14] A long lead time asset is defined as an asset that:

(i) requires more than one (1) hour to synchronize to the system under normal operating conditions; or

(ii) is synchronized but has varying start-up times for distinct portions of its MW and which requires more than one (1) hour to deliver such additional portions of its MW; and

which is not delivering all of its energy for reasons other than an outage.[15]

The long lead time rule contains requirements for how these assets participate in the energy market. These include requirements for the pool participant to "enter a start-up time of no greater than thirty-six (36) hours in the Energy Trading System" and "if it wishes to have a long lead time asset that is not synchronized participate in the energy market, enter a start time for the long lead time asset prior to two (2) hours before the start of the settlement interval", which may be restated.[16] Long lead time assets must still submit available capability (AC) equal to their maximum capability (MC) unless they have an acceptable operational reason (AOR), even when not synchronized to the system.

Based on this approach, in Alberta's electricity market, market participants decide independently whether to commit or decommit (i.e., turn on or turn off) their generation capacity. In most other

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[13] The MSA reported on the implications of the $0/MWh offer and market price floor in the context of substantial expected investment in wind and solar generation in section 1.5 of the Quarterly Report for Q1 2021. The AESO's Reliability Requirements Roadmap report discusses physical system needs in considerable detail.

[14] ISO rule 202.4, Managing long lead time assets (ISO rule 202.4)

[15] AESO Consolidated Authoritative Document Glossary

[16] See sections 2 and 3 of ISO rule 202.4. A "start-up time" is a number of hours required for an asset to synchronize to the system, while a "start time" is a date-time that the asset will start.

electricity markets, the electricity system operator implements a coordinated process, usually on a day-ahead basis for the entire following day, to ensure that sufficient generation (in conjunction with other transmission assets) is committed to meet demand for electricity itself, as well as to provide sufficient supply of system support services needed to manage the power system, including accounting for where on the transmission grid the supply is located.[17]

In the past, when Alberta's electricity supply came from a relatively small number of relatively large generating assets, most of these assets stayed online (i.e., remained committed) all of the time except for planned maintenance and unplanned outages. While peaking assets were used as needed, the large generators tended to ramp up during the day to meet higher demand and then ramped down (without turning off) later in the day as demand fell.

As discussed above, the demand net of wind and solar generation that is available to be met by other assets will become much more volatile and unpredictable than in the past. One implication is that large thermal assets are likely to cycle on- and off-line more frequently.

In the MSA's view, the current long lead time rule and the market's decentralized approach to co-ordinating unit commitment is no longer appropriate. In the short term, revision of the long lead time rule is necessary. In the longer term, for resources to continue to be allocated efficiently in the context of substantial investment in wind and solar generation capacity, the development of a market mechanism to manage unit commitment is required, such as a day-ahead market common in other jurisdictions.[18]

None of this should be taken to imply that the Alberta electricity market cannot integrate additional investment in wind and solar generation capacity. It can and will. However, the changing facts of the electricity market will require attention to be directed to whether the specific features of the existing market need to be changed. The MSA will publish a more extensive analysis of the long lead time rule in its next Quarterly Report.

1.3 Market power and offer behaviour[19]

In this section the MSA examines quarterly market outcomes, including the implications of higher wind and solar generation. The frequency and extent of pivotality in Q1 is analyzed, as well as how market prices differed depending on pivotality. Lastly, the MSA examines the offer behaviour of companies in Q1 and prior months, and its relationship with pivotality.

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[17] The AESO's recent Reliability Requirements Roadmap report discusses these system needs in detail.

[18] The AESO' Reliability Requirements Roadmap report identified unit commitment as an issue requiring attention as part of the discussion of flexibility capability (section 5) and noted this and other potential solutions (section 5.4)

[19] The MSA continuously updates its historical inputs to various estimates described in this section. As a result, historical estimates displayed in this section may differ slightly from those reported in previous quarterly reports.

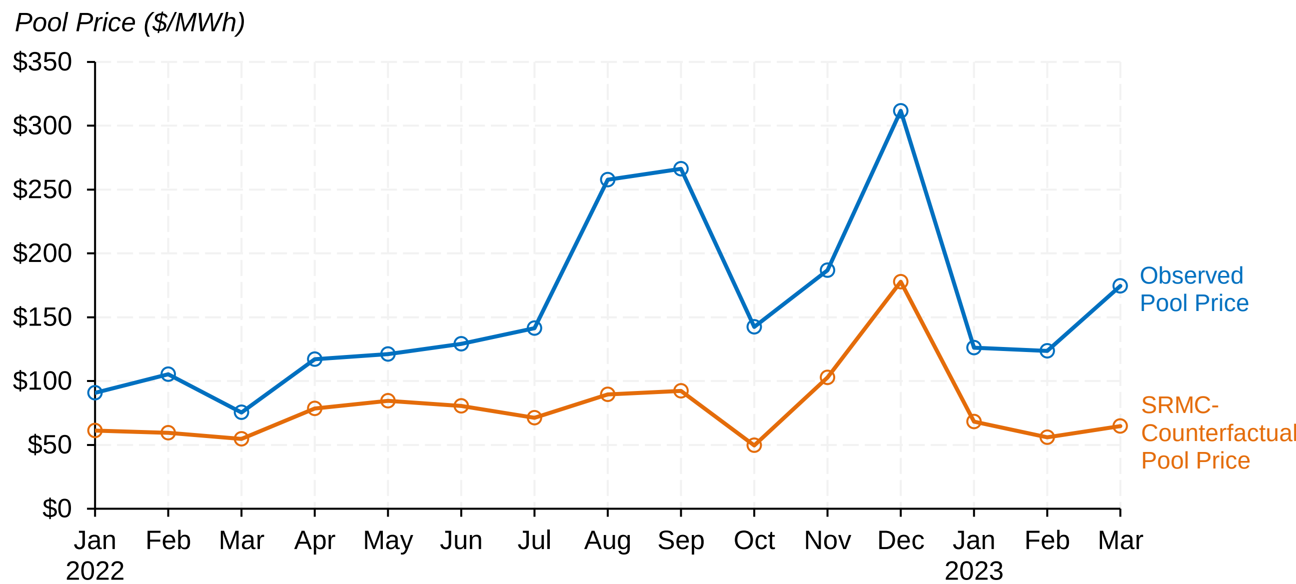
1.3.1 Quarterly market outcomes

Monthly average pool prices were lower in Q1 compared to the previous two quarters, although prices were higher relative to Q1 2022 (Table 8 and Figure 19). The MSA estimates counterfactual pool prices to assess the degree to which changes in pool price may be due to changes in generation costs. In the counterfactual analysis the MSA assumes generation capacity was offered into the market at short-run marginal cost (SRMC). Factors influencing the SRMC-counterfactual prices include natural gas prices, environmental compliance costs, changes in the generation supply mix, and changes in demand, among others. Estimates of pool prices based on SRMCs suggest that year-over-year changes in generation costs were not sufficient to explain the higher pool prices in Q1.

Table 8: Q1 2023 vs. Q1 2022 observed and SRMC-counterfactual pool prices by month

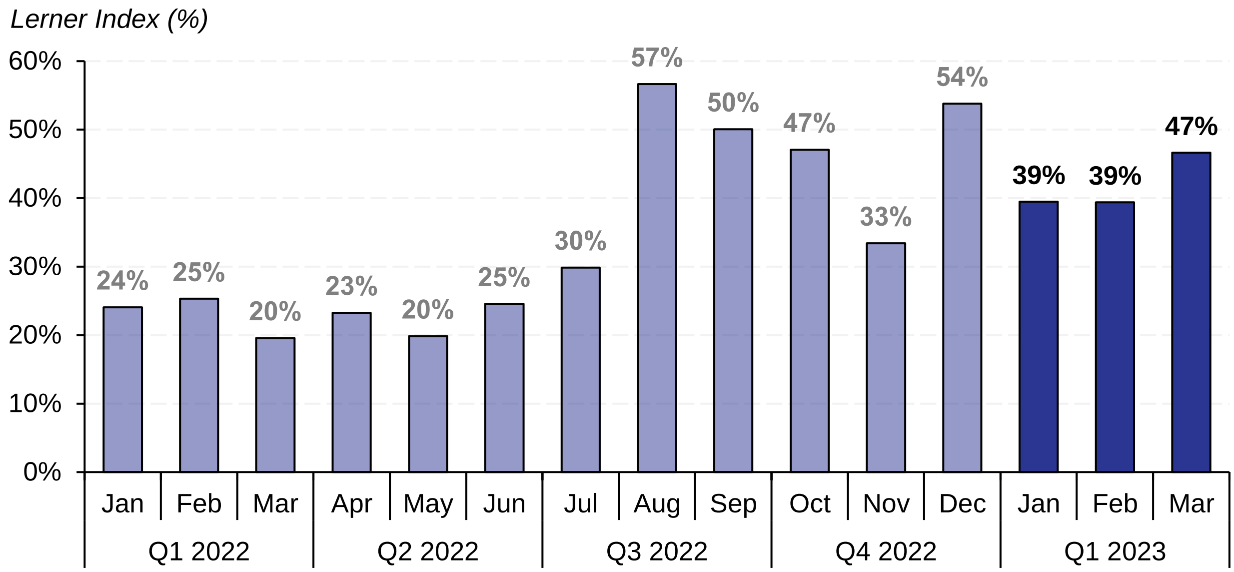
		2023	2022	Change
Observed Pool Price (Avg $/MWh)	Jan	$126.13	$90.81	39%
	Feb	$123.50	$105.22	17%
	Mar	$174.63	$75.38	132%
SRMC-Counterfactual Pool Price (Avg $/MWh)	Jan	$68.34	$61.31	11%
	Feb	$56.05	$59.55	-6%
	Mar	$64.59	$54.74	18%

Figure 19: Observed, SRMC-counterfactual pool prices by month (January 2022 to March 2023)



Market markups measure the markup of price over the market's marginal cost of generation, expressed as a percentage of the price. Market markups continued to remain above early 2022 levels in Q1, averaging 42% compared to 23% in Q1 2022. The mark-ups in Q1 were in line with the Q3 and Q4 2022 averages of 45% in each quarter (Figure 20). In Q1, market markups increased in March alongside an increase in pivotality and the exercise of the market power.

Figure 20: Monthly average market markup (January 2022 to March 2023)



Static inefficiencies are a measure of the societal loss resulting from the exercise of market power. The exercise of market power generates two types of inefficiencies: allocative inefficiency and productive inefficiency. Allocative inefficiency represents the lost value of foregone demand to consumers and marginal generators which occurs when price exceeds short-run marginal cost. Productive inefficiency measures the cost inefficiency that occurs when generators with higher SRMCs are dispatched instead of generators with lower SRMCs, which occurs when less costly generating units are economically withheld.

Static inefficiencies averaged $3.34/MWh in Q1, almost double the average inefficiency of $1.76/MWh in Q1 2022. Monthly average static inefficiencies were highest in March ($4.91/MWh) and lowest in January ($2.14/MWh) (Figure 21). January and February had fewer days where the daily average inefficiency exceeded $5/MWh (three and five days, respectively), while March saw daily average static inefficiency exceed $5/MWh on 13 days (Figure 22).

Figure 21: Monthly average static inefficiency (January 2022 to March 2023)

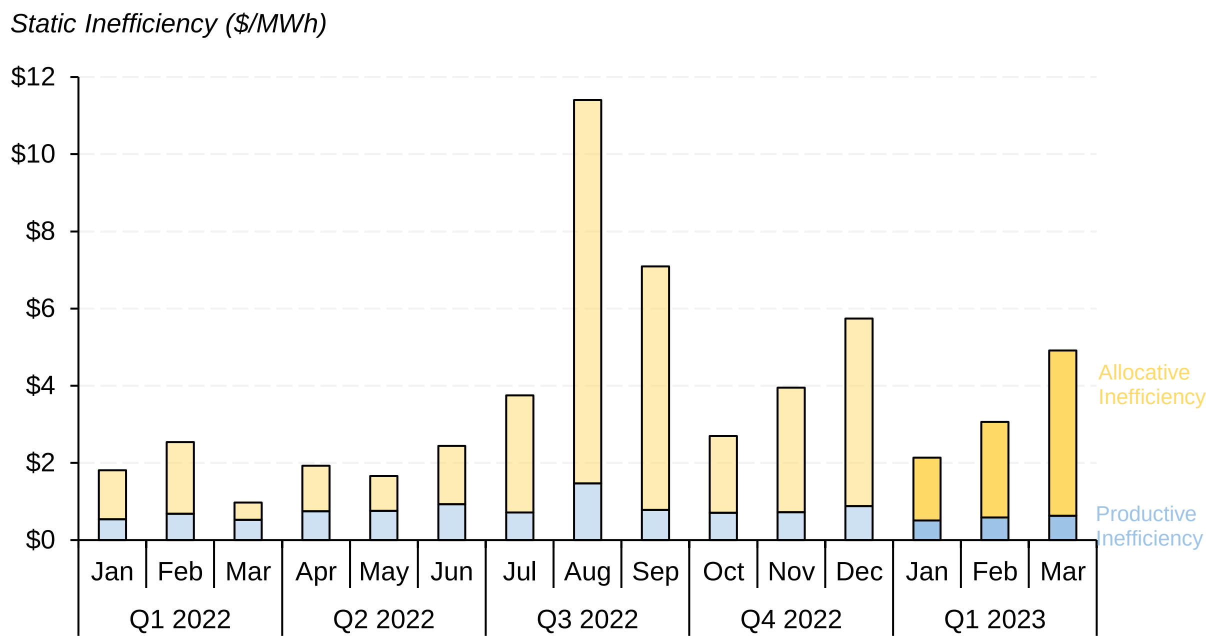


Figure 22: Daily average static inefficiency & average pool prices (January 1 to March 31, 2023)

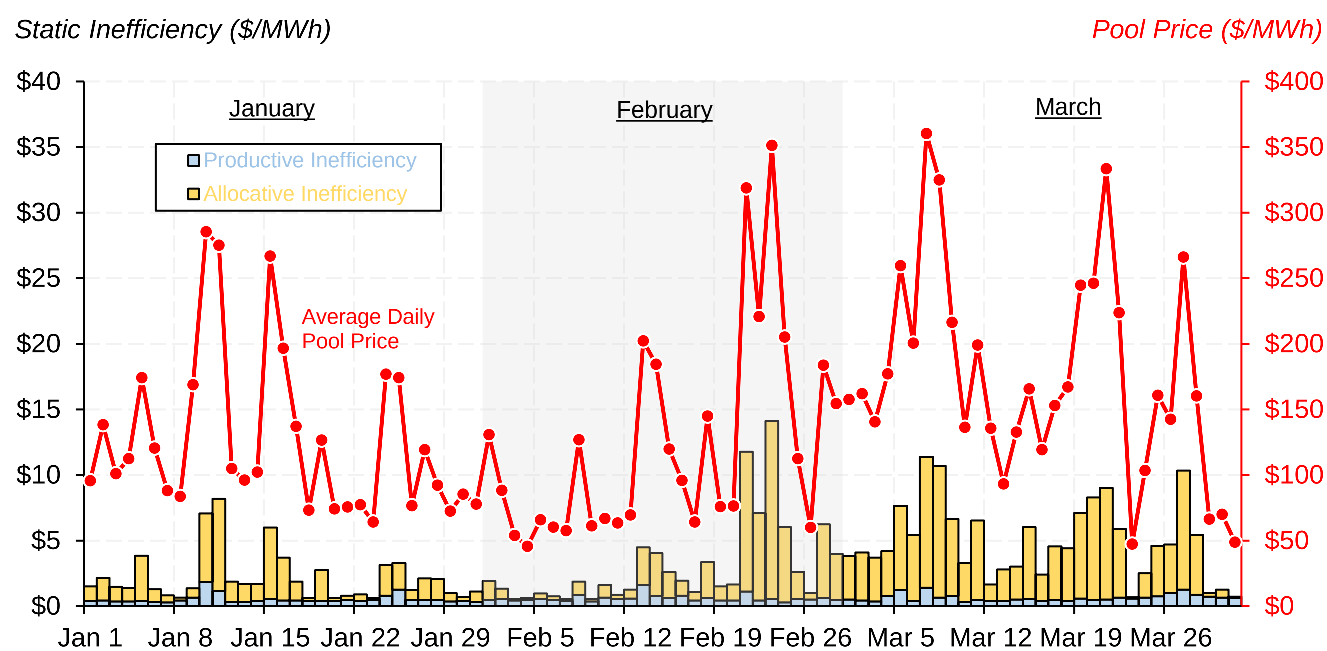
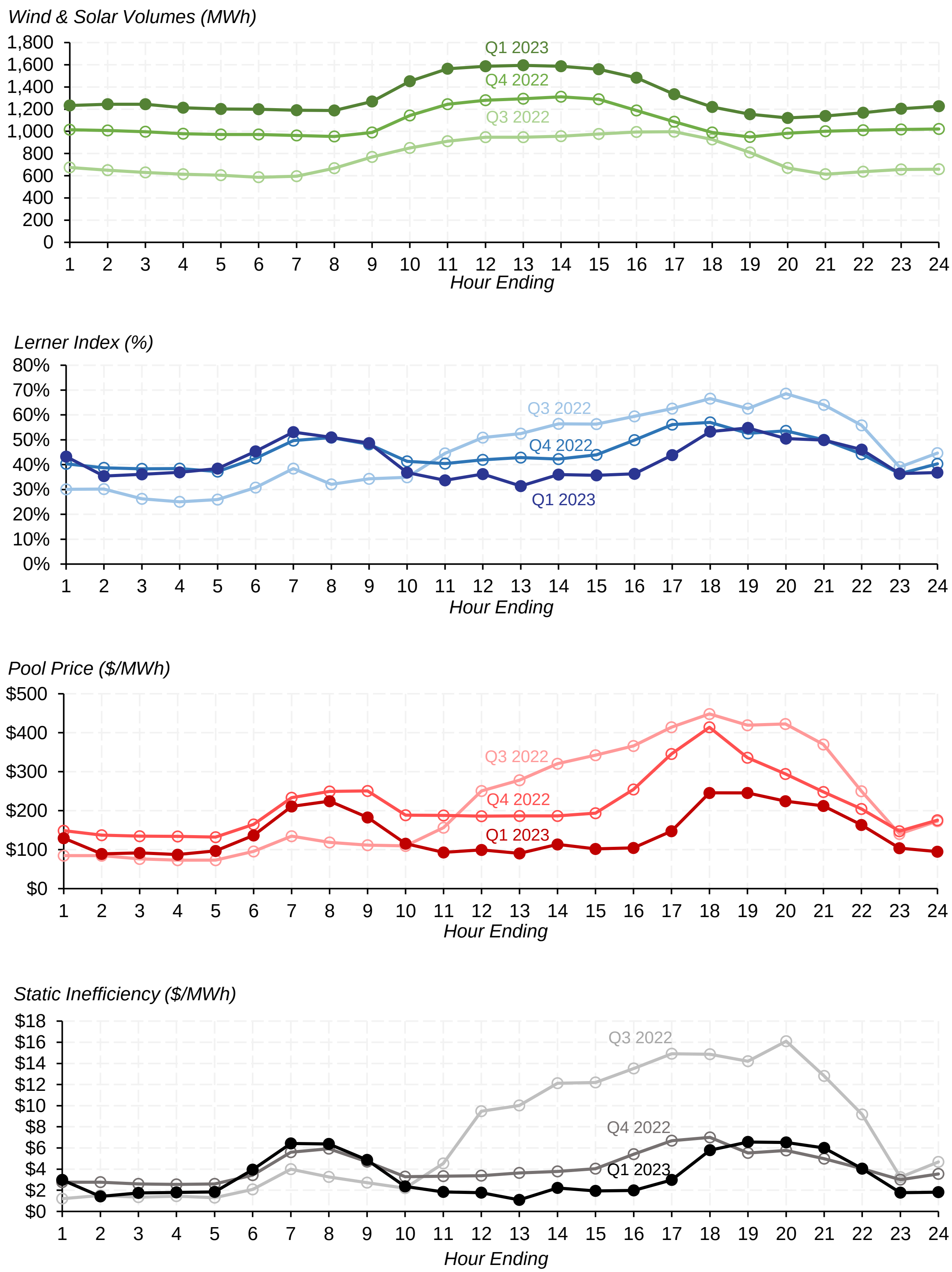


Figure 23: Wind & solar volumes, market markups, pool prices & static inefficiency by hour ending (Q3 2022 to Q1 2023)



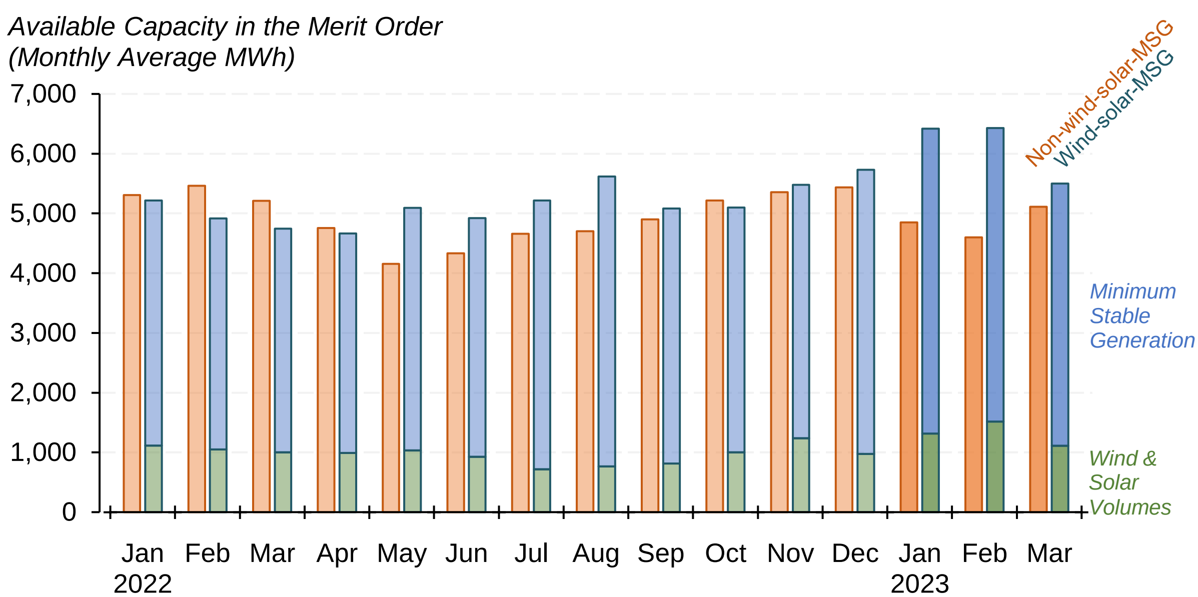
Q1 had greater wind and solar generation compared to the previous two quarters, particularly in hours ending 10 through 17 (Figure 23). The higher generation from these renewable sources was associated with lower pool prices, lower market markups, and lower static inefficiencies, suggesting that generators had less ability to exercise market power in these mid-day hours compared to previous quarters.

Wind and solar generation have a mitigating impact on market power because this supply is normally offered into the merit order at $0/MWh. Minimum stable generation capacity is also typically offered at $0/MWh to maintain dispatch, as thermal generators need to generate above a certain threshold to maintain the stability of a generator.

Wind-solar-MSG capacity output was 23% higher in Q1 compared to Q1 2022, with some of this increase coming from a 24% increase in wind and solar generation over these periods (Figure 24).

In contrast, other capacity ("non-wind-solar-MSG") may be priced above $0/MWh in the merit order and can respond to prices.[20] Capacity in the merit order that can be priced above $0/MWh and respond to prices is referred to as non-wind-solar-MSG capacity. Non-wind-solar-MSG capacity available in the merit order was 9% lower in Q1 compared to Q1 2022 (Figure 24).

Figure 24: Monthly average non-wind-solar-MSG and wind-solar-MSG capacity in the merit order (January 2022 to March 2023)



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[20] MSA has used the term 'non-wind-solar-MSG' to reflect capacity that *can* be priced above $0/MWh (i.e., is above MSG) and respond to prices, rather than all capacity that *is* priced above $0/MWh (referred to in previous MSA reporting as 'dispatchable capacity'). This has increased the MSA's estimates of pivotality.

1.3.2 Pivotality

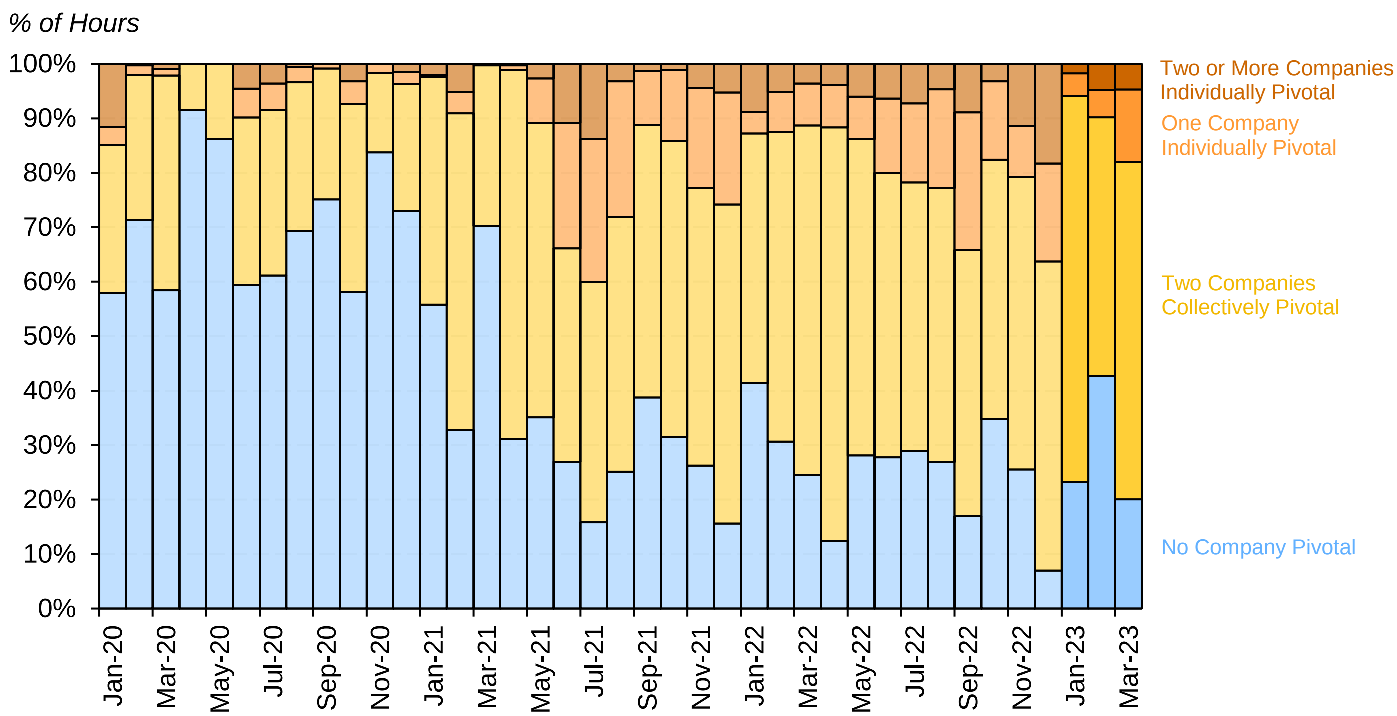
A company is said to be pivotal in hours where that company's non-wind-solar-MSG capacity is needed for the market to clear. In hours where the market is particularly tight, multiple companies may be individually pivotal.

If a company is pivotal, it could price its non-wind-solar-MSG capacity so the market would clear at or above a price of its choice.

In other hours, no company is pivotal on its own (i.e., the market can clear without any individual company's non-wind-solar-MSG capacity) but the market may require at least some of the capacity of two companies' combined non-wind-solar-MSG capacity. These hours are referred to as hours where two companies are collectively pivotal.[21]

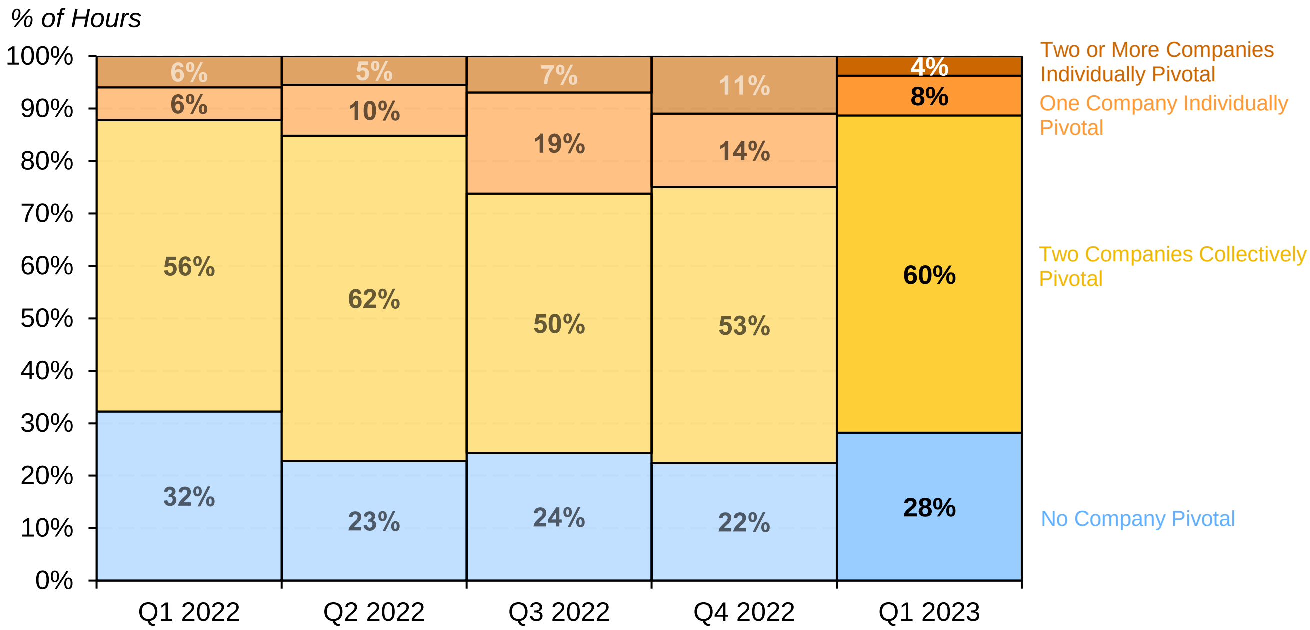
Companies were more frequently pivotal in 2021 and 2022 than in 2020 (Figure 25). The frequency of one or more companies being individually pivotal generally increased throughout 2022. This frequency of this fell significantly in January 2023 due to a combination of lower demand levels, high levels of wind and solar generation, and high generator availability in the energy market (Figure 24). The frequency of companies' being individually pivotal increased in February and March 2023.

Figure 25: Market-level pivotality (January 2020 to March 2023)



[21] In all instances where collective pivotality is discussed in this and the following subsection, this refers to hours where two companies are *only* collectively pivotal, i.e., it excludes hours where one or more companies are individually pivotal.

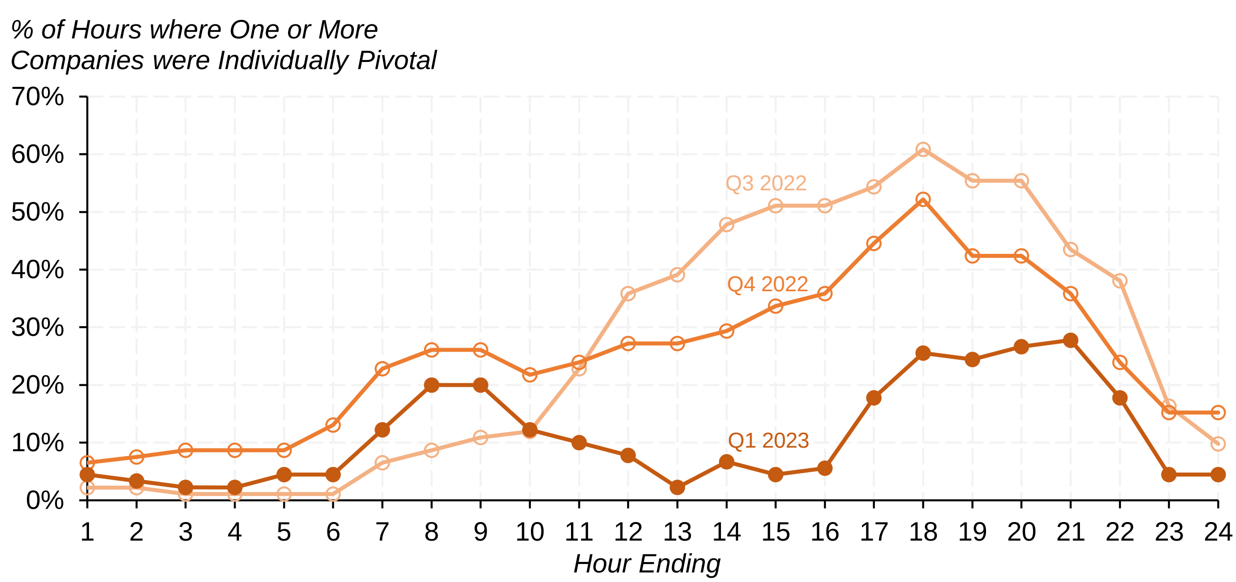
Figure 26: Market-level pivotality (Q1 2022 to Q1 2023)



The frequency with which companies were pivotal was comparable in Q1 2023 and Q1 2022 (Figure 26). For example, at least one company was pivotal in 12% of hours in Q1 2023 and Q1 2022. In Q4 2022, companies were individually pivotal more often, in 25% of hours.

In Q1 2023 individual companies were pivotal most frequently in mid-morning (HE 8-9) and early evening (HE 18-21) hours (Figure 27). This contrasts with Q3 and Q4 2022 where individual companies were more often pivotal over mid-day hours as well. This change in Q1 is a result of higher solar generation.

Figure 27: Individual company pivotality by hour ending (Q3 2022 to Q1 2023)

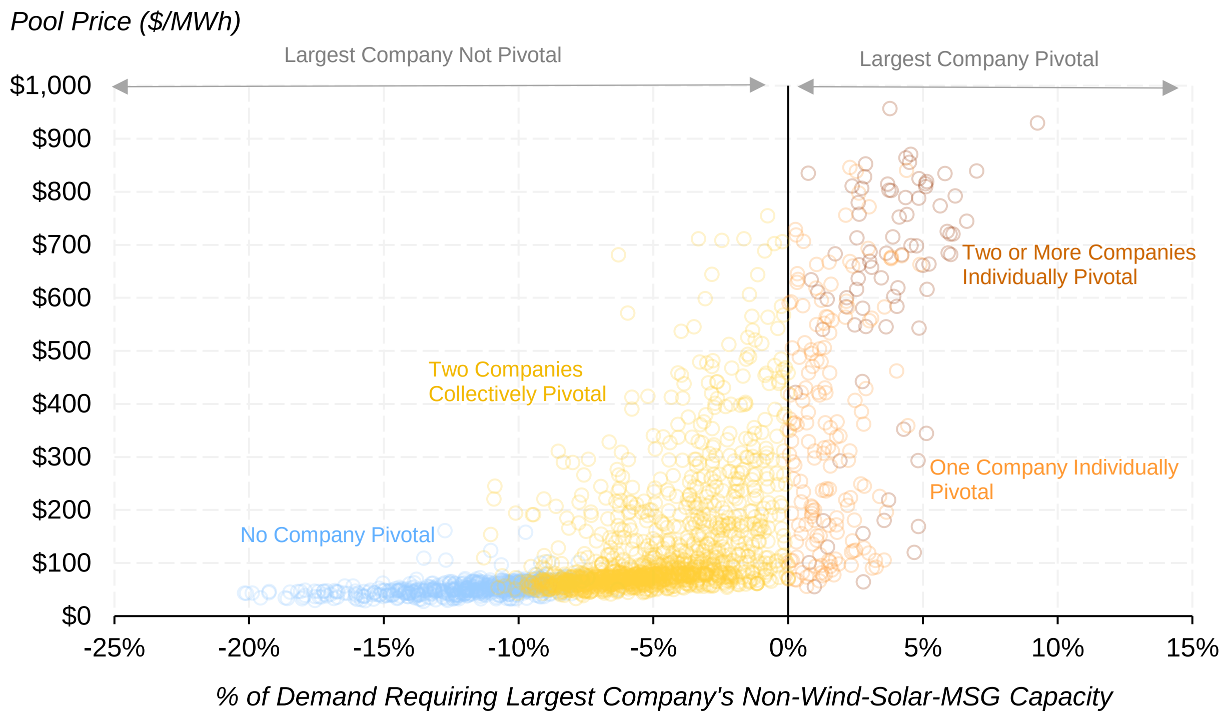


1.3.3 *Outcomes during pivotality conditions*

Pool prices and market markups observed in Q1 were consistent with the exercise of market power in hours where companies were individually pivotal, and in hours when two companies were collectively pivotal.

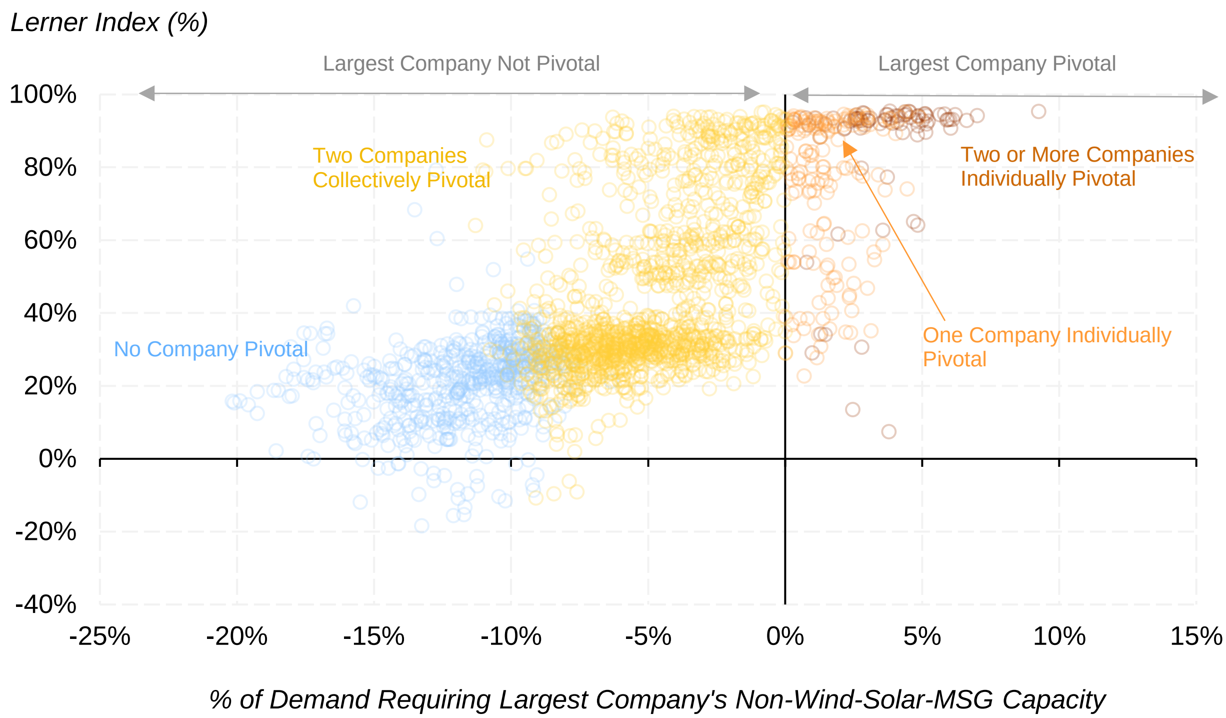
In hours where one or more companies were individually pivotal, pool prices and market markups were typically higher than in hours where no companies were pivotal (Figure 28 and Figure 29). In hours where individual companies were more pivotal (i.e., where a larger share of demand could only be met by their non-wind-solar-MSG capacity), prices and markups were generally higher.

Figure 28: Pool price vs. percent of demand requiring largest company's non-wind-solar-MSG capacity by pivotality condition (Q1 2023)[22]



[22] Negative percentages indicate the degree demand would need to have been higher for the largest company to be pivotal. For example, -20% means that if demand were over 20% higher than observed demand, the largest company would have been pivotal.

Figure 29: Market markup vs. percent of demand requiring largest company's non-wind-solar-MSG capacity by pivotality condition (Q1 2023)



In most hours where no individual company was pivotal, but two companies were collectively pivotal, pool prices and market markups resembled those in hours where no company was pivotal. However, in some hours where two companies were collectively pivotal, pool prices and market markups reached levels more typically observed in hours where one or more companies were individually pivotal (Figure 28 and Figure 29).

Pool prices were $250/MWh or more in 12% of the hours in which two companies were collectively pivotal (Figure 30), and market markups were at least 40% in 40% of the hours where two companies were collectively pivotal (Figure 31). The frequency of high prices and markups during these hours was similar in Q3 and Q4 2022, and greater than the first two quarters of 2022.

Figure 30: Quarterly share of hours where pool price was at least $250/MWh by pivotality condition (Q1 2022 to Q1 2023)

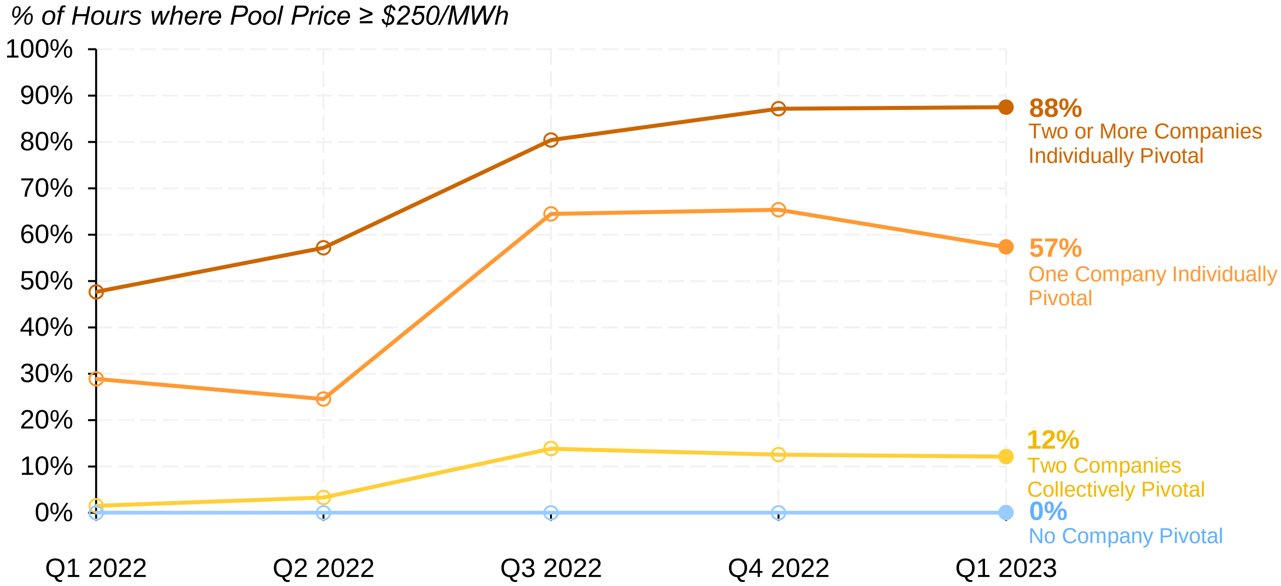
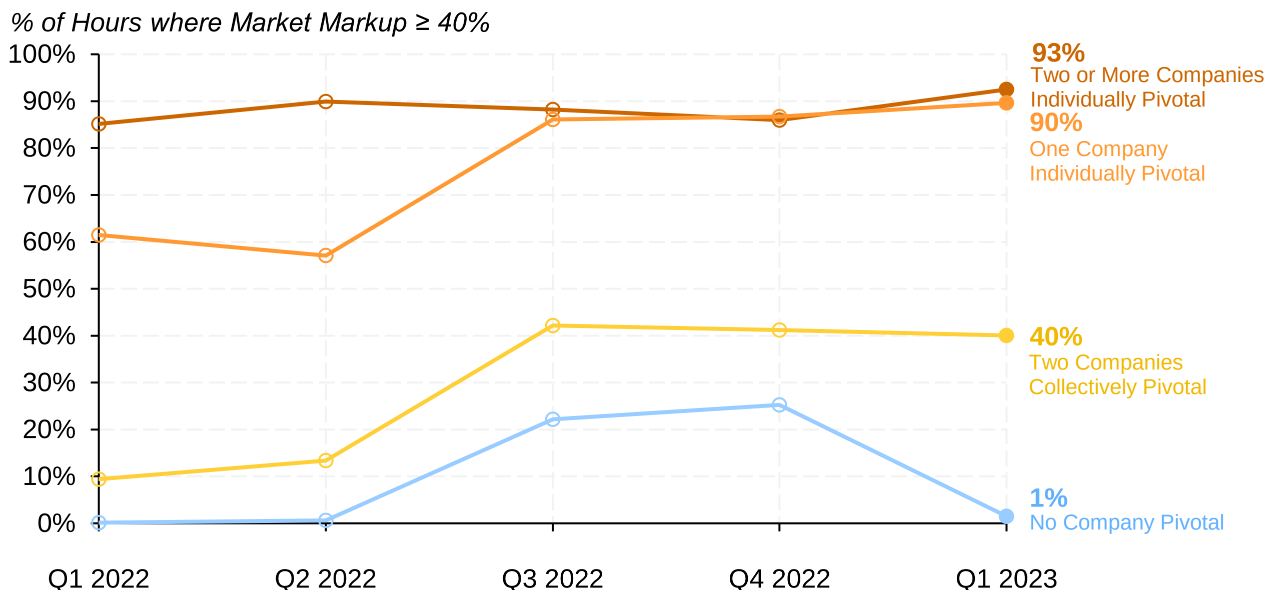


Figure 31: Quarterly share of hours where market markups were at least 40% by pivotality condition (Q1 2022 to Q1 2023)



Monthly average pool prices and market markups were generally similar in Q1 when compared with Q3 and Q4 2022 for given a pivotality condition (Figure 32 and Figure 33). However, market markups in hours where two or more companies were individually pivotal increased quarter-over-quarter, despite these conditions occurring in hours with greater average supply cushion in Q1.

Figure 32: Monthly average pool price by pivotality condition (January 2022 to March 2023)

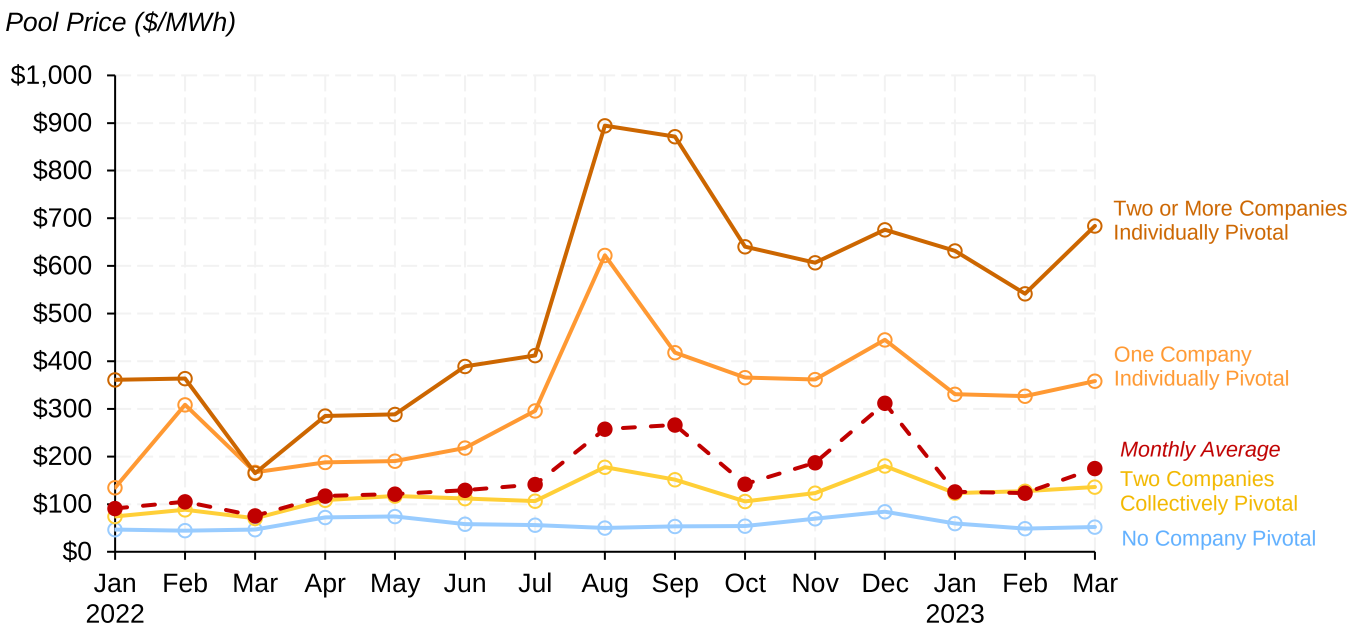
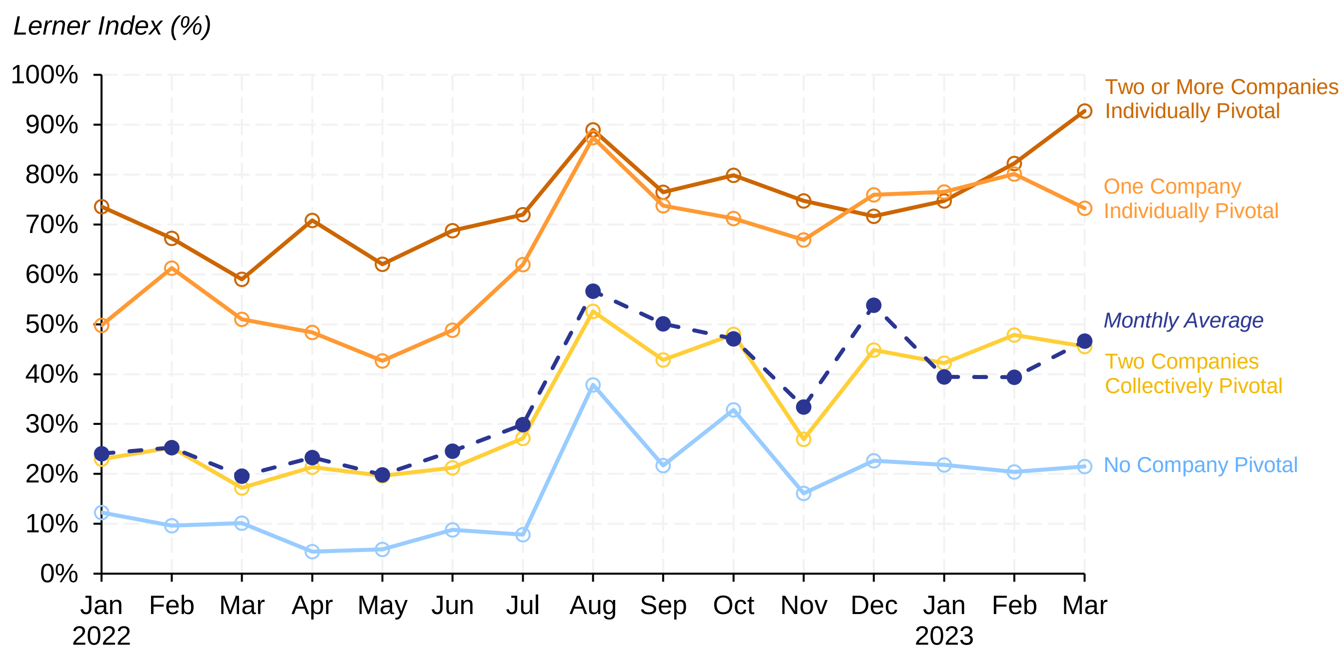


Figure 33: Monthly average market markup by pivotality condition (January 2022 to March 2023)



1.3.4 Offer behaviour

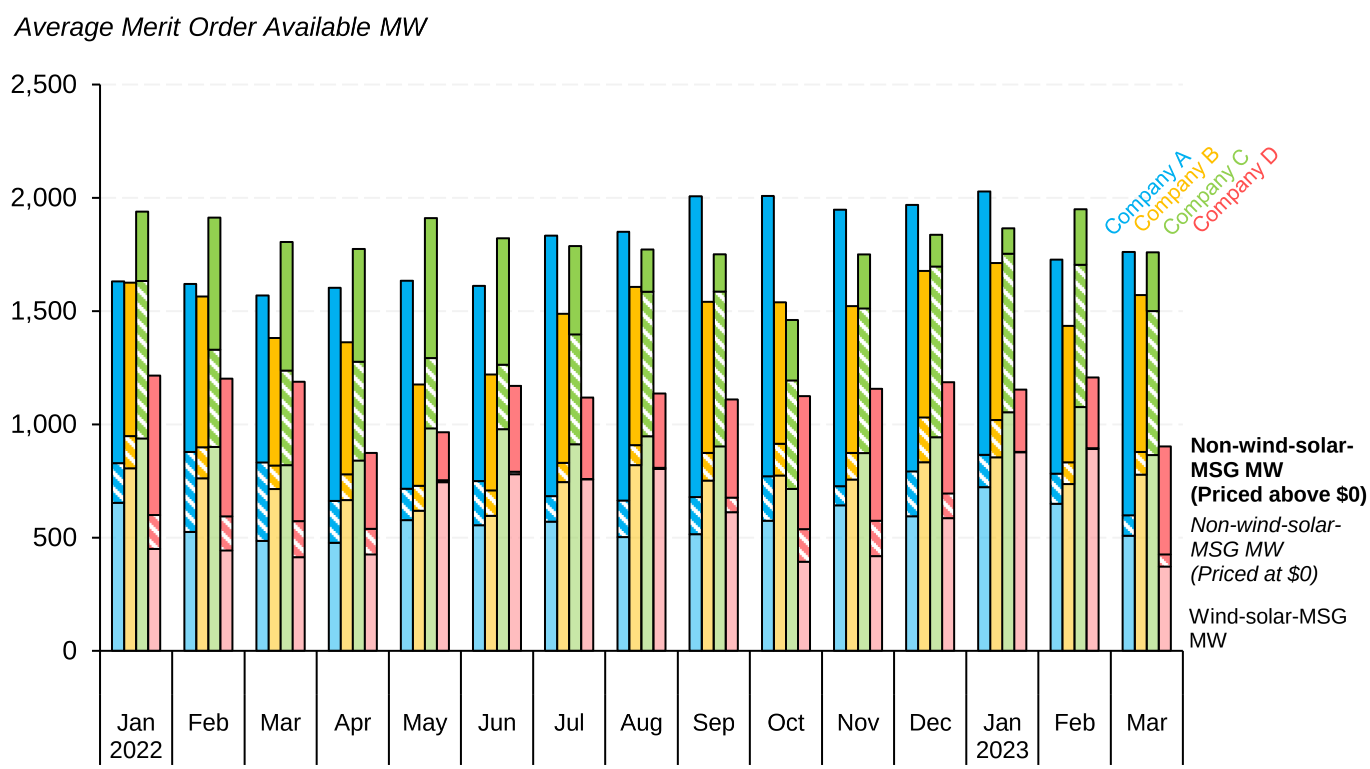
To assess the exercise of market power by particular companies, the MSA analyzed the offer behaviour of four companies (A, B, C, and D) when they were pivotal. These companies are all large generators in the Alberta power market and offer both non-wind-solar-MSG and wind-solar-MSG capacity into the merit order (Figure 34).

Non-wind-solar-MSG capacity is capacity that can respond to market prices and conditions and affects the frequency of a company being pivotal. Wind-solar-MSG capacity typically generates regardless of price and receives pool price. Therefore, more wind-solar-MSG capacity may increase a company’s incentive to exercise market power.

In Q1 2023, Company A had the most non-wind-solar-MSG capacity in the energy market merit order (averaging 1,217 MW), followed by Company C (860 MW) and Company B (786 MW).

While non-wind-solar-MSG capacity can be priced above $0/MWh, it does not necessarily have to be priced in this manner. For example, since Q3 2022 Company C has priced the majority of its non-wind-solar-MSG capacity at $0/MWh.

Figure 34: Average non-wind-solar-MSG & wind-solar-MSG capacity available in the energy market merit order by month and company (January 2022 to March 2023)



Company A was the company most often individually pivotal in Q1, as was the case in 2022 (Figure 35 and Figure 36). Company B has not been individually pivotal on its own since February 2022, because in all hours where Company B has been individually pivotal other companies have also been individually pivotal. In hours where Company B has only been collectively pivotal with another company since July 2022, it has normally been collectively pivotal with Company A.

Figure 35: Company A pivotality (January 2022 to March 2023)

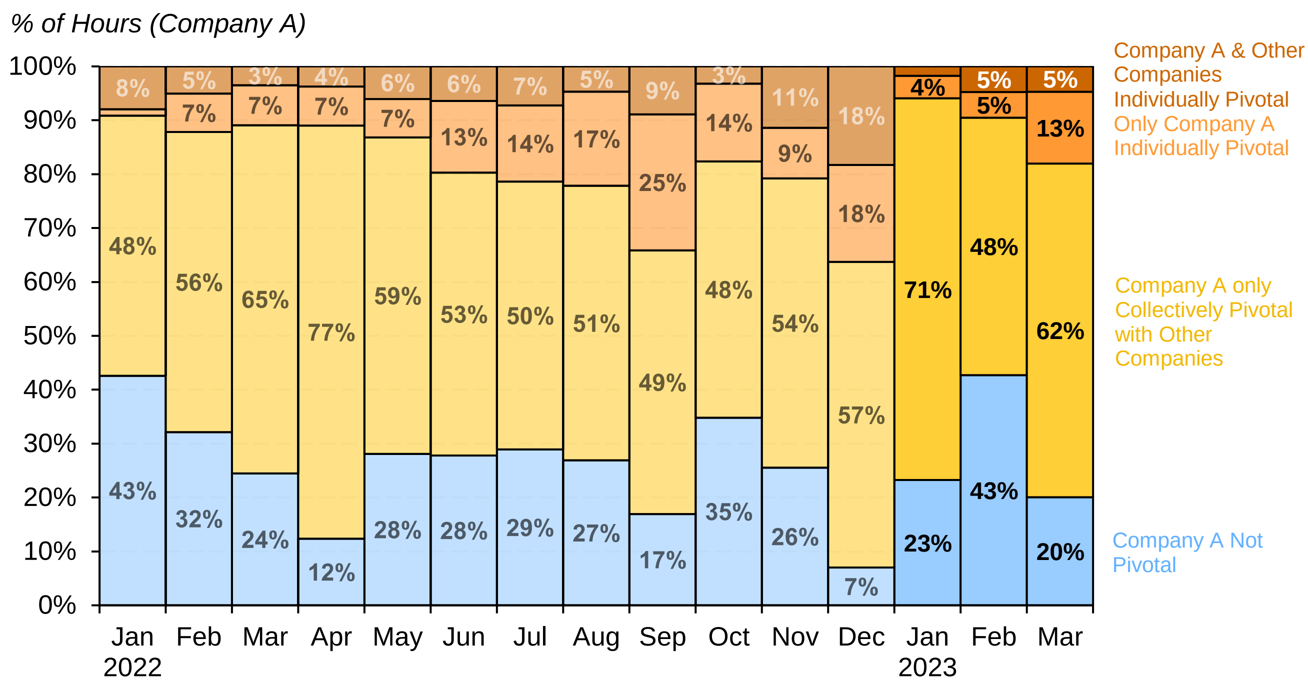


Figure 36: Company B pivotality (January 2022 to March 2023)

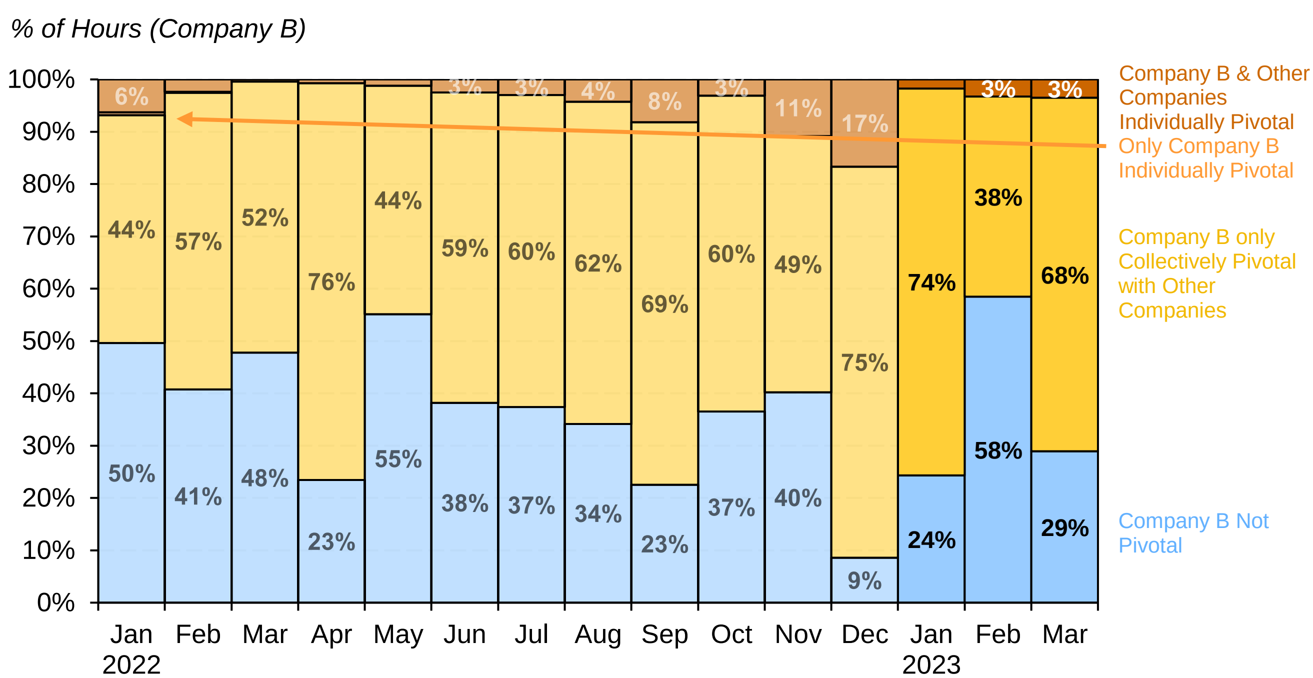
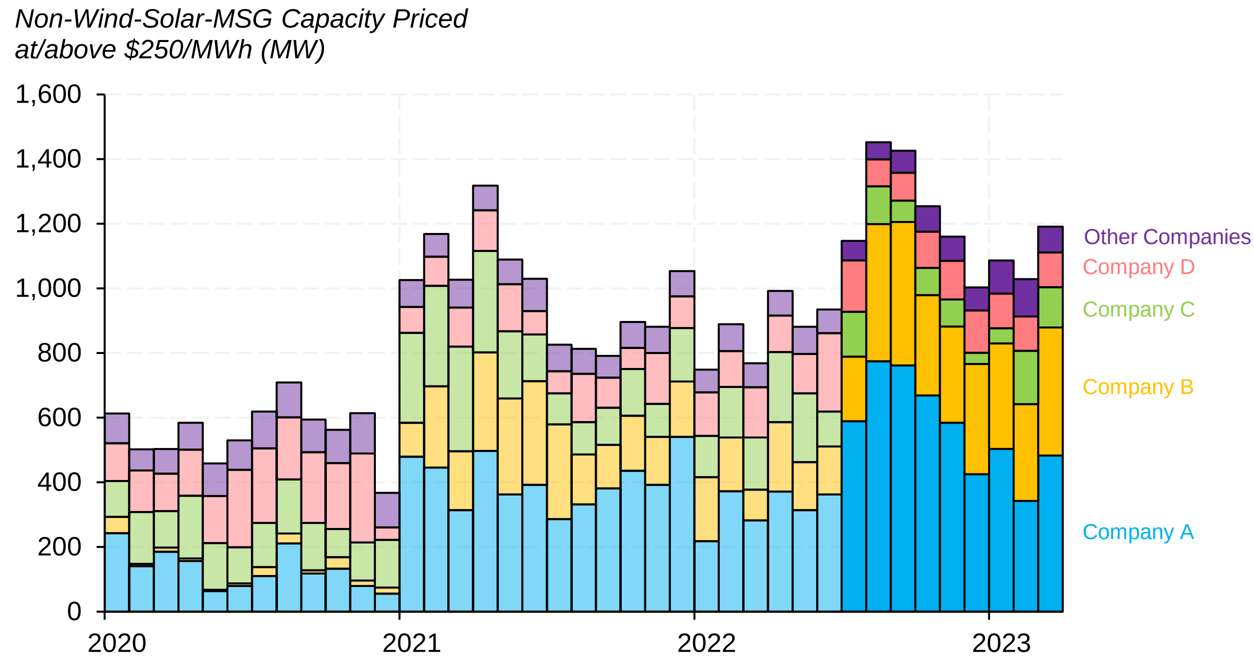


Figure 37: Monthly average non-wind-solar-MSG capacity priced at or above $250/MWh in the merit order by company (January 2020 to March 2023)



In Q1, an average of 1,105 MW of non-wind-solar-MSG capacity was offered at or above $250/MWh, a 34 MW decline relative to Q4 2022, and 236 MW lower than in Q3 2022. However, the Q1 average was higher year-over-year as only 800 MW of non-wind-solar-MSG capacity was offered at high prices in Q1 2022.

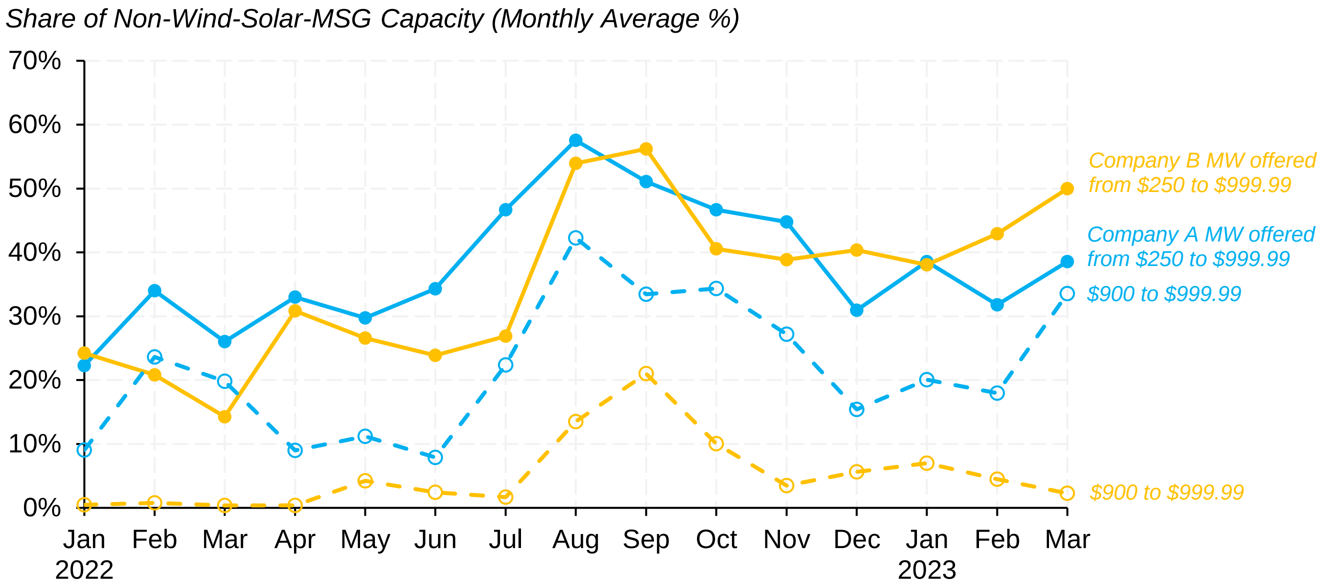
Since January 2021, Company A and B have offered the most non-wind-solar-MSG capacity at prices of $250/MWh or more in the energy market (Figure 37).

In July and August 2022, Company A significantly increased its non-wind-solar-MSG capacity offered at $250/MWh or more, with much of this capacity being priced at $900/MWh or more. Company B did the same in August and September (Figure 38).

Company A reduced the average quantity of its offers between $250/MWh and the price cap over the remainder of 2022, while Company B continued to offer a significant share of its non-wind-solar-MSG capacity at these prices, following initial reductions in September 2022. Capacity offered at this level in Q4 2022 was greater than in the first half of 2022 which, combined with market conditions in this period, continued to cause high prices in Q4 2022.

In Q1 2023 the frequency of company pivotality declined relative to the previous quarter, but Company A and B continued to withhold capacity above levels seen prior to July 2022, and increased their capacity withheld in March 2023.

Figure 38: Shares of Company A & B non-wind-solar-MSG capacity offered at high price ranges (January 2022 to March 2023)



Of its capacity offered between $250/MWh and the price cap since August, Company A has typically offered most of it at prices of at least $900/MWh (Figure 39). In January and March, Company A withheld more capacity relative to January and March 2022. The increase in economic withholding by Company A year-over-year contributed to higher pool prices at a given level of supply cushion in Q1 (Figure 40).

Figure 39: Average monthly non-wind-solar-MSG capacity offered by Company A at prices between $250/MWh and the price cap (January 2022 to March 2023)

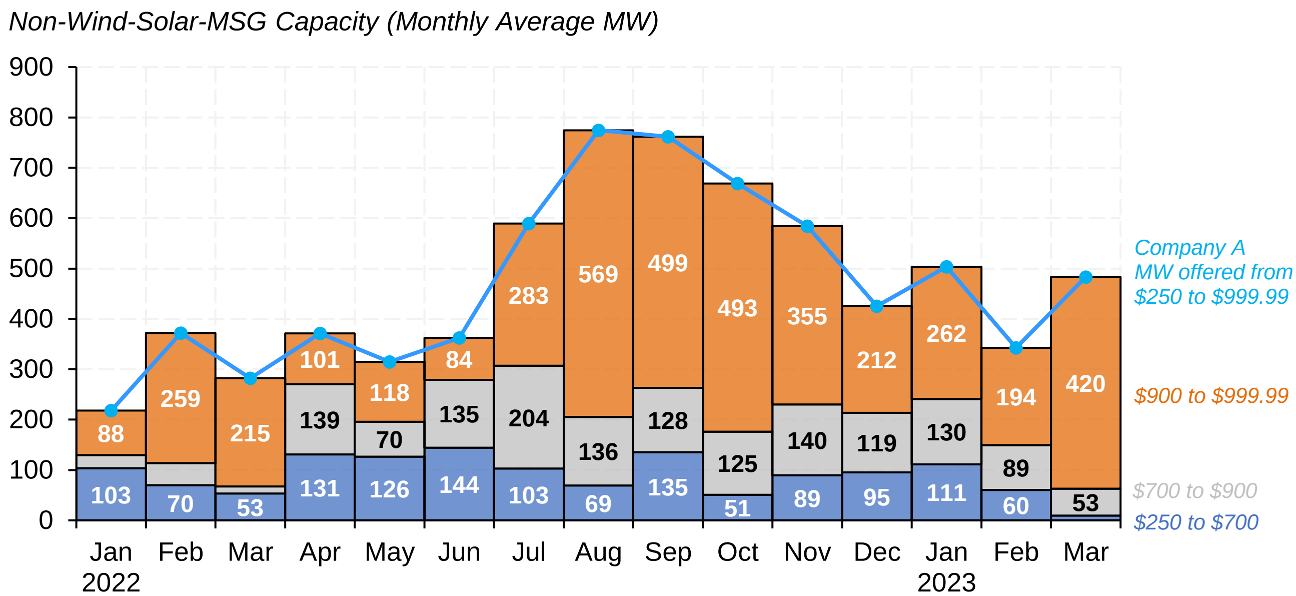
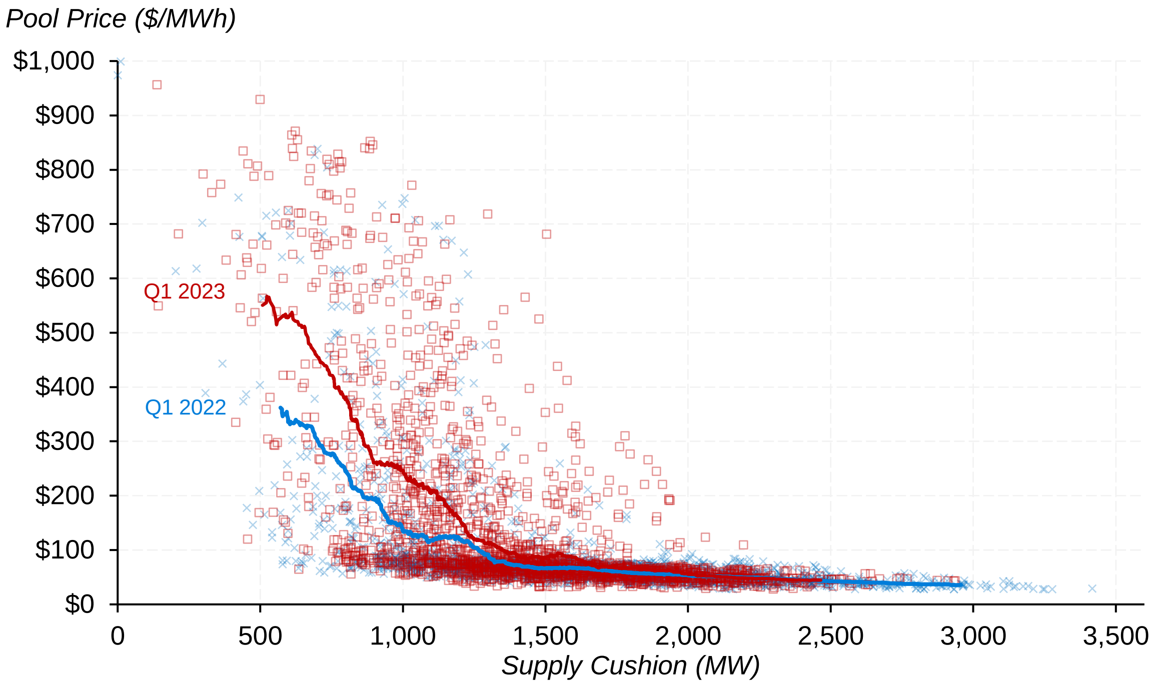
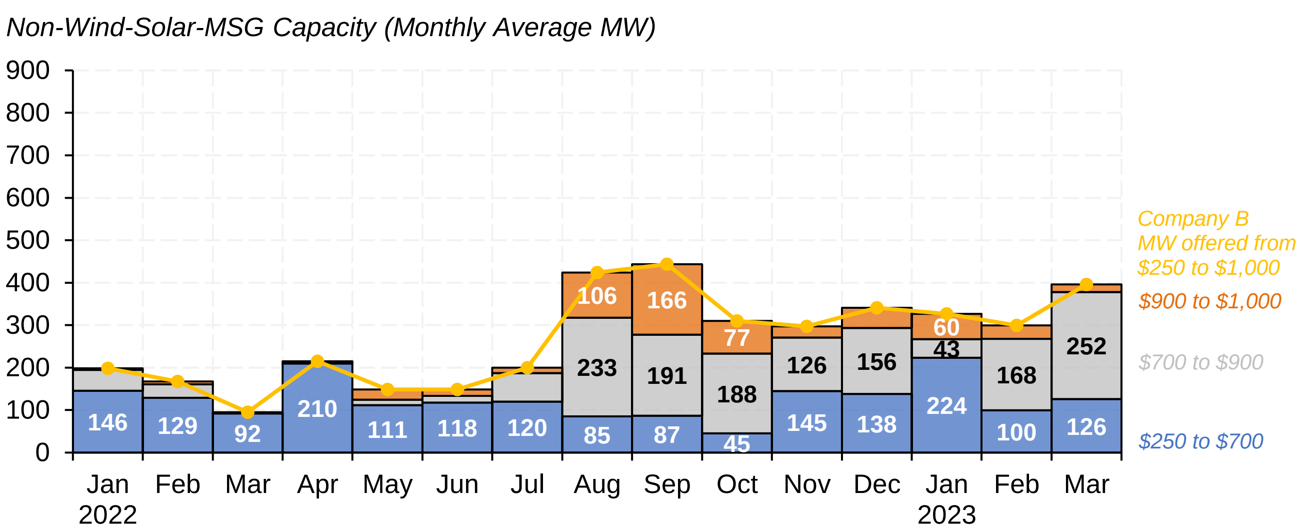


Figure 40: Supply cushion vs. pool price (Q1 2022 vs. Q1 2023)



While Company A offered a significant share of its non-wind-solar-MSG capacity at prices of $900/MWh or more since July 2022, Company B has not, apart from in August and September 2022. Instead, Company B has typically priced a large amount of its non-wind-solar-MSG capacity between $700/MWh and $900/MWh since August 2022 (Figure 41). Company B increased the amount of its non-wind-solar-MSG capacity priced between $700/MWh and $900/MWh in March 2023, coinciding with lower wind generation, more thermal outages, and an increase in Company A's non-wind-solar-MSG capacity offered at $900/MWh or above.

Figure 41: Average monthly non-wind-solar-MSG capacity offered by Company B at prices between $250/MWh and the price cap (January 2022 to March 2023)



In each of the months between September 2022 and March 2023, Company A economically withheld similar amounts of non-wind-solar-MSG capacity in hours where it had different levels of pivotality, except in hours where it and another company were each individually pivotal (Figure 42). In these hours, Company A offered less of its non-wind-solar-MSG capacity at prices of $250/MWh or more and reduced the amount of non-wind-solar-MSG capacity offered at $900/MWh or more (Figure 43). Company A's relatively stable offer behaviour may have incentivized other companies to offer some of their non-wind-solar-MSG capacity below Company A's withheld capacity.

Figure 42: Average Company A non-wind-solar-MSG capacity offered at prices between $250 and the price cap by pivotality condition (January 2022 to March 2023)

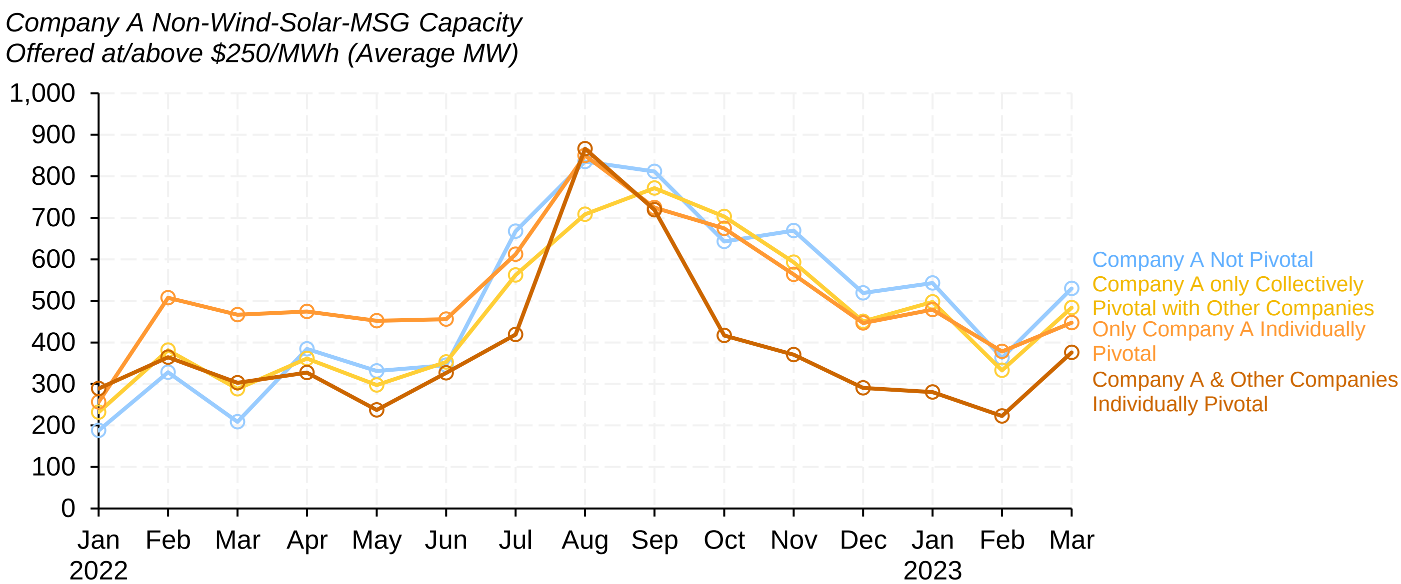
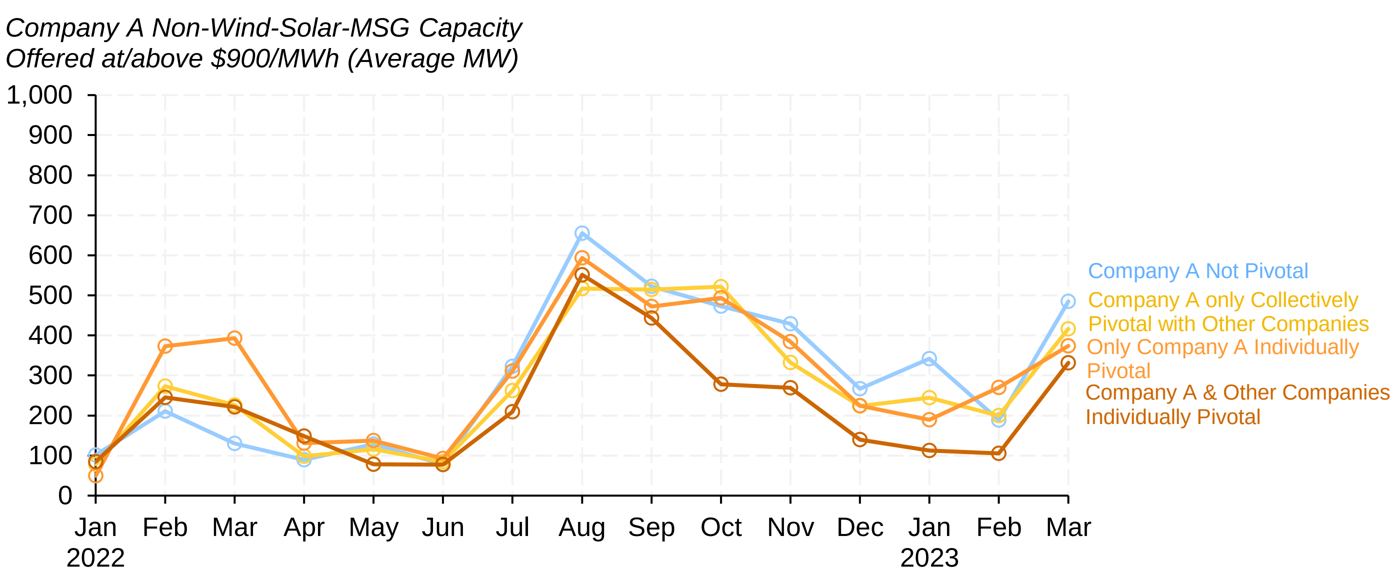


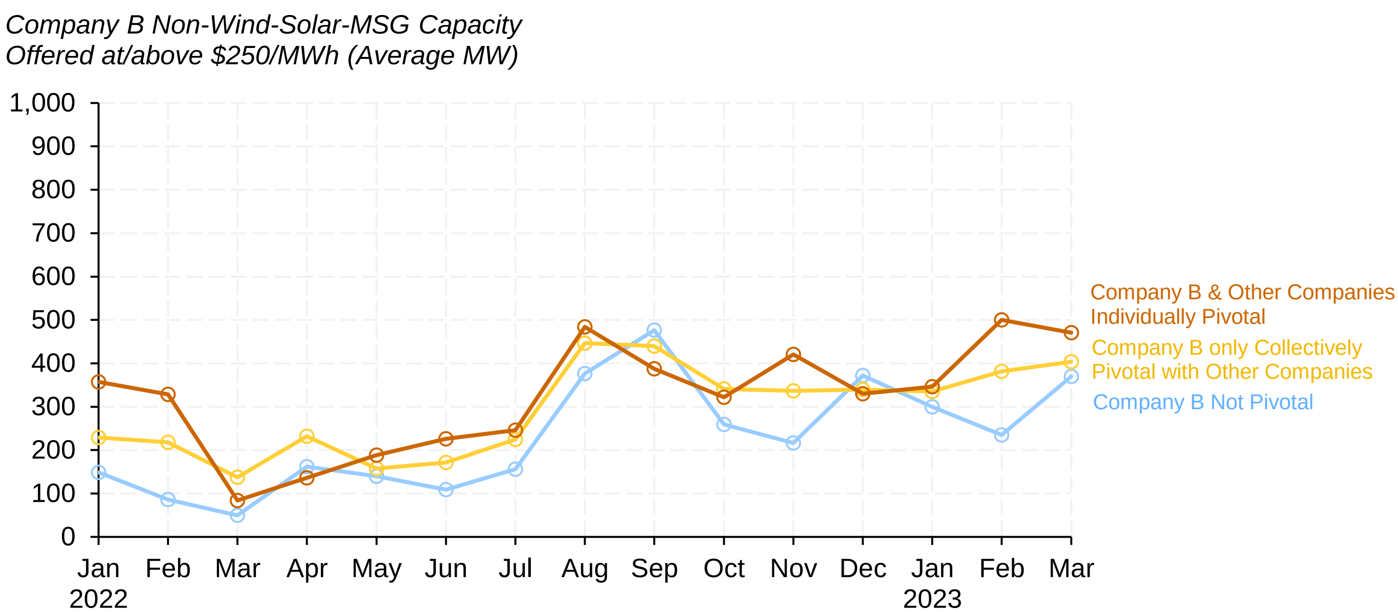
Figure 43: Average Company A non-wind-solar-MSG capacity offered at prices between $900 and the price cap by pivotality condition (January 2022 to March 2023)



While Company A has had a relatively stable pricing strategy since the summer of 2022, the offer prices submitted by Company B have been more often tied to its ability to exercise market power (Figure 44). Apart from September and December, Company B has on average offered more of its non-wind-solar-MSG capacity at higher prices in hours where it was pivotal. In most months since August 2022, Company B has offered more of its non-wind-solar-MSG capacity at prices above $250/MWh in hours where it (and other companies) was individually pivotal, compared to hours where it was only collectively pivotal with other companies.

This pattern of Company B's offer behaviour continued into Q1, including in February, and this contributed to year-over-year increases in the February pool price and markup, despite Company A offering lower amounts of its non-wind-solar-MSG capacity at high prices in that month.

Figure 44: Average Company B non-wind-solar-MSG capacity offered at prices between $250 and the price cap by pivotality condition (January 2022 to March 2023)



1.4 Carbon emissions intensity

In the context of power generation, carbon emission intensity is the amount of carbon dioxide equivalent emitted for each unit of electricity produced. The MSA has published analysis of the carbon emission intensity of the Alberta electricity grid in its quarterly reports since Q4 2021. The results contained in these publications are indicative only, as the MSA has not collected the precise carbon emission intensities of assets from market participants but relied on information that is publicly available. The results reported here do not include imported generation.[23]

[23] For more details on the methodology, see Quarterly Report for Q4 2021.

1.4.1 *Hourly average emission intensity*

The hourly average emission intensity is the volume-weighted average carbon emission intensity of assets supplying the Alberta grid in an hour. Figure 45 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q1 for the past four years.

Figure 45 shows a significant shift of the distribution to the left, indicating a decline in carbon emission intensity over time. This outcome was driven by the conversion of coal-fired generation to natural gas, in addition to increased wind and solar generation. Mean hourly average emission intensities are reported in Table 9, showing year-over-year and quarter-over-quarter comparisons.

Figure 45: The distribution of average carbon emission intensities in Q1 (2020 to 2023)

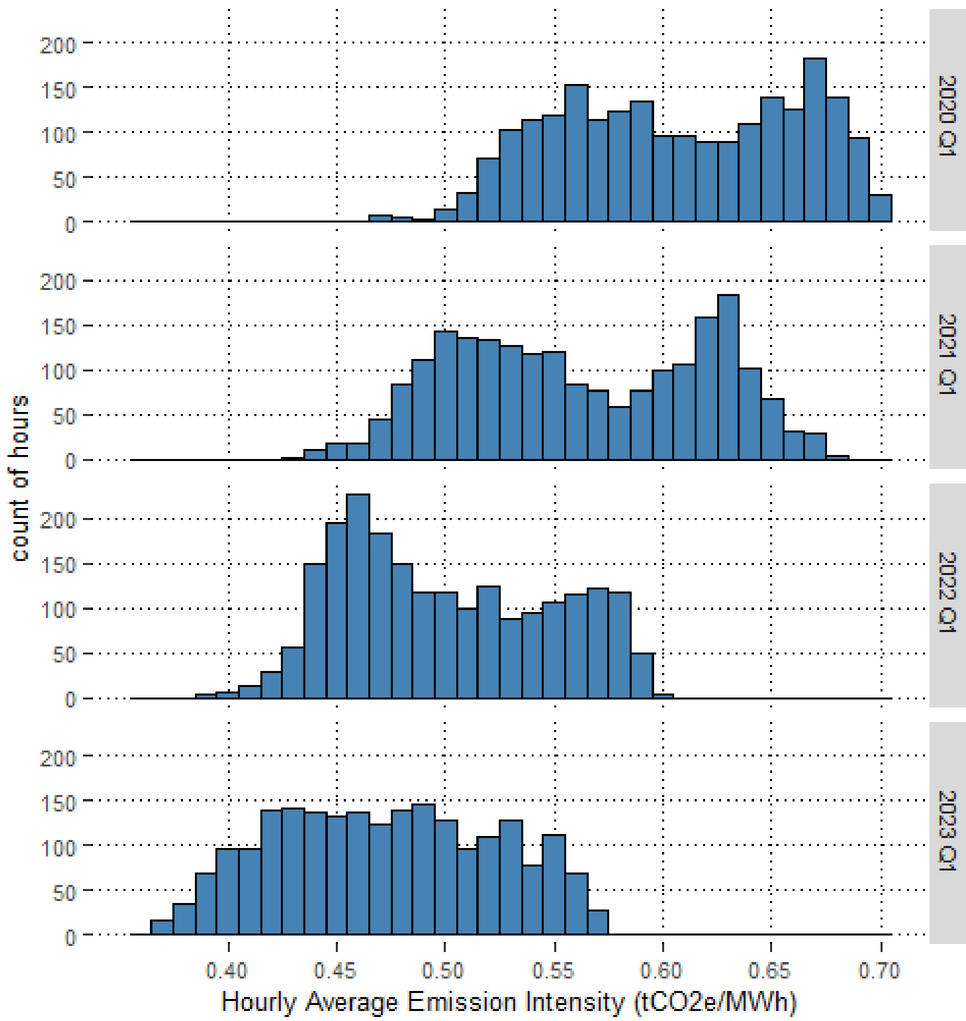


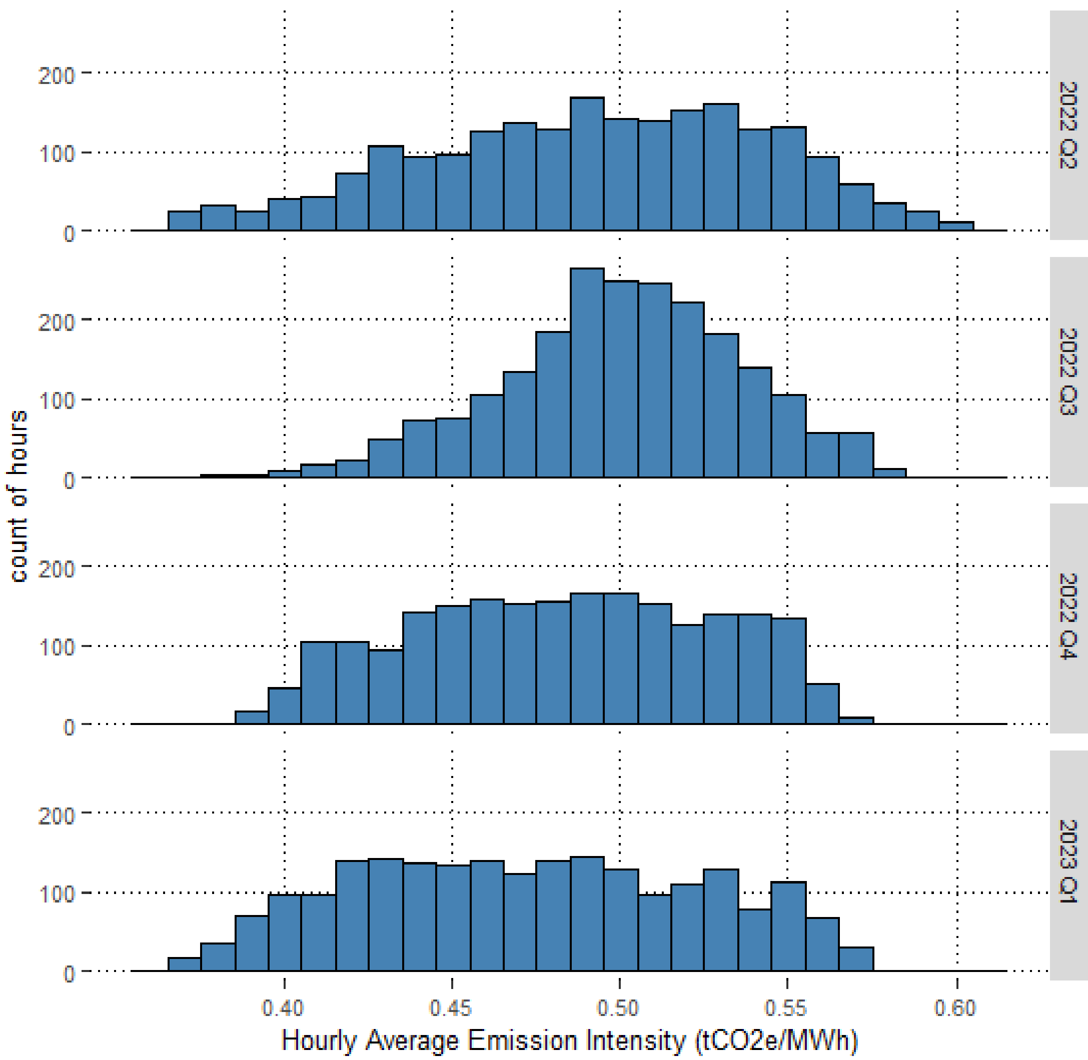
Table 9: The mean of hourly average emission intensities (tCO2e/MWh)

	Mean
2020 Q1	0.61
2021 Q1	0.56
2022 Q1	0.50
2023 Q1	0.47

	Mean
2022 Q2	0.49
2022 Q3	0.50
2022 Q4	0.48
2023 Q1	0.47

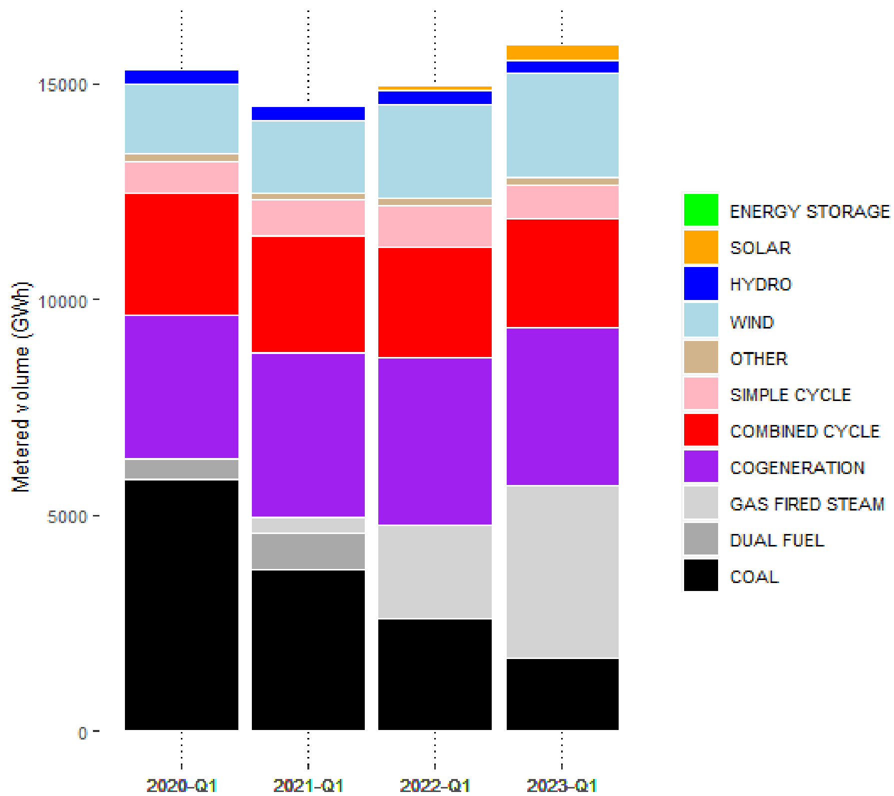
Figure 46 illustrates the distribution of the hourly average carbon emission intensity over the past four quarters. The mean of the distribution has declined slightly from 0.48 tCO2e/MWh in the previous quarter to 0.47 tCO2e/MWh in Q1 2023 (see right of Table 9). The change between the last two quarters reflects the coal-to-gas conversion at Genesee 3 that took place in late 2022.

Figure 46: The distribution of average carbon emission intensities in the past four quarters



The general trends observed in the above distribution figures can be traced in Figure 47, which shows net-to-grid generation volumes by fuel type. Since Q1 2020, there has been a decline in the volume of coal-fired generation, with generation from dual fuel and gas-fired steam assets replacing it. The increase in wind and solar generation driven by growing installed capacity has also contributed to the displacement of coal-fired generation since 2020.

Figure 47: Quarterly total net-to-grid generation volumes by fuel type for Q1 (2020 to 2023)

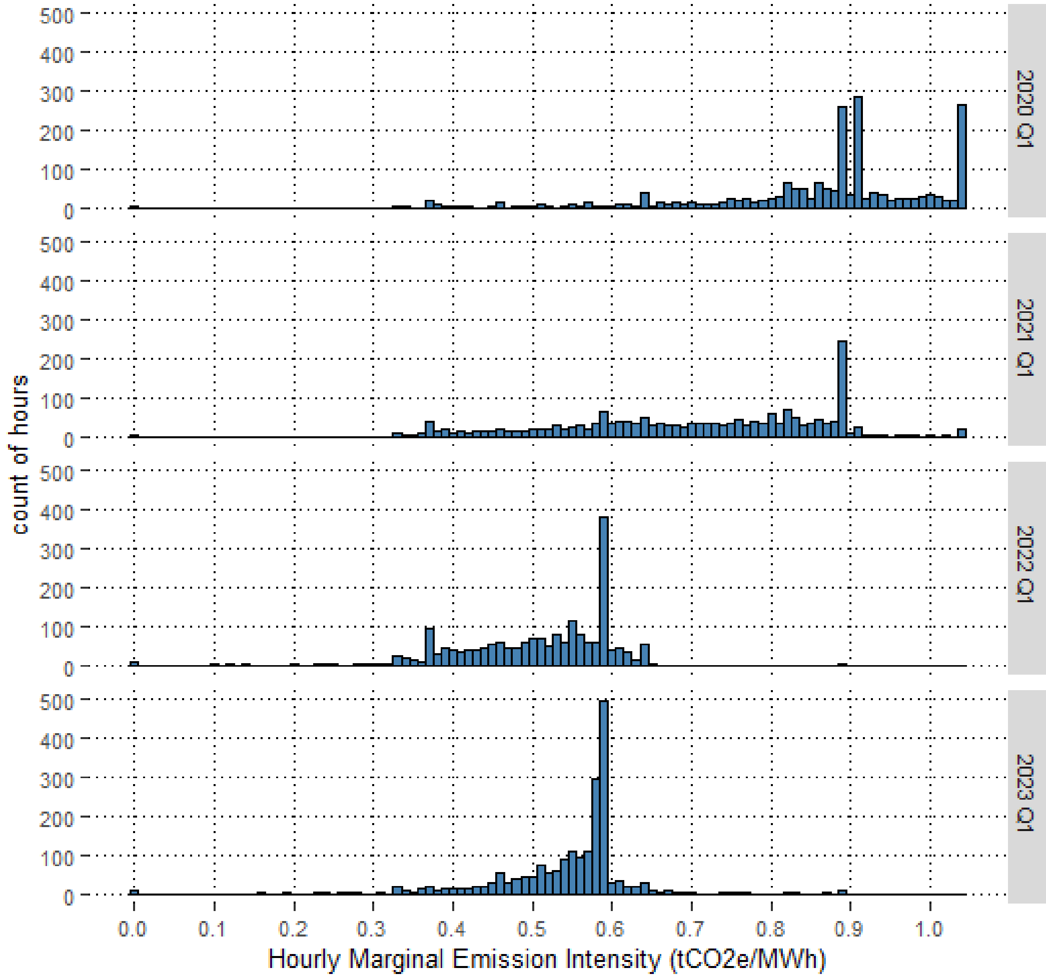


1.4.2 Hourly marginal emission intensity

The hourly marginal emission intensity of the grid reflects the carbon emission intensity of the asset setting the System Marginal Price (SMP) in an hour. In hours where there were multiple SMPs and multiple marginal assets, a time-weighted average of the carbon emission intensities of those assets is used.

Figure 48 shows the distribution of the hourly marginal emission intensity of the grid in Q1 for the past four years. Converted coal assets were setting the price quite often, which was a factor in the spike observed around 0.59 tCO2/MWh in the latter two histograms.

Figure 48: The distribution of marginal carbon emission intensities in Q1 (2020 to 2023)



1.5 Market share offer control

The MSA began publishing market share offer control (MSOC) metrics in its quarterly report in 2021. With this change, the MSA is now including a data file on its website with offer control data, along with tables and charts of interest. Certain tables that were included in previous market share offer control reports can be found in the data file. The data file for market share offer control can be found in the MSA Market Share Offer Control Data file located on the MSA's website under Documents & Reporting > Reports > MSOC.

1.5.1 Requirement to publish offer control report and associated process

The MSA's assessment of MSOC information is required by subsection 5(3) of the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation). Subsection 5(3) states:

> (3) The MSA shall at least annually make available to the public an offer control report that
>
> > (a) shall include the names and the percentage of offer control held by electricity market participants, where the percentage of offer control is greater than 5%, and
> >
> > (b) may include the names and the percentage of offer control held by electricity market participants, where the percentage of offer control is 5% or less.

Details of the process to collect and publish information on offer control to meet the requirements of subsection 5(3) are set out in the MSA's Annual Market Share Offer Control Process (MSOC Process).[24]

1.5.2 Assessment of offer control

In accordance with the MSOC Process, the MSA calculated offer control with data obtained from the AESO for March 31, 2023 HE 18. On April 14, 2023, the MSA requested confirmation of offer control from market participants whose total offer control was calculated as greater than five percent, or for joint ventures that required further clarification. As per section 5(2) of FEOC Regulation, an electricity market participant's total offer control is measured as the ratio of generation capacity under its offer control to the sum of maximum capability of generating units in Alberta.

Generating units are included in the offer control of an electricity market participant (and the denominator) as long as they are registered with the AESO as active assets during the reference hour. Generating units registered as active assets are still required to make offers even if they are not available or are mothballed, and their lack of availability is included in outage data published by the AESO. The total non-dispatchable capacity consists of the total maximum capability of

[24] MSA Annual Market Share Offer Control Process (April 30, 2013)

generating units that do not submit offers into the power pool, such as generating units with a maximum capability less than 5 MW.

The maximum capability of assets used to calculate the denominator may not correspond to the name plate maximum capability that is published on the AESO's Current Supply Demand (CSD) Report. Instead, the denominator uses maximum capability as it is registered with the AESO for the purpose of submitting price-quantity offer pairs.

Table 10: Market share offer control of electricity market participants with greater than 5% offer control between MSOC 2022 and 2023

	Apr/3/2022		Mar/31/2023	
Company	**Control (MW)**	**%**	**Control (MW)**	**%**
TransAlta	2,956	18.5%	3,086	17.0%
Capital Power	2,277	14.3%	2,372	13.1%
Heartland Generation	2,276	14.3%	2,286	12.6%
Suncor	1,182	7.4%	1,632	9.0%
ENMAX	1,452	9.1%	1,462	8.0%
Other	5,509	34.5%	7,001	38.5%
Total Dispatchable	15,652	98.0%	17,839	98.2%
Total Non-dispatchable	319	2.0%	328	1.8%
Grand Total	**15,971**	**100%**	**18,167**	**100%**

Total offer control for participants with greater than five percent MSOC increased from 10,143 MW to 10,838 MW, although this represented a market share decrease from 63.5% in 2022 to 59.7% in 2023. Generation retirements, additions, and maximum capability changes are discussed further in section 1.5.3.

Further details on offer control are provided in the MSA Market Share Offer Control Data file, including:

- a table containing offer control data by the affiliates of electricity market participants,
- a summary table of market share offer control in the current year as well as the previous year, and
- tables and charts illustrating the market share offer control of electricity market participants with offer control over 5%

Figure 49: Dispatchable MW by fuel type (MSOC 2022 and 2023)

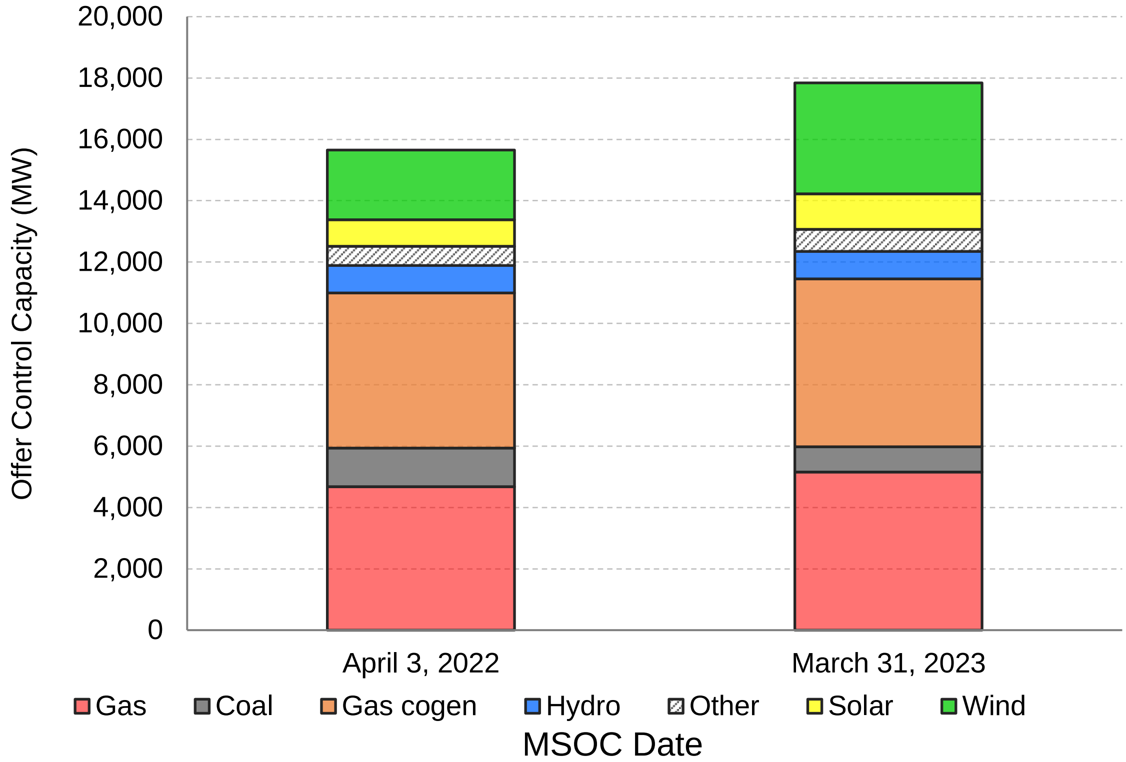
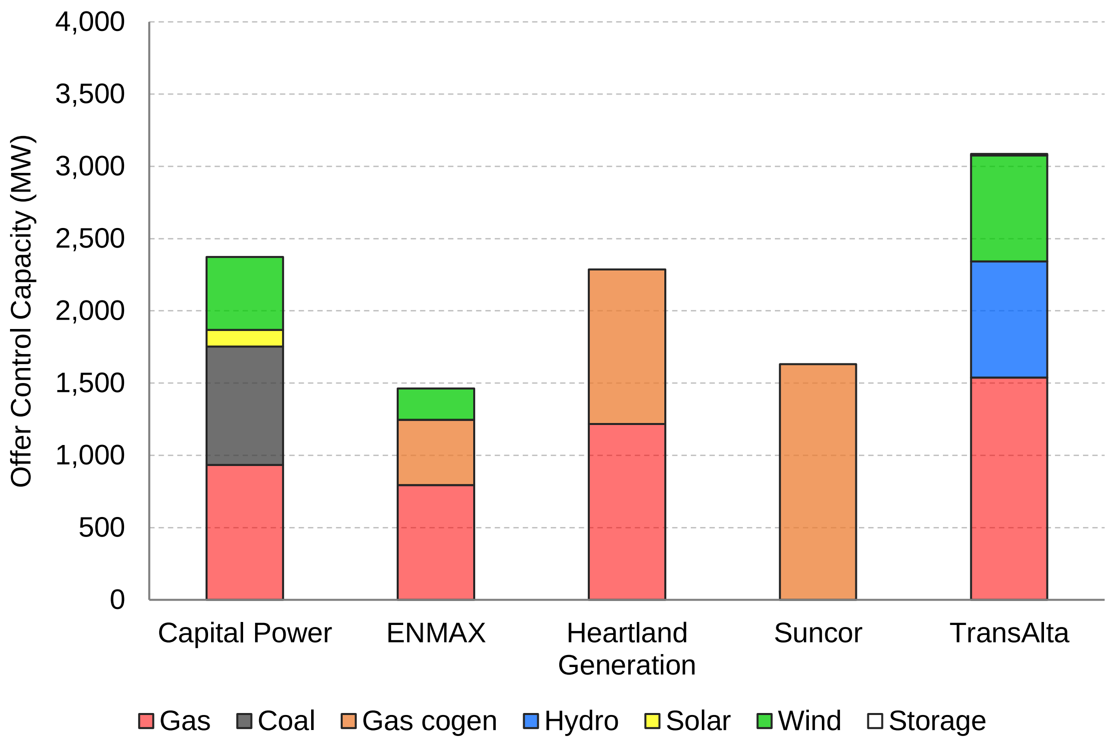


Figure 50: Dispatchable MW by fuel type for market participants with more than 5% offer control



1.5.3 Generation additions, retirements, and maximum capability changes

Since the last MSOC assessment on April 3, 2022:

- no dispatchable generation capacity has retired,
- 1,701 MW of dispatchable capacity was added, and
- existing assets' capacity increased by 486 MW.

Overall, these changes resulted in Alberta's total capacity increasing by 2,196 MW. Specific changes by asset are included in Table 11.

New generation additions were largely comprised of solar and wind generation assets. A total of 1,701 MW of new generation capacity was added, of which 282 MW (17%) was solar generation and 1,349 MW (79%) was wind generation.

The offer capacity of several assets was lowered or increased since the 2022 MSOC assessment. The largest difference was the SCL1 Syncrude #1 cogeneration asset, which increased its offer control value from 100 MW to 510 MW as the asset changed its offer capacity from net to gross.[25] This increase was not a change to the physical capability of the asset, but rather a change in how the asset participates in the energy market. The second largest change was at CMH1 Medicine Hat #1. The MC of the CMH1 asset increased to 299 MW, as an additional 44 MW of generation capacity was connected to the existing asset.[26]

[25] SCL1 Syncrude #1 change in reporting of maximum capability (MC). In August 2022 the offer control for the Syncrude asset was transferred to Suncor.

[26] CMH1 Medicine Hat #1 change in maximum capability (MC) notice

Table 11: Capacity changes between MSOC 2022 and 2023

Asset ID	Fuel Type	2022 (MW)	2023 (MW)	Diff	Date of Change
BLS1	Solar	--	27	27	December 23, 2022
CLY1	Solar	--	41	41	October 5, 2022
CLY2	Solar	--	34	34	October 5, 2022
COL1	Solar	--	23	23	April 5, 2022
CRD1	Solar	--	23	23	July 8, 2022
CRD2	Solar	--	18	18	July 8, 2022
CYP1	Wind	--	196	196	November 8, 2022
CYP2	Wind	--	46	46	October 17, 2022
ERV3	Storage	--	20	20	August 19, 2022
ERV5	Storage	--	20	20	January 16, 2023
FMG1	Wind	--	200	200	August 17, 2022
GDP1	Wind	--	130	130	November 21, 2022
GRZ1	Wind	--	152	152	December 1, 2022
HHW1	Wind	--	145	145	September 30, 2022
HLD1	Wind	--	100	100	November 4, 2022
HRV1	Gas	--	10	10	November 1, 2022
JNR3	Wind	--	109	109	November 15, 2022
LAN1	Wind	--	151	151	November 14, 2022
MIC1	Solar	--	25	25	November 1, 2022
MON1	Solar	--	24	24	June 8, 2022
NMK1	Solar	--	20	20	May 28, 2022
SRL1	Dual Fuel	--	20	20	September 2, 2022
TRH1	Solar	--	25	25	November 1, 2022
VCN1	Solar	--	22	22	September 22, 2022
WHE1	Wind	--	120	120	August 3, 2022
Units Added (Units >=5 MW)		--	**1,701**	**1,701**	
BR5	Gas	385	395	10	October 1, 2022
CAL1	Gas cogen	320	330	10	May 21, 2022
CMH1	Oil/Gas	255	299	44	April 19, 2022
GN2	Coal	400	420	20	October 1, 2022
HRT1	Gas cogen	116	108	-8	July 12, 2022
SCL1	Gas cogen	100	510	410	August 5, 2022
MC Changes (Units >=5 MW)		**1,576**	**2,062**	**486**	
Units <5 MW		182	192	9	
Unchanged Units >=5 MW		14,212	14,212	0	
TOTAL (MW)		**15,971**	**18,167**	**2,196**	

2 THE POWER SYSTEM

The way the power system is utilized is changing over time due to changes in consumer behaviour from the electrification of transport and self-supply of electricity, the continued integration of large-scale variable intermittent generation, the installation of energy storage, and scarcity of historically plentiful network support services. This section of the Quarterly Report will focus on use of the Alberta power system, including the interconnections between Alberta and neighbouring jurisdictions, internal congestion, and pricing and efficiency considerations.[27]

The legislation and regulation governing transmission planning require the AESO to plan for a system that is generally uncongested. As a part of the AESO's planning duties, it is required to forecast load and generation patterns and periodically publish long-term transmission plans that identify current and future needs for a range of possible conditions in Alberta and set out plans to respond. Further, the Alberta Reliability Standards require transmission planning and operational decisions be made such that the power system can withstand the most significant credible contingency occurring, which can be an unexpected outage of a large generator or element of the transmission system.

In this context and given the stochastic nature of demand and (increasingly) generator output, there will be times when the transmission network will operate at less-than-full capacity. Fluctuating supply and demand and the requirement to operate in a state with reserve capacity to carry the power flow that would result from the loss of the next largest element, if applicable, means it will be unusual to observe any portion of the transmission network at full capacity. This should be noted when observing historical real-time power flows.

2.1 HVDC operation and utilization[28]

Alberta has two 500 kV high voltage direct current (HVDC) transmission lines, which have been in operation since 2015. HVDC systems are controllable whereas the rest of Alberta's alternating current (AC) systems are not. Power flows on the HVDC lines are set at specific levels through manual operator action; this is called a power order (or setpoint). This contrasts with the AC components of the transmission network where power flows move through in-service elements automatically at a level determined by the impedance of the entire network. As well, the HVDC lines are not subject to contingencies on the AC system (i.e., the power flow on the lines does not automatically change in response to changes and contingencies on the AC system). However, the loss of a HVDC line may be a relevant contingency for operating the rest of the AC system and in cases where a HVDC line is a part of a next most severe single contingency, it must be operated accordingly. As a result of this feature of HVDC technology, observations of the power

[27] The MSA's mandate includes surveillance in respect of "the supply, generation, transmission, distribution, trade, exchange, purchase or sale of electricity, electric energy, electricity services or any aspect of those activities" (*Alberta Utilities Commission Act* (AUCA), section 39(1)(a)(i)), the conduct of electricity market participants and the Independent System Operator (AUCA, section 39(2)(a)(i) and (iii)), the structure and performance of the electricity market (AUCA, section 39(2)(a)(ii)), and "electricity exchanges on the tie lines connecting the interconnected electric system in Alberta with electricity systems outside Alberta" (AUCA, section 39(2)(a)(x)).

[28] The AESO has indicated that it will soon release a report that develops its own power system utilization metrics.

order and power flows are, in some ways, made simpler because the observation does not need to account for the power flow purposefully operated lower than the physical limits to address the next credible contingency.

Both WATL and EATL are capable of a maximum continuous power flow of 1,000 MW in each direction, and temporary emergency flow of 1,150 MW. The controllability of the HVDC lines anywhere inside this range provide system operators a large degree of flexibility to manipulate power flow in the surrounding AC transmission system. Absent physical operating conditions that require de-rating or outages, decisions regarding the power orders on the HVDC lines are made administratively by the AESO based on the following criteria, in priority order:

1. Maintaining grid reliability. A broad range of criteria are considered, including using the HVDC system to alleviate potential overloads on the surrounding AC transmission system, adjusting voltage profiles near the HVDC substations, and addressing specific islanding scenarios that may arise from outages on the AC transmission system.

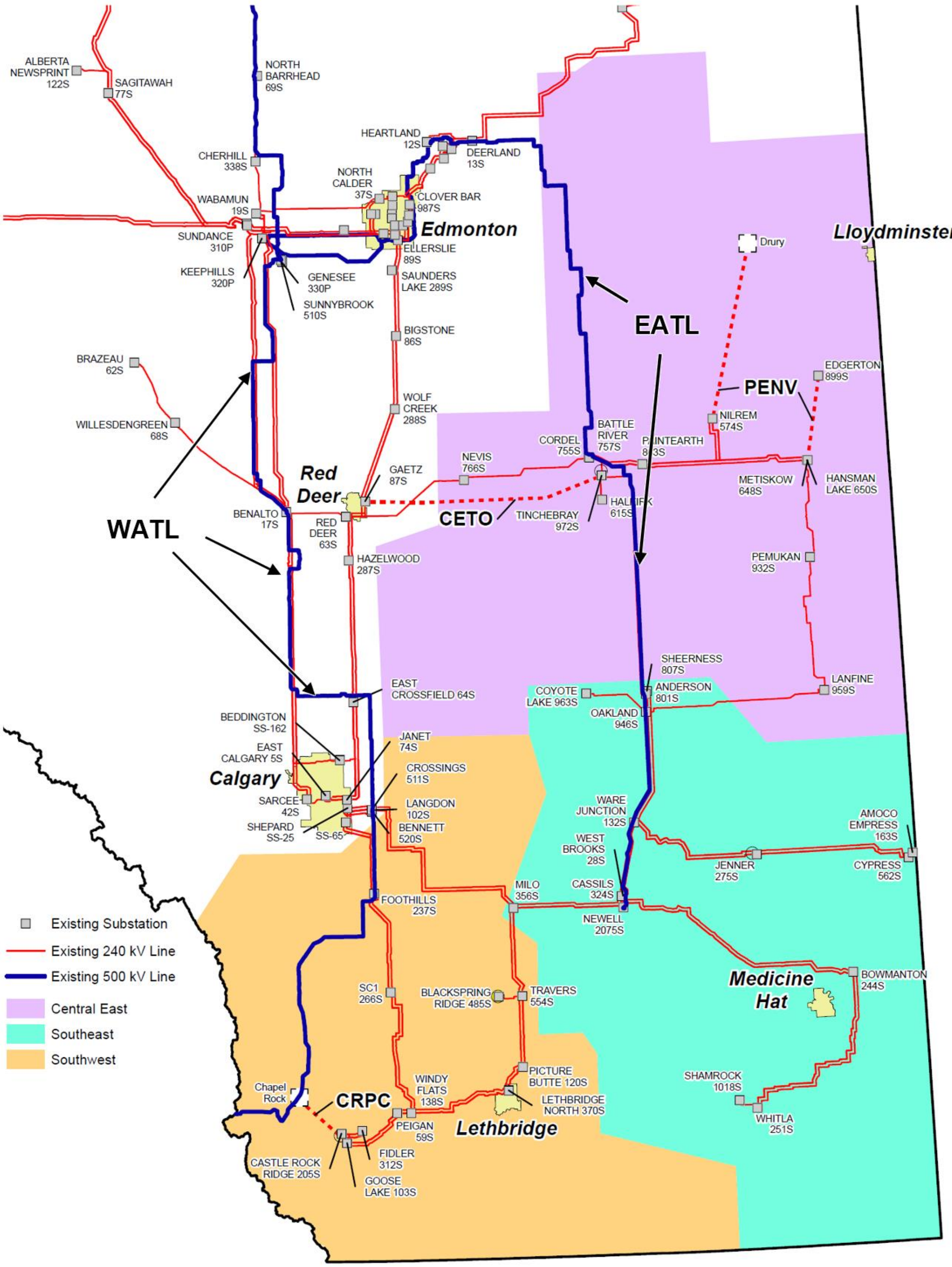
2. Enabling unencumbered dispatch of the energy market by alleviating transmission congestion. Whenever possible, the HVDC system will be set at levels to avoid the use of transmission must-run (dispatching out-of-merit energy) or the issuance of directives to constrain down in-merit energy.

3. Minimizing overall system line losses. Any change in the HVDC power order will have a corresponding impact on the power flows on the surrounding AC transmission system. When the HVDC lines are not used to address the criteria above, they may be set to minimize system line losses that are observed at that time. AESO system controllers have an optimization tool in their energy management system to help determine this level.

Both HVDC lines are situated in the South and Central regions of the AESO’s transmission planning areas. The western Alberta transmission line (WATL or 1325L) has a northern terminal at substation 510s Sunnybrook and a southern terminal at substation 511s Crossings. The eastern Alberta transmission line (EATL or 13L50) has a northern terminal at substation 2029s Heathfield and a southern terminal at substation 2075s Newell. The terminal ends at all four substations house converter transformers that transform power to and from the DC subsystem and the rest of the AC power system.

Figure 51 depicts the geographic location of both WATL and EATL (the bolded transmission lines) in relation to other elements of Alberta’s transmission system and major generation assets.

Figure 51: EATL and WATL



WATL power order dispatch instructions are mainly impacted by:

- intertie activity from the BC-Alberta interconnection;
- wind and solar generation in the South of the province;
- generation levels of the generating stations east of Calgary, especially Shepard generating station;
- load levels in Calgary; and
- generation, load, and voltage levels near the Keephills/Ellerslie/Genesee region southwest of Edmonton.

EATL power order dispatch instructions are mainly impacted by:

- generation levels at the Sheerness generating station;
- increasingly, levels of wind and solar generation in the southeast of the province; and
- load and voltage profiles in the industrial regions northeast of Edmonton.

The development of the HVDC lines date to the mid-2000s, during a period when congestion was increasing over the transmission pathway that connected the generation-heavy region of the Keephills and Genesee power plants to the rest of the of the transmission network, especially the large load centers of Edmonton and Calgary. The HVDC lines were developed in part to address constrained transmission capability to transfer power out from the generators located in the Keephills/Ellerslie/Genesee area. During this time, but prior to the development of and plan for the HVDC lines, various other transmission alternatives were proposed, including a 500 kV AC line connecting the Keephills/Genesee area south to the east Calgary area.

At the time, the anticipated future need for north/south reinforcement of the kind that the HVDC lines provide was predicated on the anticipation that future generation development would appear in the Keephills/Genesee area, load would continue to grow throughout the province, especially in Calgary, and wind generation development would continue in the south areas of the province.

Power system usage since the implementation of the plans made in the mid-2000s materialized somewhat differently than forecasted. Notably:

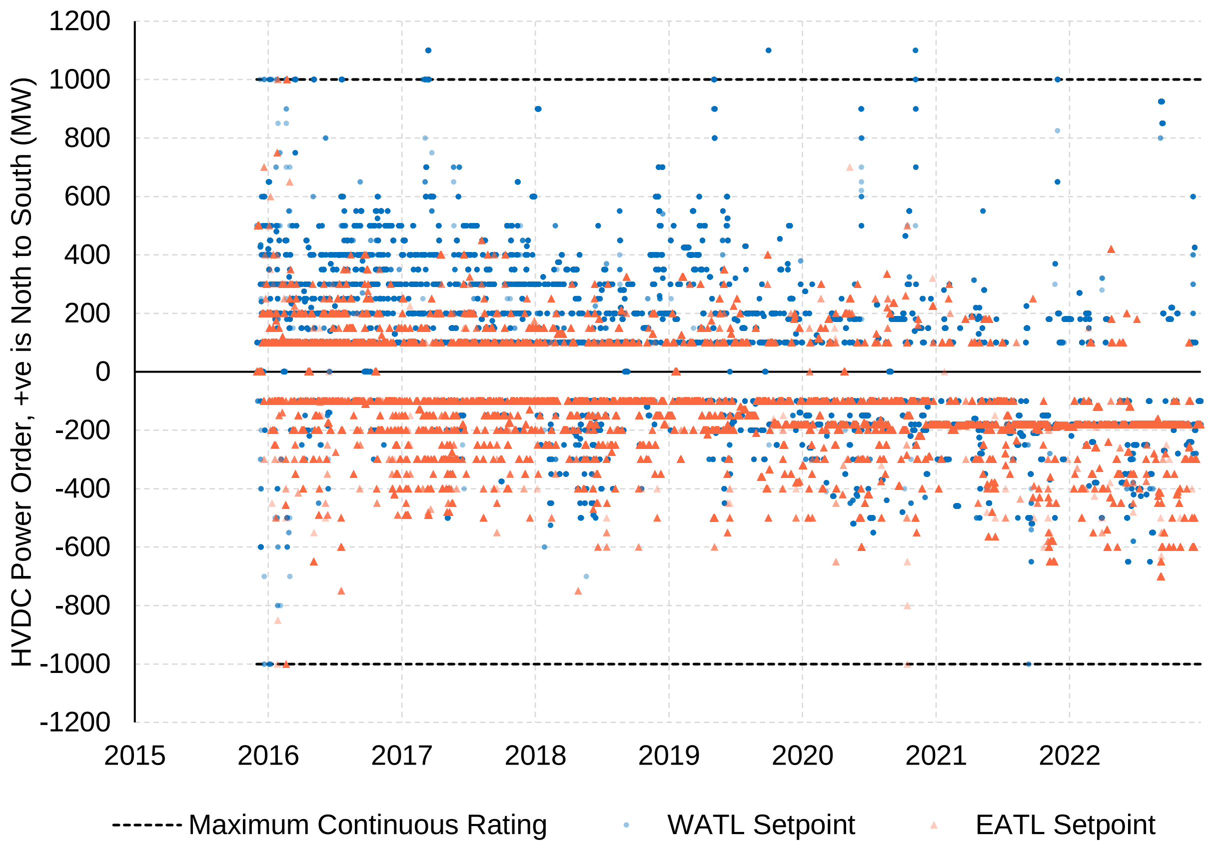
- coal-fired generation in the Keephills/Genesee area has decreased with the retirement of a number of thermal units;
- the Shepard generating facility was developed and constructed in east Calgary area, very close to the southern terminal end of WATL; and

- the development of wind and solar generation assets in the southern area of the province has dramatically increased, and

- the load levels in some regions of the province did not increase by as much as expected.

Figure 52 depicts the historical hourly power orders[29] of both HVDC lines dating from December 1, 2015, during the commission phase for both lines, to December 31, 2022. Positive values represent north to south power flows and negative values represent south to north power flows. When in operation, the HVDC lines are operated outside of plus or minus 100 MW, explaining the very few observations inside this range other than at 0 MW.

Figure 52: Historical HVDC power orders by hour (December 2015 to December 2022)



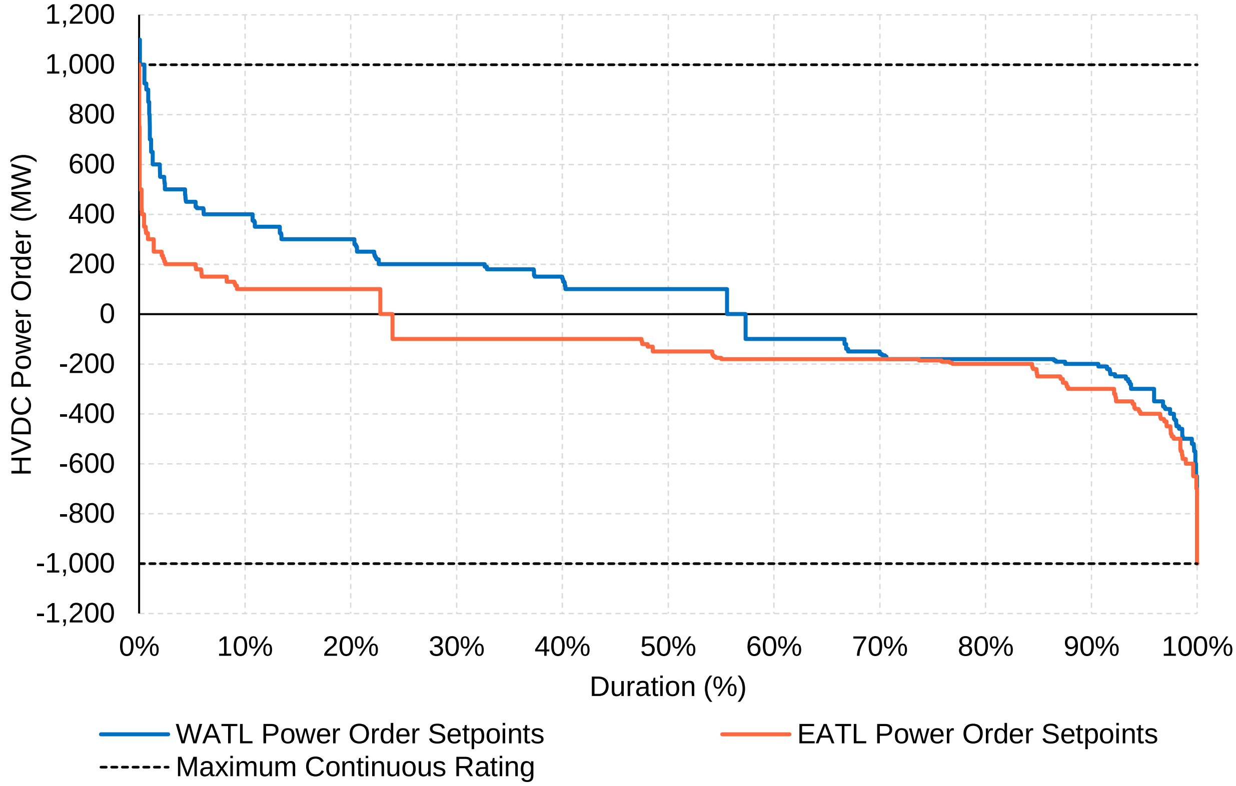
From Figure 52, it appears that HVDC power orders for WATL and EATL vary considerably, especially within ranges inside +/- 400 MW. The power orders also appear to cluster around certain values. These patterns will be explored further in this section.

Figure 53 depicts the historical power orders for WATL and EATL, sorted from highest (north to south) to lowest (south to north). As seen in the figure, WATL has been used to flow power from

[29] This represents 59,820 observations for each of WATL and EATL. Observations are a top-of-hour snapshot and the data do not capture any inter-hour setpoint changes. In this section of the quarterly report, these data are used consistently for all observations and analysis.

north to south more often and with greater magnitude than EATL. In most hours, both HVDC lines were utilized within power order ranges +/- 400 MW of zero.

Figure 53: Historical HVDC power orders, hourly sorted from high to low (December 2015 to December 2022)



When the surrounding AC system is in service and the HVDC lines are not needed to resolve either transmission congestion or system reliability, the HVDC lines are set to optimize system line losses; this is most of the time. Periods of higher usage for both lines are likely representative of hours where the HVDC lines are used to resolve system reliability when elements of the surrounding AC system are out of service.

Notable in Figure 52 and Figure 53 is the frequency for which observations are at either +100 MW or -100 MW. As indicated in Table 12, WATL has experienced a period in 2018/2019 when operation of the WATL at the deadband was more frequent, reaching over one third of the hourly observations in these years. Since the 2018/2019 period, the power orders on WATL have shifted away from the usage on these dead bands. Similarly, EATL has seen its flows increase from frequent deadband operation in the year of its commissioning to a decline in operation at the deadband levels around 2021. In recent times, especially in 2022, both HVDC lines have experienced all-time lows in operation at their respective +/- 100 MW dead band levels. This suggests that flows on the HVDC lines have increased over time for EATL and since 2018 for WATL.

Table 12: Count and percentage of hours for WATL and EATL at +/- 100 MW

	WATL		EATL	
	Number of hours	Percentage of hours in the year	Number of hours	Percentage of hours in the year
2016	1,608	18%	5,192	59%
2017	2,267	26%	4,232	48%
2018	3,329	38%	4,857	55%
2019	3,186	36%	3,761	43%
2020	2,441	28%	3,066	35%
2021	1,564	18%	1,148	13%
2022	788	9%	559	6%

Figure 54 and Figure 55 depict duration curves for WATL and EATL, respectively, for the years of 2017, 2019, 2021, and 2022. Years are differentiated by colour in accordance with the legend. Most power orders span between -600 MW and + 600 MW. As the charts indicate, both WATL and EATL have trended steadily towards a more negative (south to north) flow through the years of their operation. For WATL this is likely a result of the observed timeframe capturing a period of high imports (close to the southern terminal end of WATL), increasing wind and solar generation, and declining generation capacity in the KEG region (close to the northern terminal end of WATL). For EATL, this is likely a result of increased wind and solar generation in the southeast region of the province and load patterns in the heartland region near Edmonton. Notably, power orders on WATL did not continue the trend towards more northerly flow in 2022, compared to 2021.

Figure 56 depicts the combinations of power orders of WATL against EATL. The hourly observations have been bucketed into 50 MW increments and observation counts are counted in each cell and also expressed as a colour gradient. Stylized illustrations of the Province of Alberta and arrows depicting the directional flow of WATL and EATL are in the corner of each quadrant of the chart.

Figure 54: WATL power order duration curve (2017, 2019, 2021, and 2022)

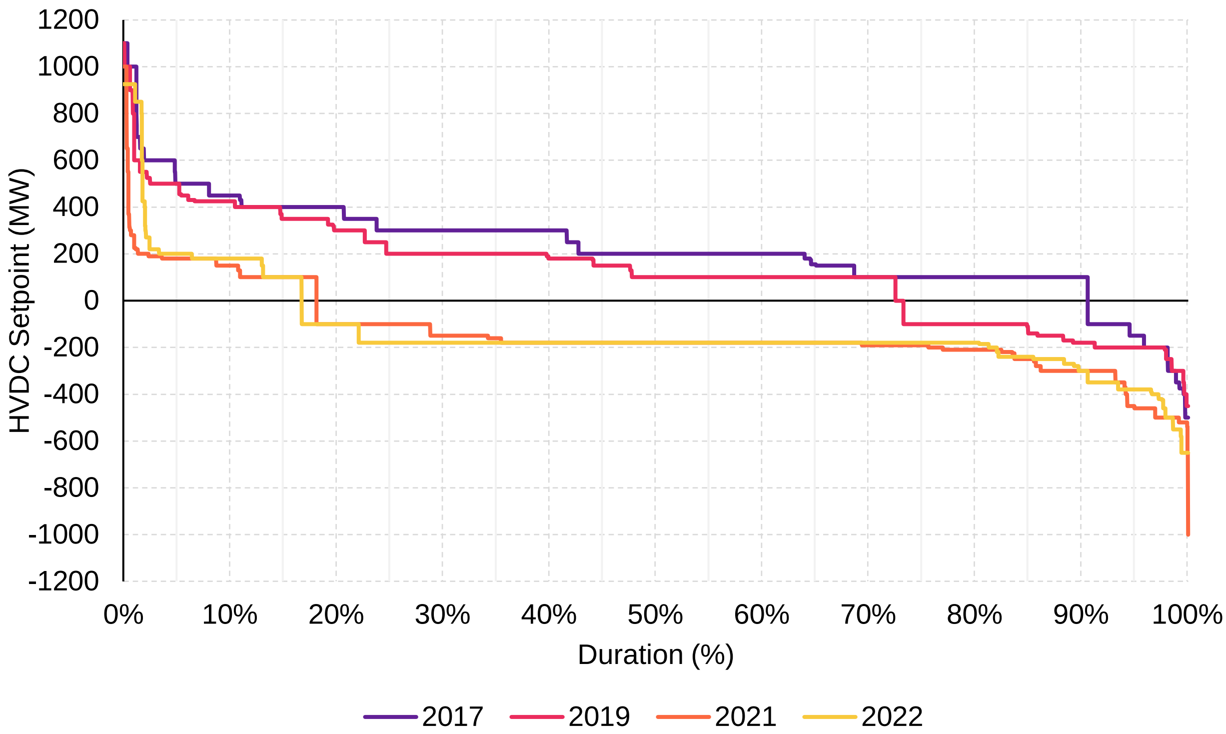


Figure 55: EATL power order duration curves (2017, 2019, 2021, and 2022)

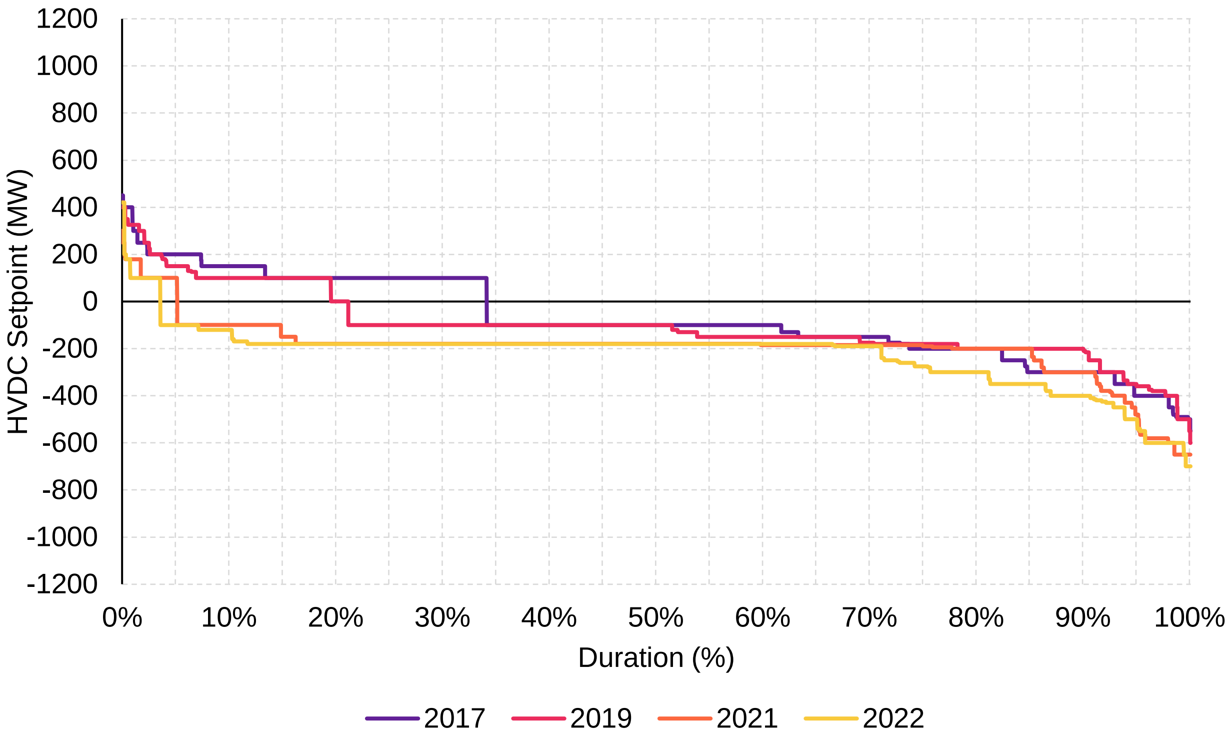


Figure 56: Combinations of historical HVDC power orders (December 2015 to December 2022)

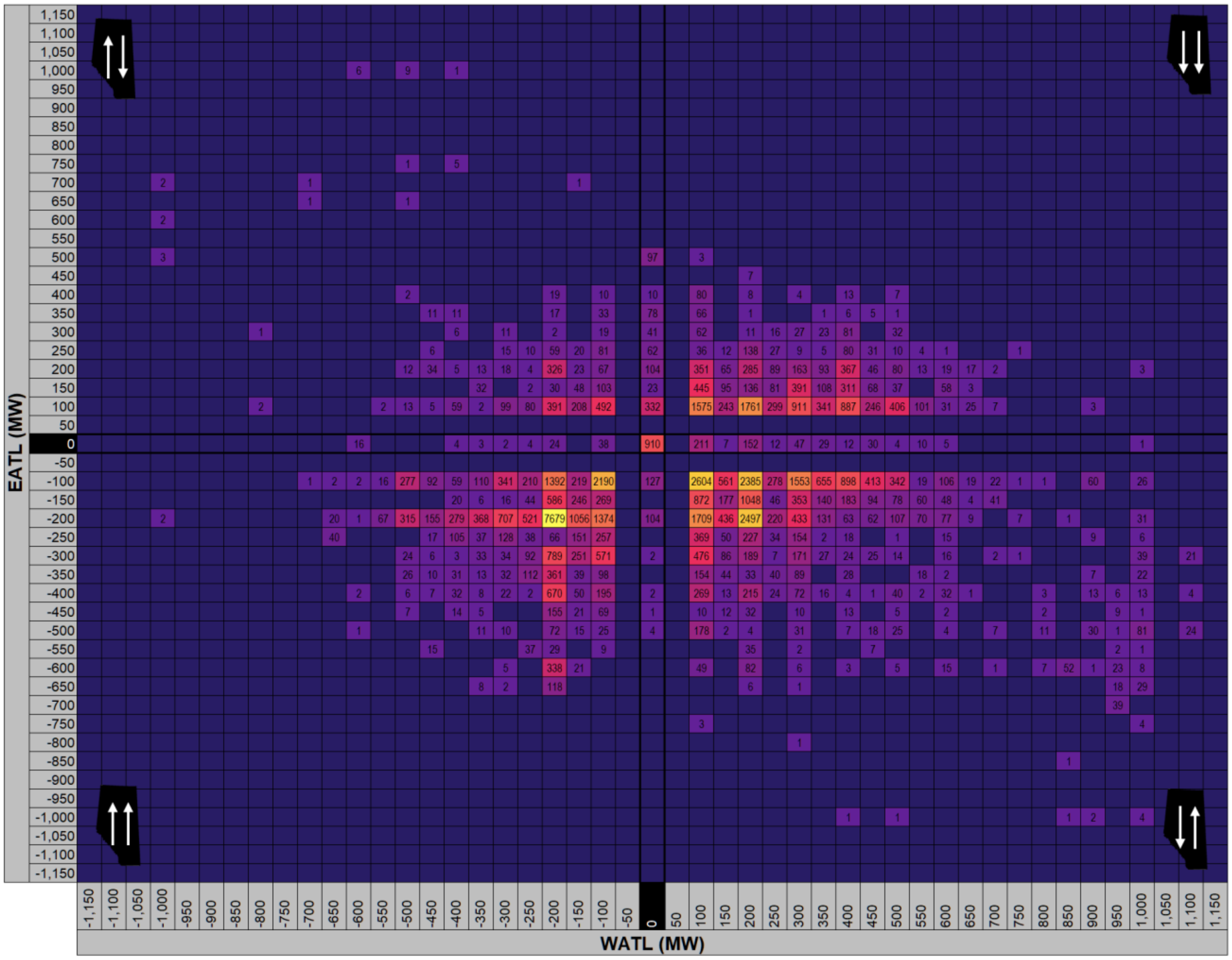


Table 13 sets out the percentage of time that each HVDC line flows in one direction compared to the other, or is not flowing at all. The data suggests that though both lines run roughly parallel to each other and the 240 kV backbone between the major load centers of Edmonton and Calgary, the power orders for EATL and WATL are somewhat independent of each other.[30] Viewing the substation terminal ends of each HVDC line as a source or sink asset, and considering that in most hours, the HVDC power order is inside of +/- 400 MW, it is likely that the power order of one HVDC line has a small and limited impact on the power order of the other HVDC line. It is more likely that the HVDC power orders are determined independently and most impacted by the factors highlighted at the beginning of this section. If the trend of usage for both WATL and EATL continues to a more south to north flow as indicated in Figure 54 and Figure 55, one can expect future observations to move towards the bottom/left quadrant of Figure 56.

[30] WATL and EATL power orders are generally independent of one another when dealing with constraints and correlated when they are being used to minimize line losses.

Table 13: Direction of power flows on EATL and WATL (December 2015 to December 2022)

		WATL			
		South to north	Zero	North to south	EATL total
EATL	North to south	3.9%	1.2%	17.4%	22.5%
	Zero	0.1%	1.5%	0.8%	2.4%
	South to north	38.1%	0.4%	36.6%	75.1%
	WATL total	42.1%	3.0%	54.8%	100.0%

Another notable observation from all figures in this section is the frequency at which either the EATL or WATL power orders are set at either -180 MW or -185 MW, especially in more recent years. For both HVDC lines, these settings are often used to address a specific case of maintaining system reliability; that of high voltage conditions on the AC system near the HVDC substations, most often at the northern terminal ends. These conditions often arise when there is low load in the Edmonton area, resulting in high voltage conditions combined with offline generating units in the Keephills/Genesee region resulting in little reactive power capability from available online generation. Under these conditions, the HVDC system is used to optimize voltage levels near their respective substation terminal ends. The following table depicts the frequency of observations in 2021 and 2022 for both EATL and WATL when each line is set at -180 MW or -185 MW.

As Table 14 indicates, in recent periods, the majority of power orders for EATL since 2021 and WATL in 2022 are set at -180 MW or -185 MW. This observation is likely part of the explanation for the decrease of in power orders at the -100 MW to +100 MW deadband highlighted in Table 12. As the power system continues to experience sustained high voltage in the Keephills/Genesee area because of low load and a lack of generator availability in the area to reduce reactive power and therefore voltage, WATL and EATL are expected to be used at these power order levels to manage voltage in the area for some time.

Table 14: Count and percentage of hours for WATL and EATL set at -180 MW or -185 MW

	WATL		EATL	
	Number of hours	Percentage of hours in the year	Number of hours	Percentage of hours in the year
2021	2,968	34%	5,141	59%
2022	5,181	59%	4,815	55%

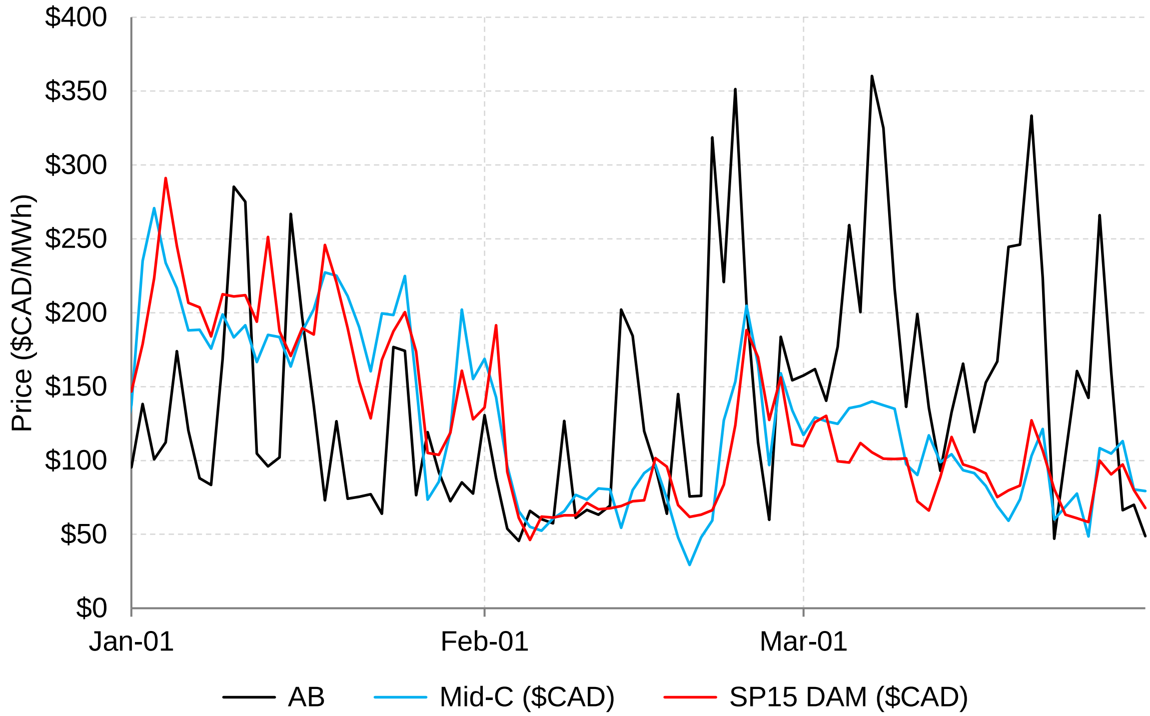
The operation of the HVDC lines is changing because of the evolving power system, including the addition of more wind and solar generation capacity. The HVDC lines are used to manage constraints, minimize line losses, and provide voltage support to the underlying AC system.

2.2 Imports and exports

Interties connect Alberta's electricity grid directly to those in British Columbia (BC), Saskatchewan (SK), and Montana (MATL), with the intertie to BC being the largest. For reliability purposes, the AESO treats BC and MATL as one intertie (BC/MATL) because any trip on the BC intertie will also cause MATL to trip offline. These interties indirectly link Alberta's electricity market to markets in Mid-C and California.

Figure 57 illustrates daily average power prices in Alberta, Mid-C, and California over Q1. As shown, prices in Mid-C and California were often higher in January. Power prices in Mid-C have been increased by low hydro levels this year.[31] Prices in Mid-C and California generally tracked natural gas price movements, which saw declines across the quarter. Beginning in mid-to-late February, Alberta power prices were higher and more volatile.

Figure 57: Daily average power prices in Alberta, Mid-C, and SP15 in California (Q1 2023)



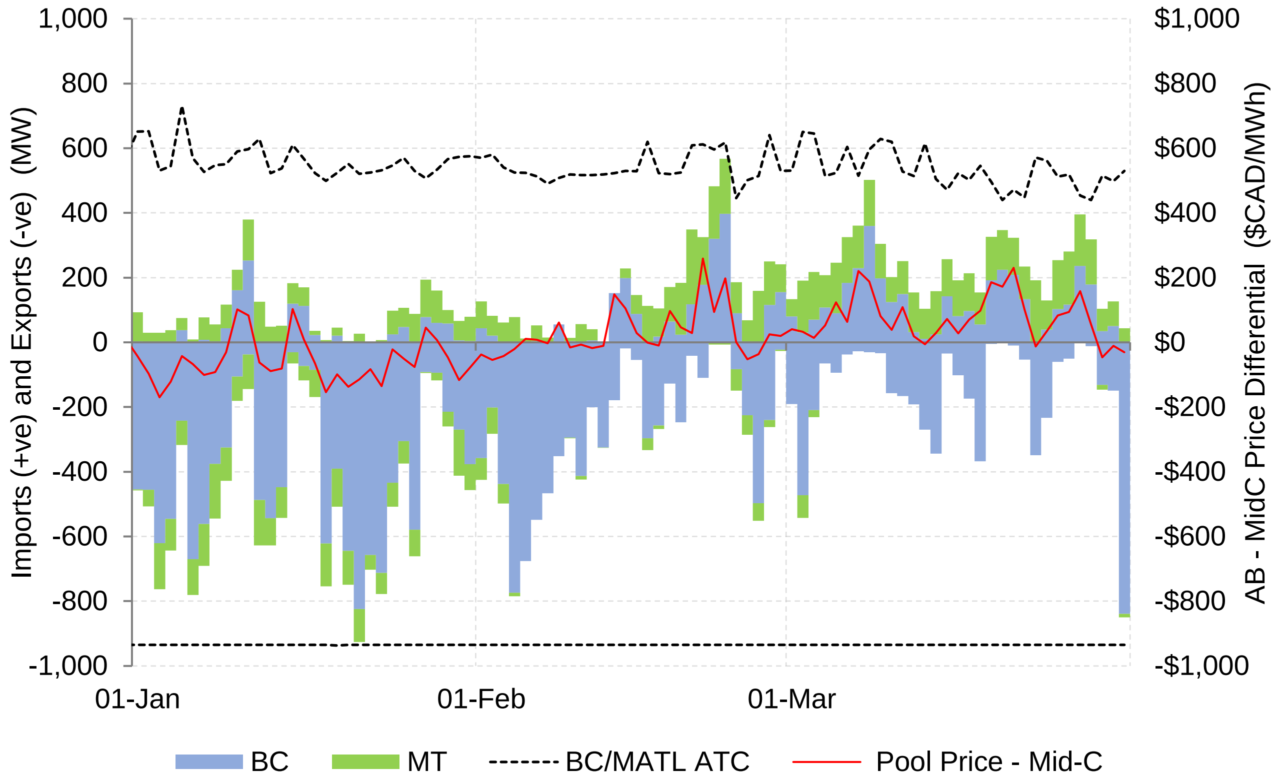
The price differential across different markets is the driver of intertie flows. As expected based on these observations, more exports were scheduled earlier in the quarter, with periods of higher imports in the latter half.

Figure 58 illustrates the daily average of import and export volumes on the BC and Montana interties and the daily average price differential between Alberta and Mid-C. Export flows were

[31] Northwest River Forecast Centre, Water Supply Forecasts, see Dalles Dam and Mica Dam for example

BC Government, Snow Survey and Water Supply Bulletin, April 1, 2023 significant throughout January and into the first half of February when Alberta pool prices were often lower than prices in Mid-C. In the second half of the quarter, when pool prices increased above prices in Mid-C, import volumes increased.

Figure 58: Daily average import and export volumes on BC/MATL, and the average price differential between Alberta and Mid-C (Q1 2023)



A key aspect of the power flows to and from Alberta is the difference between available transfer capability (ATC) for imports and exports. The AESO limits BC/MATL import ATC so that the Alberta grid can handle the contingency event of the BC/MATL interties tripping offline, as well as the most severe single contingency (MSSC) inside Alberta. The calculation of import capability is based on the amount of Load Shed Service for imports (LSSi)[32] and contingency reserves (CR) available, as well as the net offers and forecasted demand for a given hour. On the other hand, export ATC is more reflective of the physical capability of the BC/MATL transmission lines. Consequently, import ATC is generally lower and more variable than export capability (Figure 58).

Figure 59 shows a scatterplot of the price differential between Alberta and Mid-C, and the net flow for each hour in Q1. In certain hours the net import offers on BC/MATL were above import ATC, meaning the interties were import constrained. In other hours, the net export bids were above export ATC, meaning the interties were export constrained. As shown, there was more variability

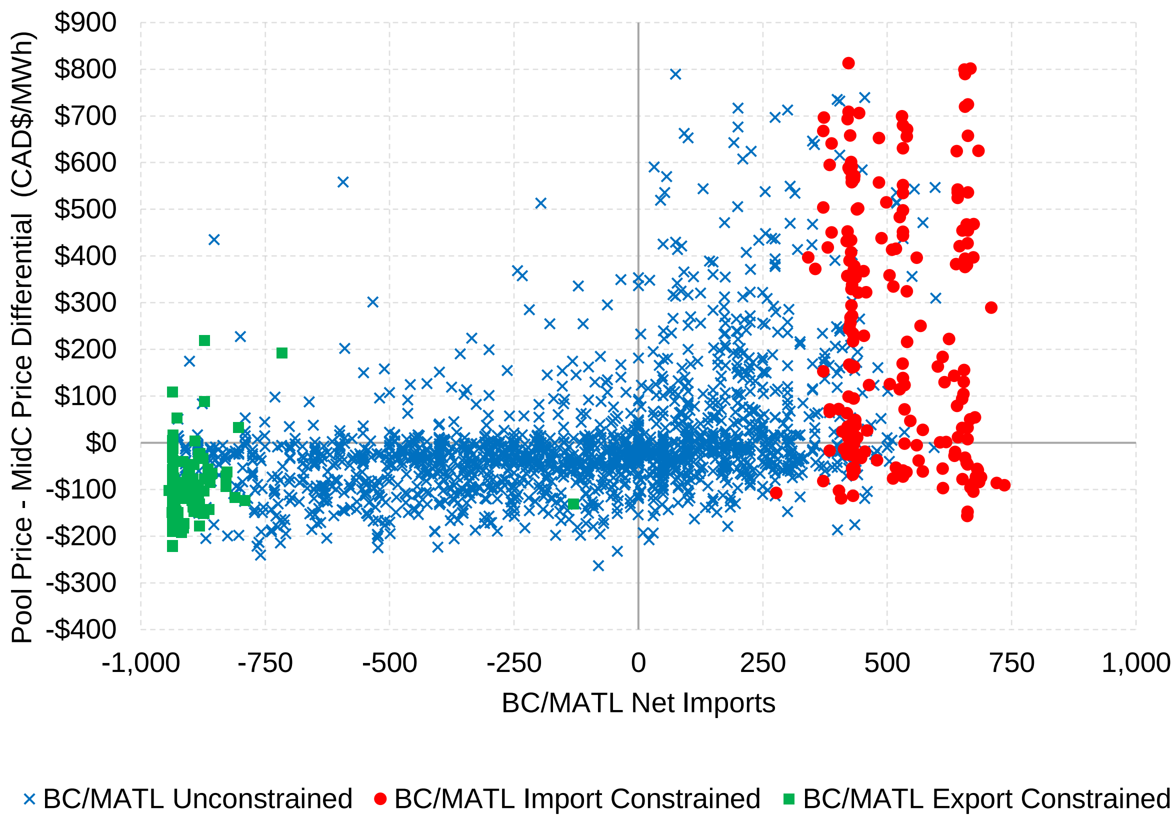
[32] LSSi is a reliability product developed to increase import intertie capability and is contracted between the AESO and load providers who agree to instantaneously shed consumption in the case of a sudden loss of imports to manage under frequency.

in flows during hours of import constraints relative to hours of export constraints. Economic flows are generally in the top right and bottom left segments based on the realized price differential (without consideration of transmission costs or other factors).

During hours of net imports on BC/MATL in Q1, the BC/MATL intertie was import constrained 22% of the time. In these hours the average price differential between Alberta and Mid-C was CAD$233/MWh, and the average import ATC was 524 MW.

In hours of net exports on BC/MATL in Q1, the BC/MATL intertie was export constrained 18% of the time. In these hours the average price differential was negative CAD$103/MWh, and ATC was consistently 935 MW. In some constrained hours realized flows did not fully use the ATC. This can occur because of curtailments by external balancing authorities, or because of e-tag submission issues. For example, on Figure 59 there is a BC/MATL export constrained hour where net exports were only 130 MW, which was a result of e-tags not being submitted on time.

Figure 59: Alberta and Mid-C differential and net BC/MATL flows (Q1 2023)



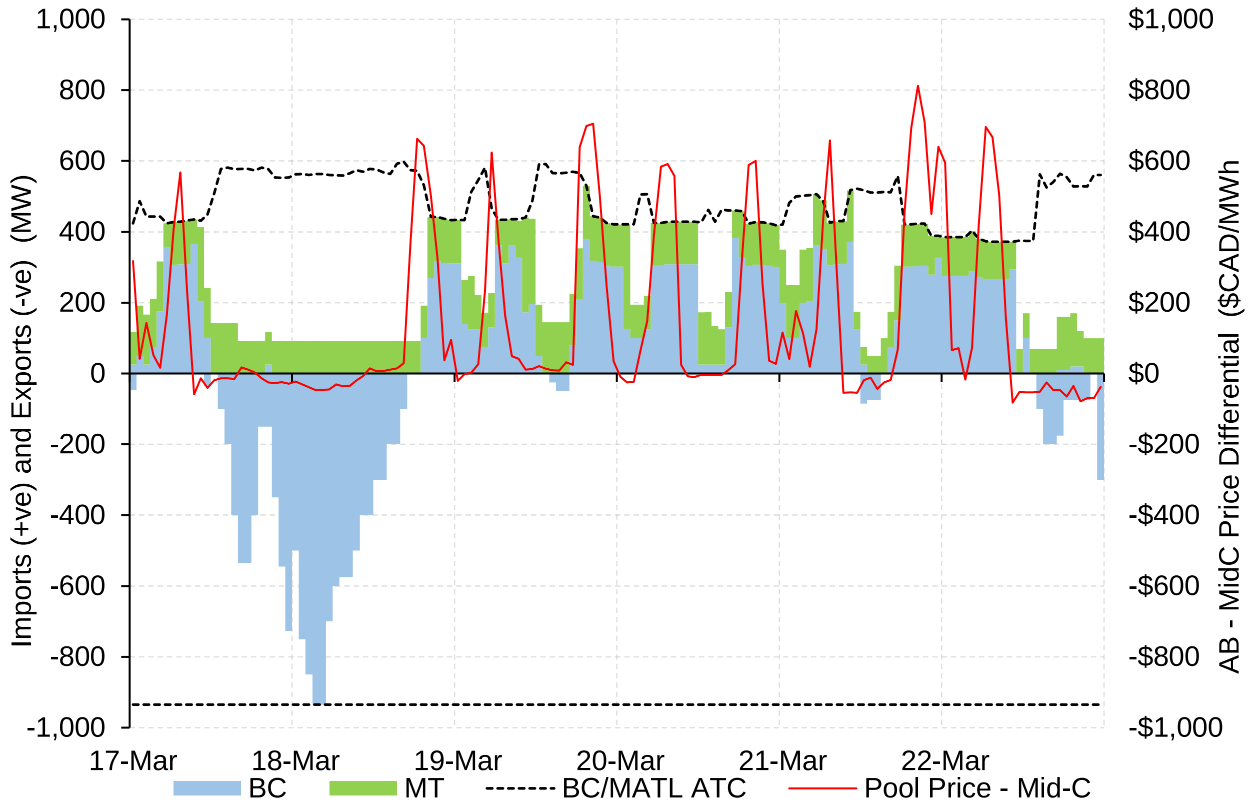
In hours when the pool price was more than CAD$100/MWh higher than prices in Mid-C, the utilization rate of import capacity was 54%. Price volatility observed over the quarter and the timing requirements of interchange scheduling can impact overall import utilization. Similarly, in hours where the pool price was more than CAD$100/MWh lower than prices in Mid-C, the utilization of export ATC was 57%.

In some hours heavy export flows occurred despite pool price settling well above price in Mid-C. For example, on February 16 in HE 14 net exports on BC/MATL were 594 MW although the pool price was $644/MWh and Mid-C price was CAD$86/MWh. Pool prices were elevated during this hour due to lower-than-expected solar generation, prevailing energy offers, and high exports.

Similarly, on January 6 in HE 17, there were net exports of 852 MW even though the realized pool price was $629/MWh and Mid-C prices were CAD$194/MWh. In this instance, for the preceding twenty-four hours the Mid-C price was CAD$100/MWh higher on average, resulting in high exports.

During some high-wind and low pool price hours in Alberta there were exports on the BC intertie and imports along MATL. For example, this occurred on March 17 and 18 (Figure 60). This was likely the result of high wind supply also occurring in the Montana region at the same time.

Figure 60: Hourly import and export volumes on BC/MATL (March 17 to 22, 2023)



Effective March 15, 2023, the AESO increased the amount of LSSi required for a given BC/MATL import ATC. Figure 60 shows BC/MATL flows for March 17 to 22. During this period imports were constrained in 61 hours due to elevated pool prices. The average import ATC during these import-constrained hours was 427 MW according to the new LSSi requirements table, given the available LSSi and realized load level. Earlier in March, import ATC averaged 598 MW during hours of import constraint, or 171 MW higher. The revised LSSi tables[33] reduce import ATC on BC/MATL, leading to more constrained hours and lower import supply.

Figure 61: Hourly BC/MATL import ATC fundamentals (March 17 to 22, 2023)

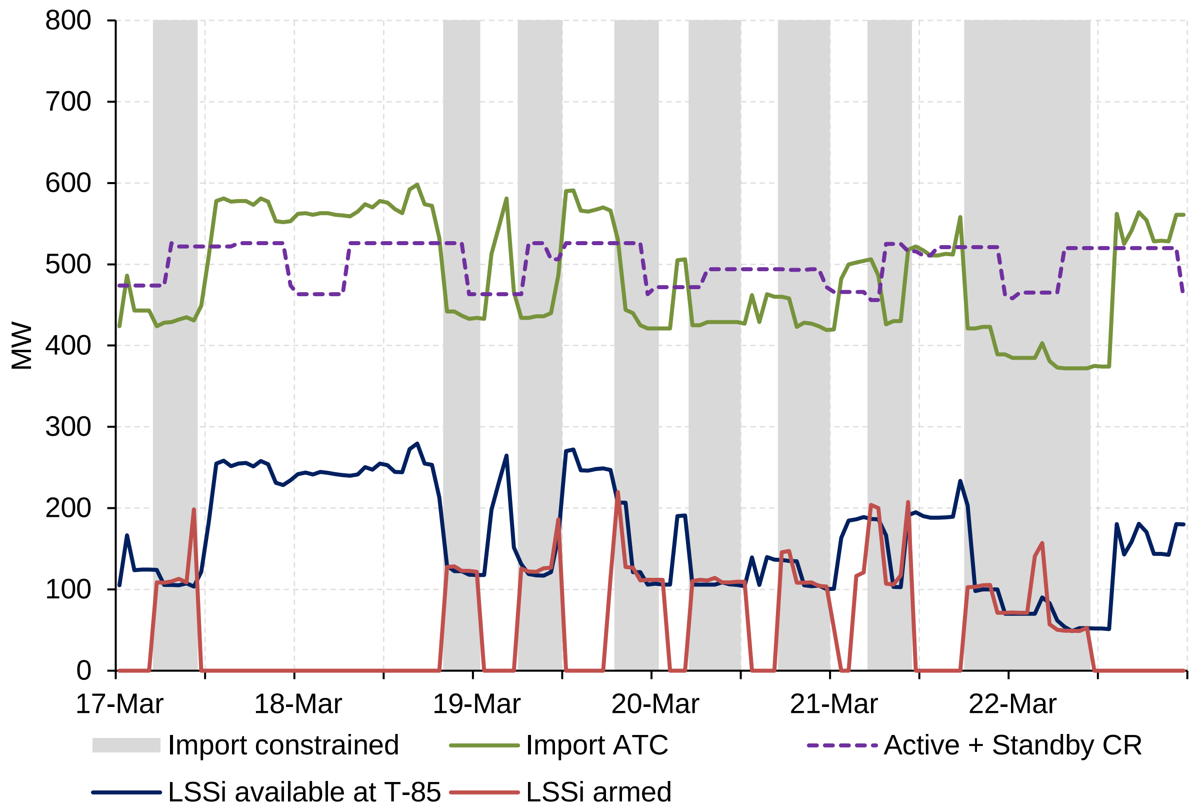


Figure 61 shows the import ATC on BC/MATL over March 17 to 22, 2023 along with factors that determine the calculation of import ATC. As discussed earlier, import offers, LSSi, contingency reserves, and AIL demand are the factors which determine ATC for any given hour. As shown in this figure, offered volumes of LSSi at T-85[34] and import ATC moved in step during this period. The volume of LSSi offered often declines when pool prices are forecast to be high, which can reduce import ATC during hours when higher imports would be expected.

The process for calculating import ATC under normal operating conditions is:

- At T-85, net offers are assessed against forecasted load for the applicable settlement interval to determine LSSi requirements:
    - If no LSSi is required for net import offers based on the normal table, import ATC is set at:

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[33] ID #2011-001R - Information Document Available Transfer Capability and Transfer Path Management

[34] The time that is 85 minutes prior to the start of the applicable settlement interval.

    - The maximum amount of import ATC permitted for 0 MW of LSSi under expected demand + LSSi available at T-85

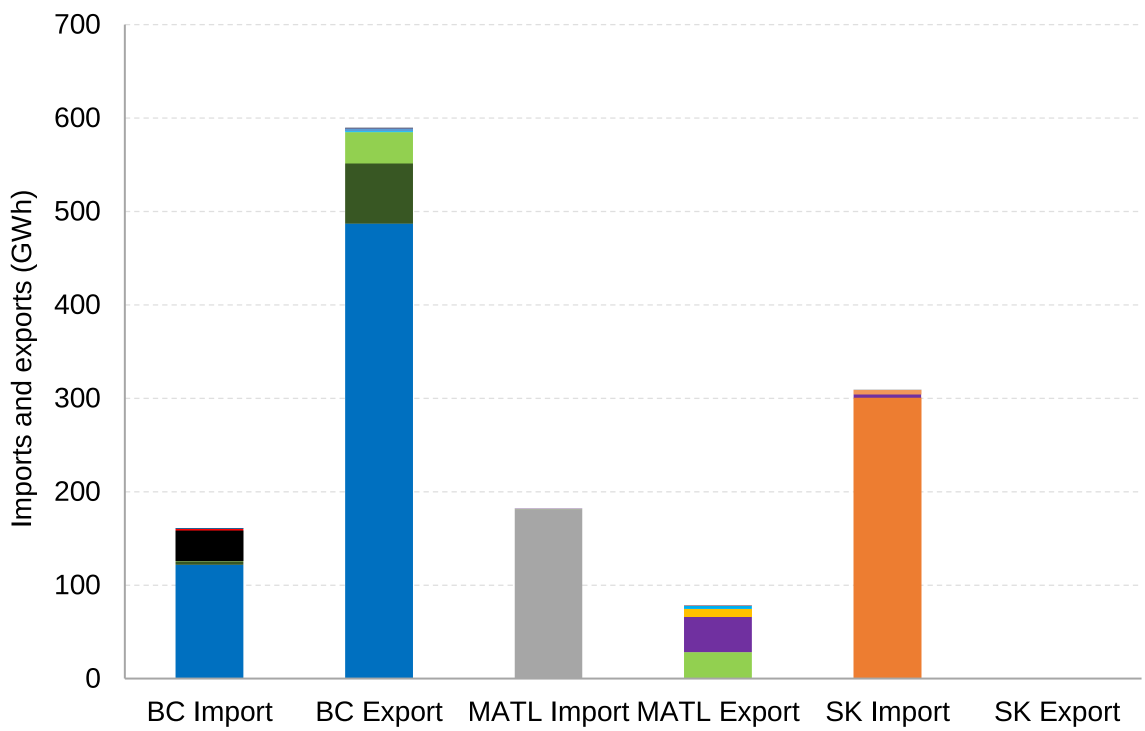
  - If LSSi is required for net offers, and available LSSi can partially or completely cover the amount required, the AESO will arm the LSSi deemed necessary and import ATC is set at:
    - The maximum amount of import ATC permitted for 0 MW of LSSi under the expected demand + LSSi available at T-85

- Following T-85, if there are changes lowering the amount of LSSi available, import ATC is typically impacted in the case where LSSi can only partially cover the amount required for given net offers, and import ATC is set at:
  - The original total ATC calculated at T-85 minus the deficit LSSi volume from the LSSi provider's restatement

- Following T-85, if there are changes increasing amount of LSSi available for the applicable settlement interval, there is typically no change in import ATC.

Figure 62 illustrates total import and export volumes in Q1 by intertie and market participant. As shown, exports to BC were the main source of flow in Q1. Total imports were 652 GWh, and total exports were 668 GWh, meaning that there was a total net export of 16 GWh across the quarter. Flows on all three interties were largely scheduled by market participants that hold long-term firm transmission service.

Figure 62: Total import and export volumes by intertie and market participant (Q1 2023)



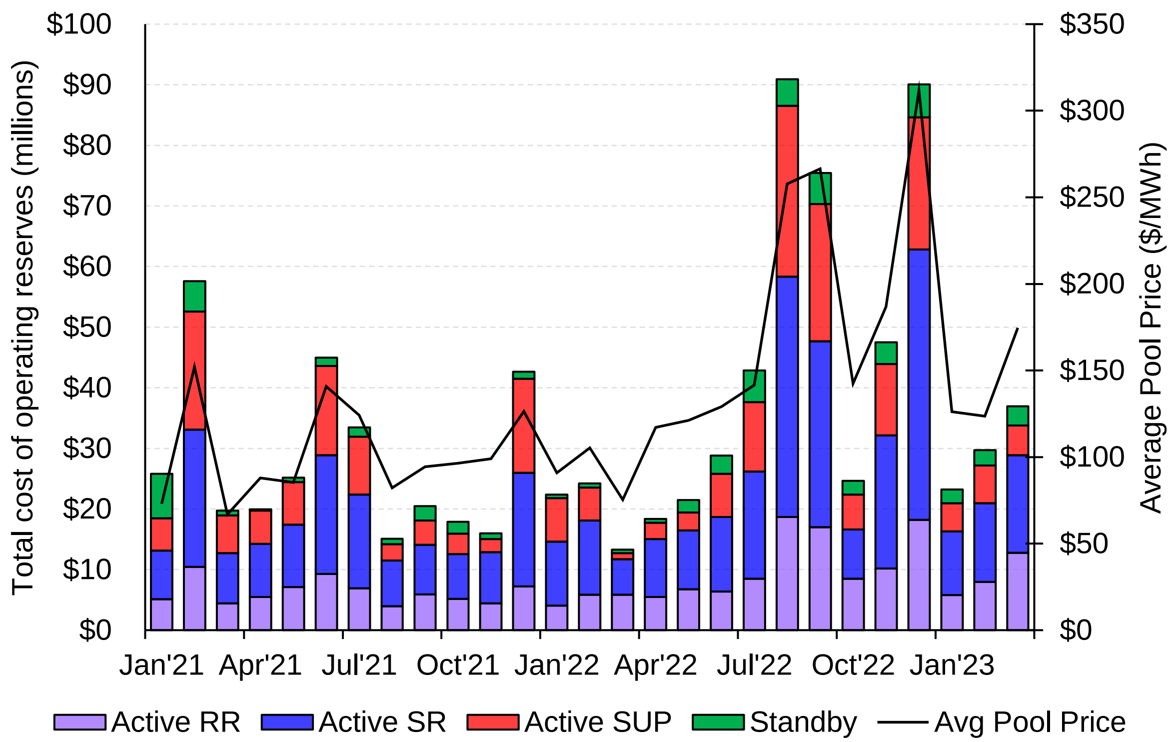
3 OPERATING RESERVE MARKETS

There are three types of operating reserves (OR) that AESO system controllers use when there is an unexpected imbalance or lagged response between supply and demand: regulating reserve, spinning reserve, and supplemental reserve. Regulating reserve (RR) provides an instantaneous response to an imbalance of supply and demand. Spinning reserve (SR) is synchronized to the grid and provides capacity that the system controller can direct in a short amount of time when there is a sudden drop in supply. Supplemental reserve (SUP) is not required to be synchronized but must be able to respond quickly if directed by the system controller.[35] These products are bought by the AESO through day-ahead auctions.

3.1 OR costs and volumes

Total quarterly OR costs fell in Q1 to $89.9 million, compared to $161.2 million in Q4 2022. The primary driver of lower OR costs was lower pool prices. OR costs and pool prices are positively correlated because the opportunity cost of providing OR is usually foregoing a margin from the sale of energy. This is particularly true for active OR products since active prices are indexed directly to pool price. Figure 63 shows the total cost of OR products and average pool price by month.

Figure 63: Total cost of active and standby reserves and average pool price by month (January 2021 to March 2023)



[35] For more detailed information, see [AESO: Operating Reserve]

From January to February, despite the small $2.63/MWh fall in pool price, total OR costs rose from $23.2 million to $29.7 million due to higher equilibrium prices for active OR while standby costs remained similar. This may be due to participants adjusting their expectations following a period of lower pool prices in early Q1 relative to late 2022.

Table 15 shows the quarterly average cost of active OR products. Pool price increased by $52.02/MWh year-over-year but OR costs increased by less than that, which indicates lower equilibrium prices in all three active products compared to Q1 2022. Increased supply in the supplemental market continues to moderate the effect of higher pool prices. This can be explained in part by participation from loads, for which cost is a function of interrupted consumption rather than forgone revenues from the energy market.

Table 15: Average cost ($/MWh) of active OR products (Q1 2022 and 2023)

Product	Q1 2023	Q1 2022	Q1 2023 - Q1 2022
Regulating	$92.35	$54.91	$37.44
Spinning	$75.92	$50.12	$25.81
Supplemental	$30.62	$23.84	$6.78
Avg. pool price	**$142.00**	**$89.98**	**$52.02**

Table 16 shows the average received prices for active OR products in Q1. The average received price differs from average cost because average cost is volume weighted.[36] Average received prices are slightly lower, indicating that OR prices tend to be higher when more volume is procured. Also shown are the percentages of hours in which the discount for OR exceeds the pool price, resulting in a $0/MWh received price. Supplemental reserve earned a received price of $0/MWh in 87% of hours in Q1.

Table 16: Average received price ($/MWh) and percentage of $0/MWh received prices for active OR products (Q1 2023)

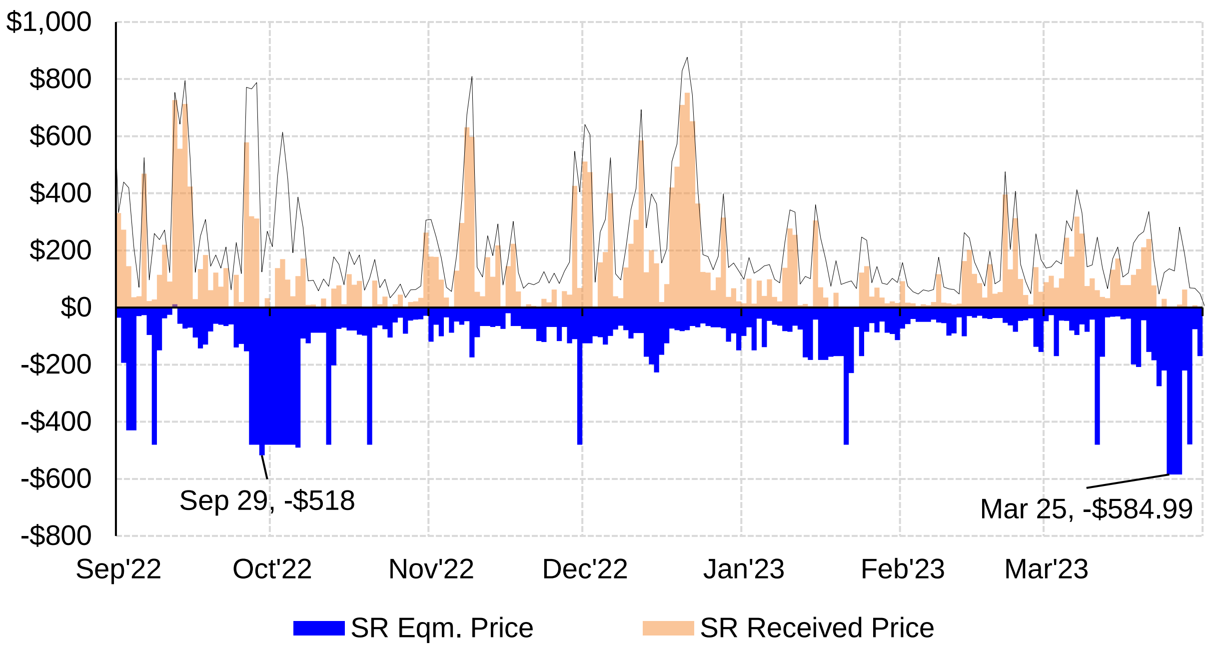
Product	Average received price	Percentage of $0/MWh received prices
Regulating	$90.41	29%
Spinning	$72.91	38%
Supplemental	$28.14	87%

Spinning reserve continued to see strong participation from battery storage assets, due in part to the addition of the eReserve5 Hughenden (ERV5) asset. Figure 64 shows the active on-peak equilibrium price for spinning reserve since September 2022. On March 25, 26, and 27, the on-

[36] The data underlying Table 16 uses volume weighting to determine hourly weighted-average received prices for hours with concurrent super-peak and on- or off-peak regulating reserves.

peak equilibrium price for spinning reserve reached a new all-time low of -$584.99/MWh, associated with an unadjusted offer price of -$1209.99/MWh. This was lower than the previous record of -$518/MWh set on September 29, 2022 and continues the trend observed in previous quarters of participants submitting offers below -$999.99/MWh.

Figure 64: Daily active on-peak spinning reserve equilibrium price, received price, and pool price (September 1, 2022 to March 31, 2023)



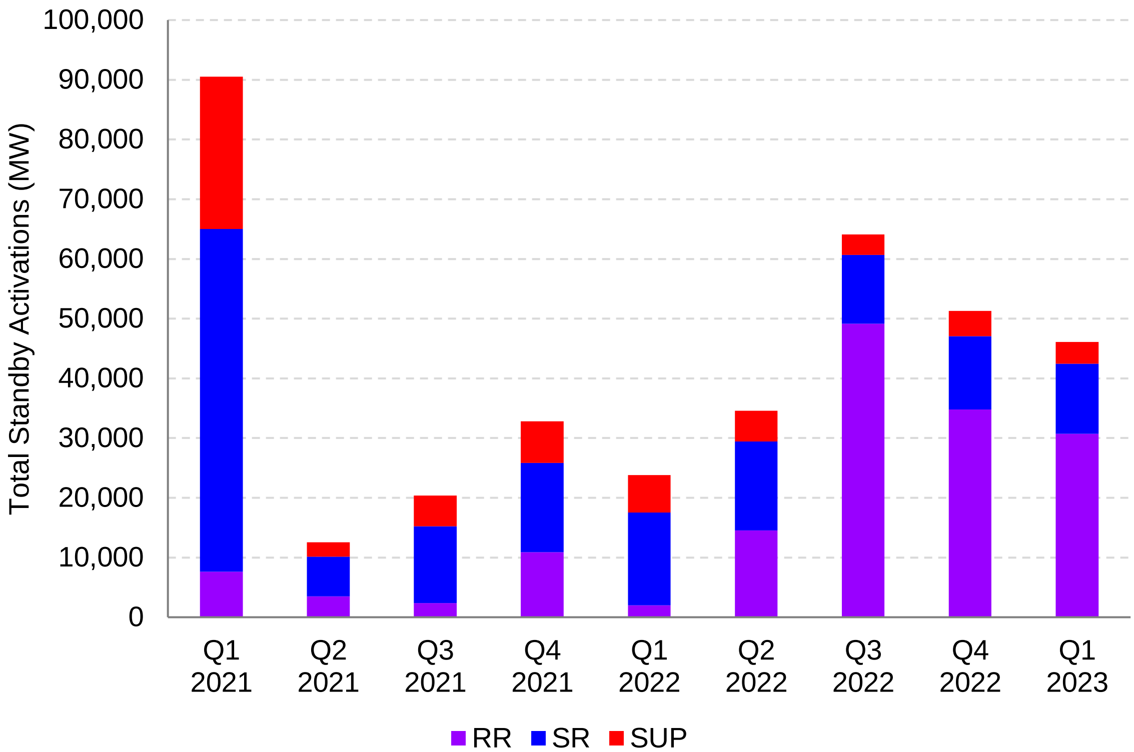
3.2 Standby activations

Figure 65 shows that total standby reserve activations fell to 46,084 MW in Q1 from 51,321 MW in Q4 2022. This was primarily driven by lower regulating reserve activations.

Standby regulating reserve activations occur when active regulating reserve volumes are insufficient. This can be driven by an asset's inability to provide active regulating reserves, when more regulating reserve is needed to manage volatility of renewable generation, or because of merit order changes at the top of an hour.

Significant volumes of regulating reserve continue to be curtailed due to transmission constraints affecting a single asset.

Figure 65: Total quarterly standby reserve activations (Q1 2021 to Q1 2023)



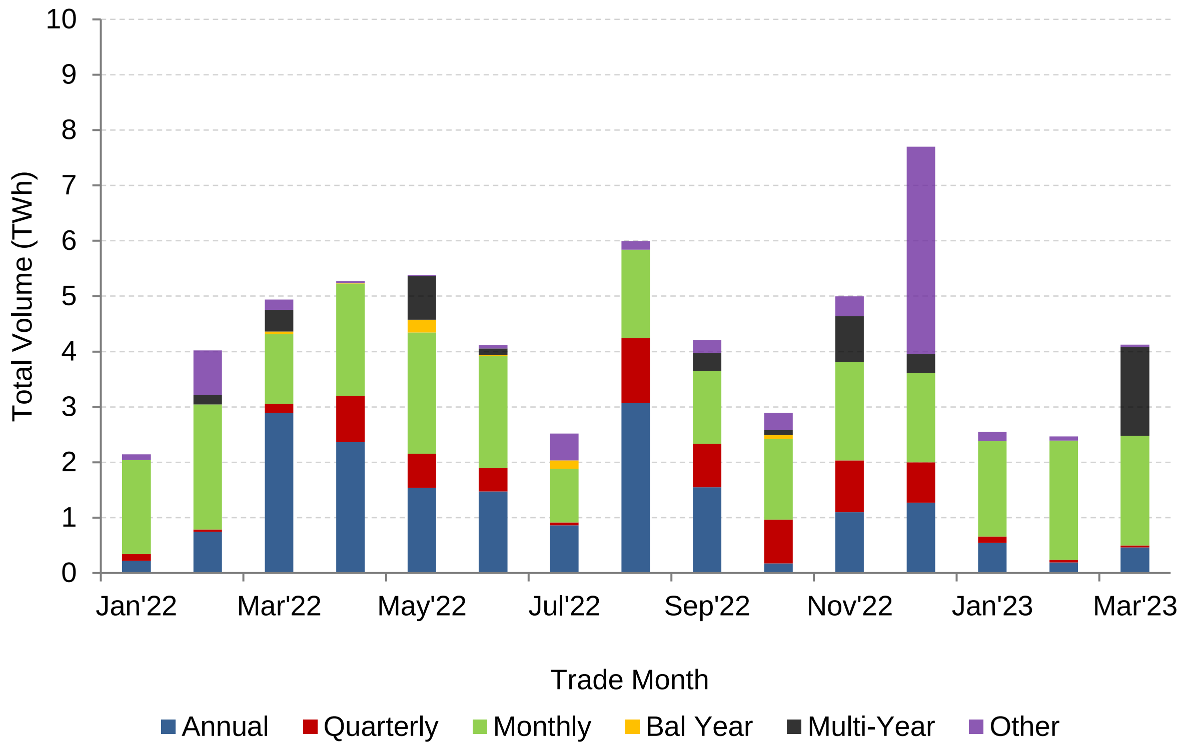
4 THE FORWARD MARKET

4.1 Forward market volumes

The financial forward market is an important component of Alberta's energy-only market design as it allows generators and larger loads to hedge against pool price volatility. Similarly, the forward market enables retailers to reduce price risk by hedging sales to retail customers.[37]

Total volume is the total amount of power traded financially over the duration of a contract, in MWh. The total volume of power traded through ICE NGX or a broker was 9.1 TWh in Q1, which is 6% lower than in Q1 2022, and 5% lower than in Q4 2022 (Figure 66).[38]

Figure 66: Total volume by trade month and term (January 2022 to March 2023)



Compared to January and February, total volumes in March were higher at 4.1 TWh largely because of two multi-year trades that occurred on March 24 and 30. These flat trades covered CAL24 to CAL30 and CAL24 to CAL27, collectively accounting for 1.6 TWh in total volume, and

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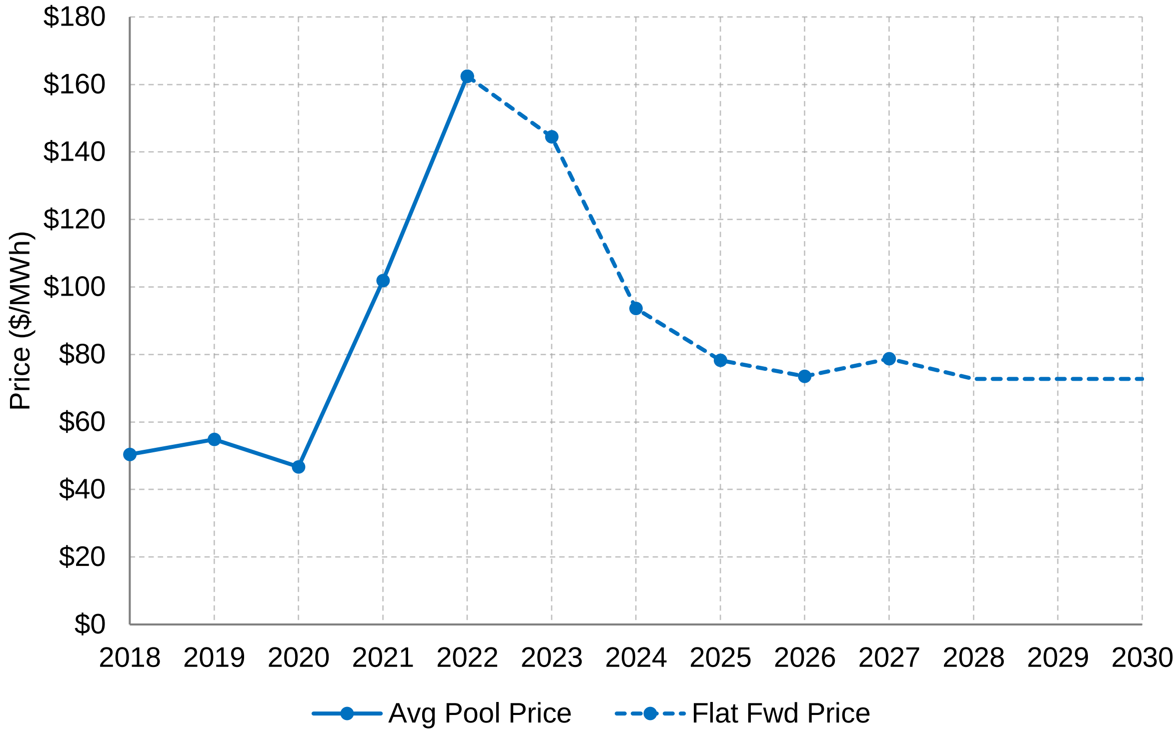
[37] The MSA's analysis in this section incorporates trade data from ICE NGX and two over the counter (OTC) brokers: Canax and Velocity Capital. Data from these trade platforms are routinely collected by the MSA as part of its surveillance and monitoring functions. Data on direct bilateral trades up to a trade date of December 31, 2022 are also included. Direct bilateral trades occur directly between two trading parties, not via ICE NGX or through a broker, and the MSA generally collects information on these transactions once a year.

[38] The figures quoted in the text do not include direct bilateral volumes for the sake of comparison. The total volumes shown in the figure include direct bilateral trades up to December 31, 2022.

were priced at $77.35/MWh and $81.00/MWh, respectively. Combined with prevailing forward prices for earlier years, these trades implied forward prices of $78.61/MWh for CAL27, and $72.87/MWh for CAL28 to CAL30 (illustrated in Figure 67).

Figure 67: The annual forward curve for power (as of late March 2023, nominal $)



4.2 Trading of monthly products

Forward prices for the January and February monthly contracts traded well above where realized pool prices settled. The volume-weighted average forward price for January was $240/MWh, a forward premium of $113/MWh relative to the average pool price of $126/MWh. For February the forward premium was $111/MWh. The forward market premium for these two months contrasted with the forward market discount for most months in 2021 and 2022 (Figure 68).

Mild weather for much of January and February meant high wind generation, reduced demand, lower natural gas prices, and lower power prices in Mid-C and California. In addition, less capacity was offered into the energy market at higher prices in Q1 compared to Q3 2022 and Q4 2022.

Figure 68: Monthly forward prices compared to realized pool prices (January 2021 to March 2023)

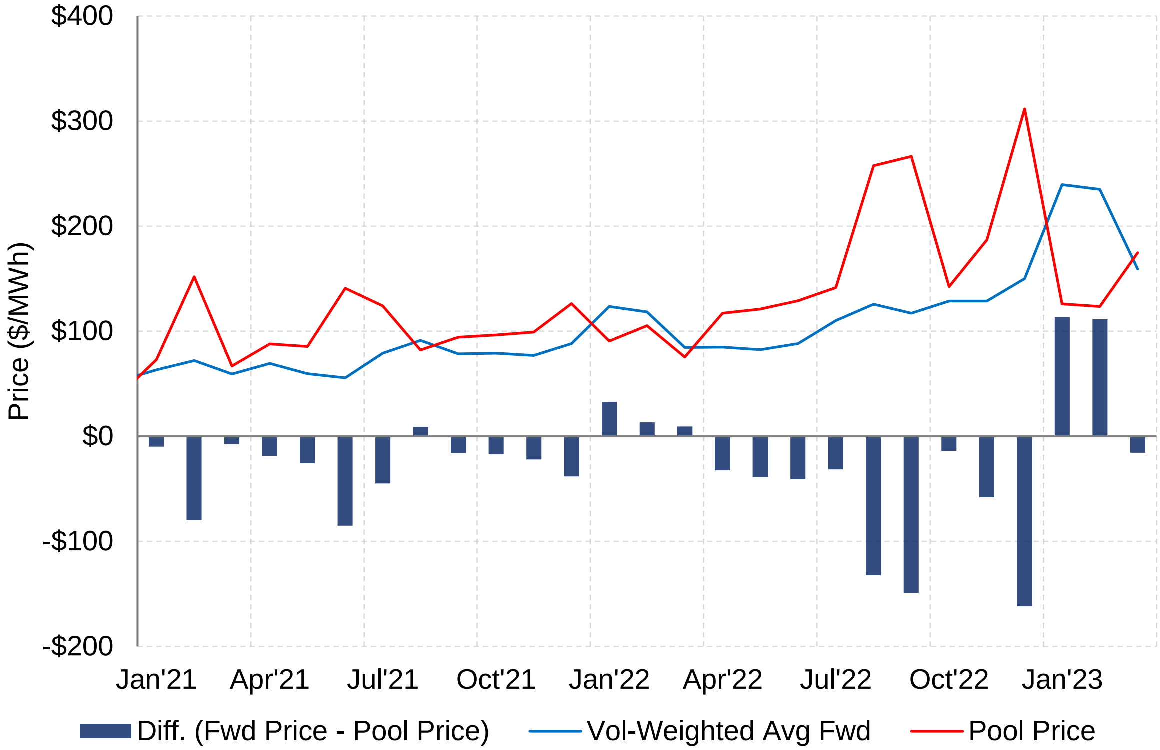


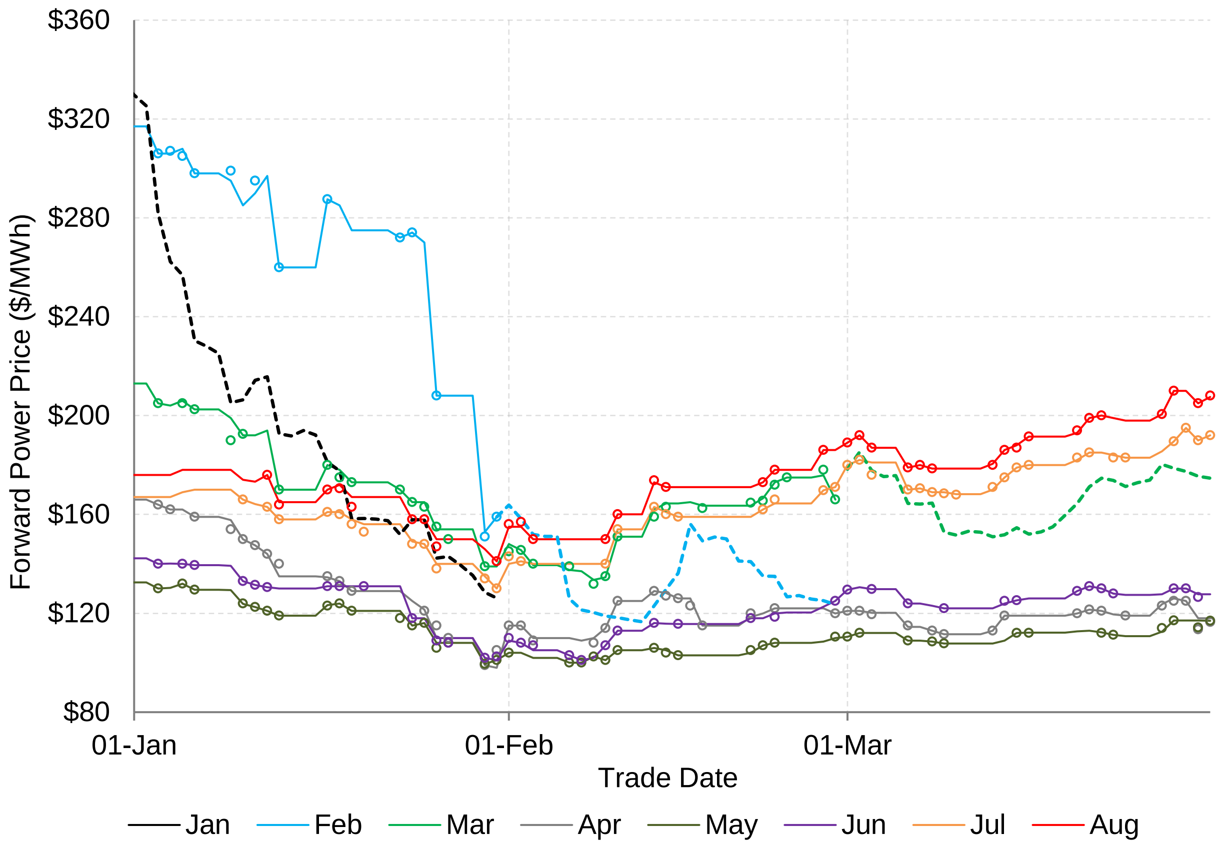
Figure 69 shows the evolution of forward prices for select monthly contracts over the course of trading in Q1. The dashed lines in the figure illustrate the marked prices for January, February, and March. These marked prices use realized pool prices and balance-of-month forward prices to show how the expected average pool price for the month changed over time. The markers in the figure show the final trade price for a given contract on that date.

The marked price for January fell early in the month due to warm weather expectations and lower-than-expected pool prices. The expected price of January fell from $335/MWh on December 30 to $205/MWh on January 9, a decline of 39%. Prices continued to fall further with the month settling at $126/MWh, or 62% below the last trade price on December 30. The lower-than-expected pool prices in January put downward pressure on forward prices.

Over four trading days from January 24 to 30, the forward price for February fell from $274/MWh to $151/MWh, a decline of 45%. This decline was largely due to changes in weather expectations, which went from cold to mild. As outlined above, mild weather conditions can put downward pressure on pool prices for several reasons.

The price of March traded at a premium to other spring months in part because of the scheduled outage at the Shepard combined cycle asset (868 MW). From March 1 to 8 the Shepard asset was fully offline, and the asset was then derated to around 50% capacity until March 23. The 50% derate at Shepard was scheduled well in advance, but the full outage was scheduled later, in mid-December 2022.

Figure 69: The price of select monthly flat contracts over time
(January 1 to March 31, 2023)



The on-going outage at the HR Milner gas asset (300 MW) was extended further in late February. The HR Milner asset went offline to convert from simple cycle to combined cycle in early September 2022 and was initially scheduled to be back online in early November 2022. However, the outage was subsequently extended, as discussed in the MSA's Quarterly Report for Q4 2022. On February 23, the asset's return date was extended further to late August. This put upward pressure on the price of August, which increased from $173/MWh to $178/MWh on February 23.

Despite low natural gas prices, forward power prices for the summer months have been elevated. As of March 31, the July power contract was priced at $192/MWh and the natural gas price for July was $1.75/GJ. Therefore, the July contract was priced at a heat rate of 110 GJ/MWh, while August was valued at a heat rate of 96 GJ/MWh.

The Alberta forward price for August was discounted to, and highly correlated with, the Mid-C August price over Q1 (Table 17). The Mid-C premium over Alberta for August contrasts with the discount seen for earlier delivery months. Hydro supplies in Mid-C for the coming year are forecast to be below normal, and hydro supplies in BC are also expected to be slightly below normal, which is putting upward pressure on power prices in the Pacific Northwest.[39]

Table 17: Forward flat prices in Alberta and Mid-C for April to August (as of March 31, 2023)

	Price as of March 31 ($CAD)			AB – Mid-C correlation coefficient over Q1
	Alberta	**Mid-C**	**Differential (AB – Mid-C)**	
Apr-23	$118	$118	($0)	-0.13
May-23	$117	$85	$32	0.16
Jun-23	$128	$81	$47	0.29
Jul-23	$192	$166	$26	0.65
Aug-23	$208	$259	($51)	0.90

On Friday, March 10 the AESO released the Reliability Roadmap and announced that the LSSi requirements for imports would increase for reliability reasons. The main impact of higher LSSi requirements is to reduce import capacity and lower import supply. As a result, forward prices increased on the back of this announcement. For example, the price of April increased by 7%, from $112/MWh on March 10 to $119/MWh on March 16 (Table 18).

Table 18: Monthly forward prices for April to December (as of March 10 and 16)

	March 10	**March 16**	**% Chg.**
Apr-23	$112	$119	7%
May-23	$108	$112	4%
Jun-23	$122	$126	3%
Jul-23	$168	$180	7%
Aug-23	$179	$192	7%
Sep-23	$141	$148	5%
Oct-23	$112	$121	8%
Nov-23	$109	$117	7%
Dec-23	$140	$147	5%

4.3 RRO full load premium

Alberta has a competitive retail electricity sector wherein retail customers can choose to buy their electricity from a number of different sources and for different lengths of time. Retail customers that consume less than 250,000 kWh annually are eligible for the RRO, a regulated electric energy

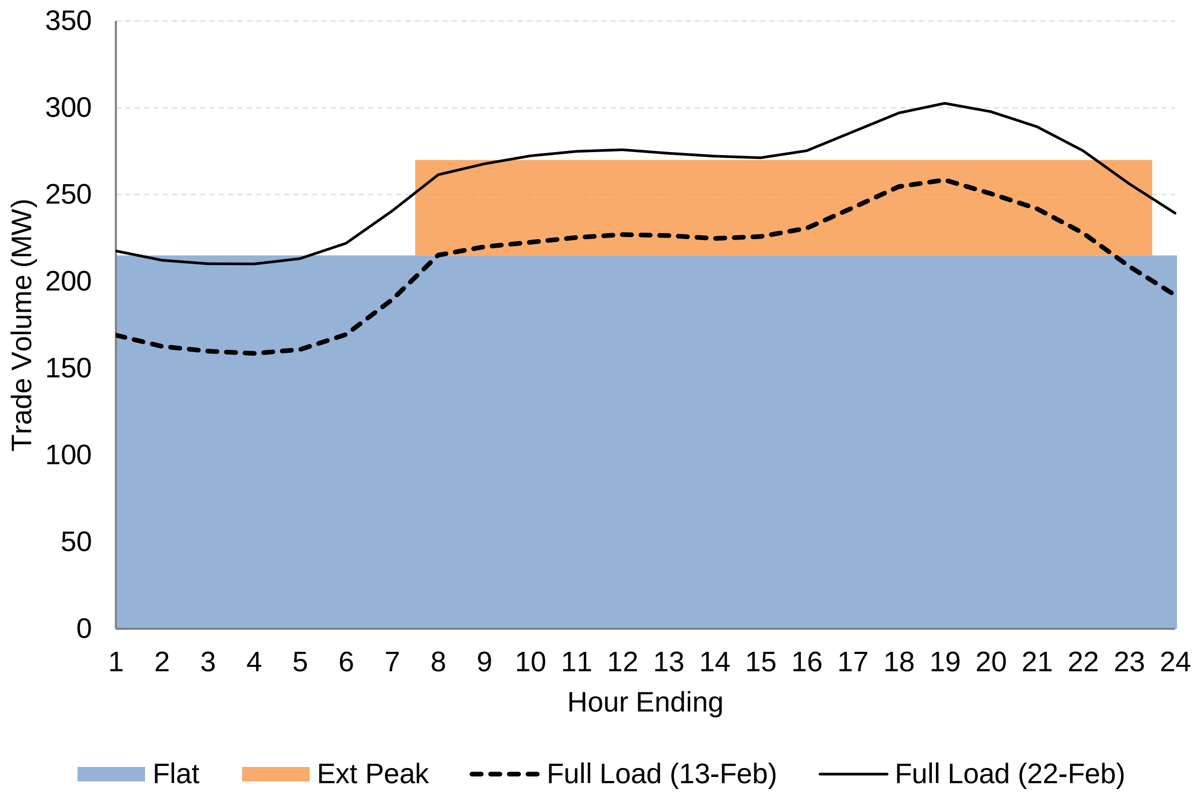
[39] Northwest River Forecast Centre, Water Supply Forecasts, see Dalles Dam and Mica Dam for example

BC Government, Snow Survey and Water Supply Bulletin, April 1, 2023 rate for customers that do not sign a contract with a competitive electricity retailer. As of December 31, 2022, approximately 36% of residential customers procured their electricity through an RRO provider. Retail customers that are on the RRO can choose to leave the RRO at any time, and instead sign a contract with a competitive electricity retailer.

The RRO rate in any given month is linked to forward prices in the months leading up to that RRO rate period. This is because RRO providers procure different types of monthly products in the forward market to meet their forecasted load. For more discussion on how the RRO procurements are undertaken see the MSA's Quarterly Report for Q1 2021.[40]

The two largest RRO providers, EPCOR and ENMAX, serve approximately 85% of total RRO consumption. The RRO rates set by EPCOR and ENMAX are largely determined by the price of purchasing full load strips in forward market auctions.[41]

Figure 70: Flat, extended peak, and full load shapes
(An example from EPCOR's February 2023 procurement)[42]



[40] MSA Q4 2021 Quarterly Report at page 43

[41] For the January, February, and March 2023 delivery months, a 13.5 c/kWh rate ceiling was applied to the RRO rates in accordance with the *Regulated Rate Option Stability Act*. The resulting deferral amounts are scheduled to be paid back over the April 2023 to December 2024 delivery months.

[42] The full load volumes represent 50% of EPCOR's realized consumption based on interim settlement figures.

Full load strips differ from other forward market products, such as flat and extended peak (Figure 70). While the flat and extended peak products specify a fixed quantity of electricity, full load strips instead specify a certain percentage of the actual RRO hourly load. For instance, a seller may commit to financially provide 1% of EPCOR's RRO load in August at a fixed price, so the volume traded will fluctuate from hour to hour as EPCOR's RRO load changes with the weather, time of day, and day of the week, etc. On average, the full load strips are each expected to result in a 4 MW volume, but the final settlement amount is not completely known until about four months after the delivery month.

The full load product is unique to the RRO auctions and acts as a means of valuing the price and quantity risks associated with supplying regulated retail electricity products. Historically, a combination of flat and extended peak forward products were procured to cover the regulated retailer's load profile. As a result, for hours where demand was higher than the procured volume, the retailer would have to buy power at pool price, and in hours where demand was lower than the procured volume, the retailer would be selling power at pool price. Prior to the adoption of the full load procurement mechanism, RRO providers were compensated for these price and quantity risks based on the historical commodity gains and losses in accordance with the RRO provider's Energy Price Setting Plan (EPSP) that was approved by the Alberta Utilities Commission.

The full load procurement mechanism was first proposed as part of the EPCOR 2018-2021 EPSP, with April 2019 being the first delivery month. A similar mechanism was introduced for the December 2020 delivery month under the ENMAX 2019-2022 EPSP. Under the new procurement mechanism, RRO rates are largely determined by the price of full load strips purchased in the auctions.

The analysis that follows focuses on the EPCOR RRO due to the longer period of available full load data, and because EPCOR is the largest RRO provider.

Figure 71 compares the price of full load strips from EPCOR RRO procurement auctions (the blue line) with the weighted-average pool price, where pool prices are weighted by realized EPCOR RRO hourly consumption (the red line; this is what the full load settles against). Since April 2019 the full load product has traded at a slight discount of 0.6% (on average) to the weighted-average pool price and has incurred less volatility.

However, for Q1 2023 the forward price of the full load products traded at a forward premium of 76% relative to the weighted-average pool price. As discussed in section 4.2, monthly forward prices generally traded at a premium to pool prices in Q1 2023.

Table 19 shows how the auction prices compared with the weighted-average pool prices for two separate periods: first, April 2019 to December 2020 and second, January 2021 to March 2023. In the first period, the full load products in the auction traded at a premium of 26% relative to the weighted-average pool price. In the second period, the full load products in the auction traded at a discount of 9%.

Similar general trends were observed for forward flat prices. From April 2019 to December 2020, the flat prices in the auctions traded at a premium of 16% relative to the average pool price (Table 19). From January 2021 to March 2023 flat prices in the auctions traded at a 16% discount relative to the average pool price.

Figure 71: Monthly EPCOR RRO auction full load prices and weighted-average pool prices (April 2019 to March 2023)

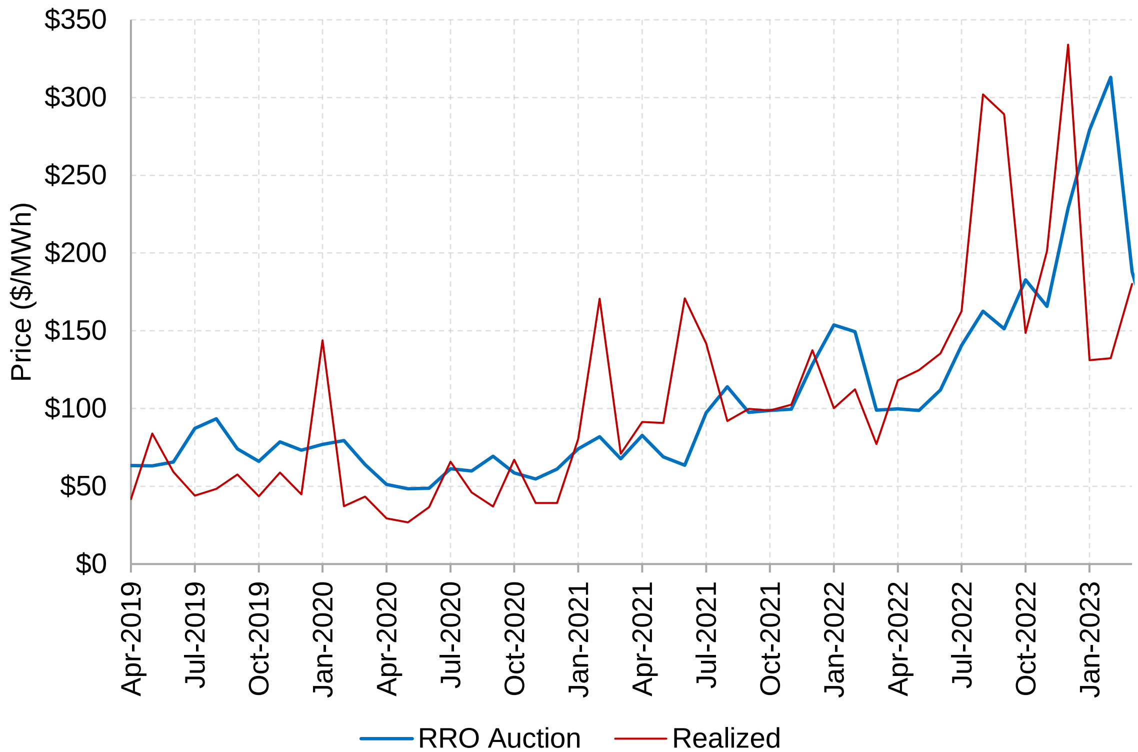


Table 19: EPCOR RRO auction and realized pool prices

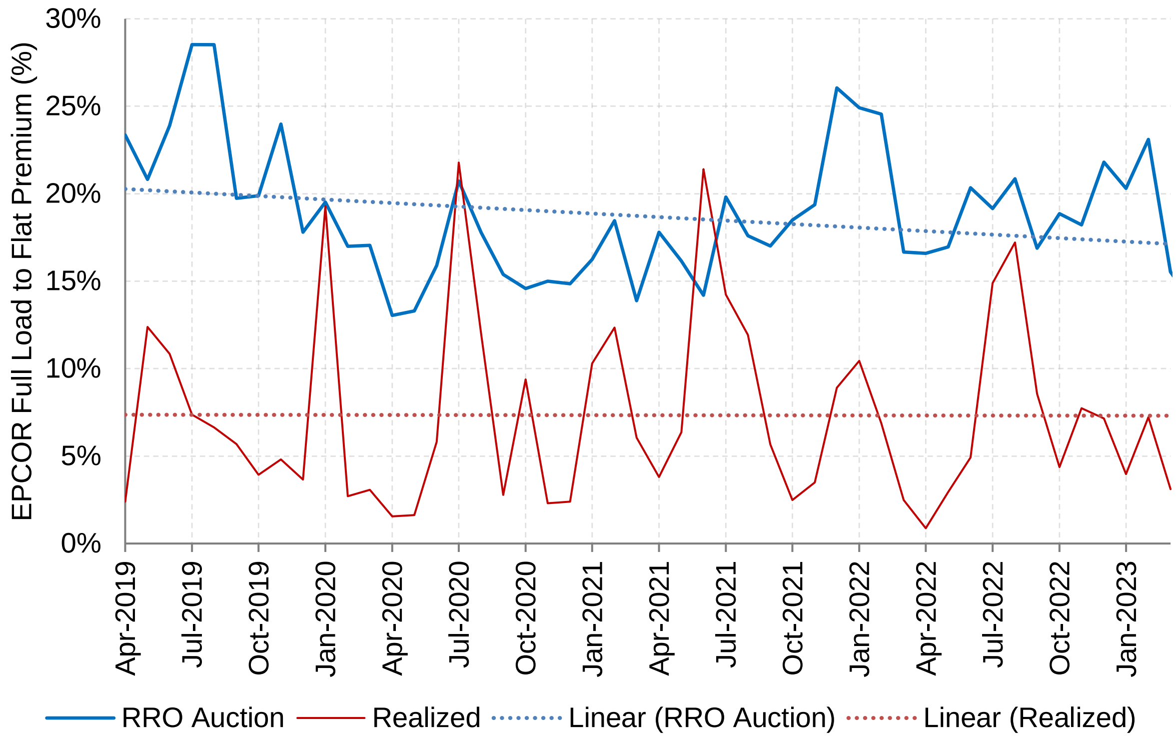
		RRO auction (forward)	**Pool Price (realized)**	**Forward auction premium (%)**
Apr 2019 to Dec 2020	Flat	$55.74	$48.17	16%
	Full load	$66.93	$53.20	26%
	Full load to flat premium (%)	20%	10%	10%
Jan 2021 to Mar 2023	Flat	$111.35	$133.27	-16%
	Full load	$130.83	$143.50	-9%
	Full load to flat premium (%)	17%	8%	10%

The full load to flat premium is the ratio of the full load price to the flat price. In the forward RRO auctions, this metric provides an indication of the expected price and quantity risks for a given month (the RRO column in Table 19). On a realized basis, the full load to flat premium is calculated as the ratio of the weighted pool price to the average pool price (the pool price column).

Prior to 2021, the EPCOR RRO auctions priced the full load to flat premium at 20% on average. On a realized basis, the full load to flat premium over this period was lower at 10%. Since 2021, the full load to flat premium in the EPCOR RRO auctions has averaged 17%, but the realized full load to flat premium was lower at 8%. These figures indicate that the full load product has been overpriced in the RRO auctions relative to the price of the flat product.

The blue line in Figure 72 shows the full load to flat premium in the EPCOR RRO auctions by delivery month. The red line in the figure shows the realized full load to flat premium based on actual pool prices and EPCOR consumption. The RRO full load to flat premium has frequently been higher than the realized full load to flat premium, and the magnitude is variable from month to month. Only in a small number of volatile months did the realized full load to flat premium come close to, or slightly exceed, the full load to flat premium traded in the RRO auctions.

Figure 72: Monthly EPCOR RRO full load to flat premium versus the realized full load to flat premium (April 2019 to March 2023)



4.4 Trading of annual products

The expected average pool price for 2023 fell by 32% from $181/MWh to $122/MWh over January as pool prices in January came in below forward expectations, the forward price of February declined, and forward prices for the rest of 2023 responded to lower-than-expected pool prices and falling natural gas futures. The marked price of CAL23 recovered somewhat over February and March but was still down 20% over the quarter (Figure 73).

Forward prices for future years were comparatively stable but prices did increase in late 2022 and fall in early 2023, following the same general trends as CAL23 (Figure 73). The price of CAL25 fell by 12% over Q1 despite an increase in the price of natural gas for that year. Consequently, the spark spread for CAL25 fell by 25% over the quarter (Table 20).

Figure 73: Annual flat forward prices over time (October 1, 2022 to March 31, 2023)

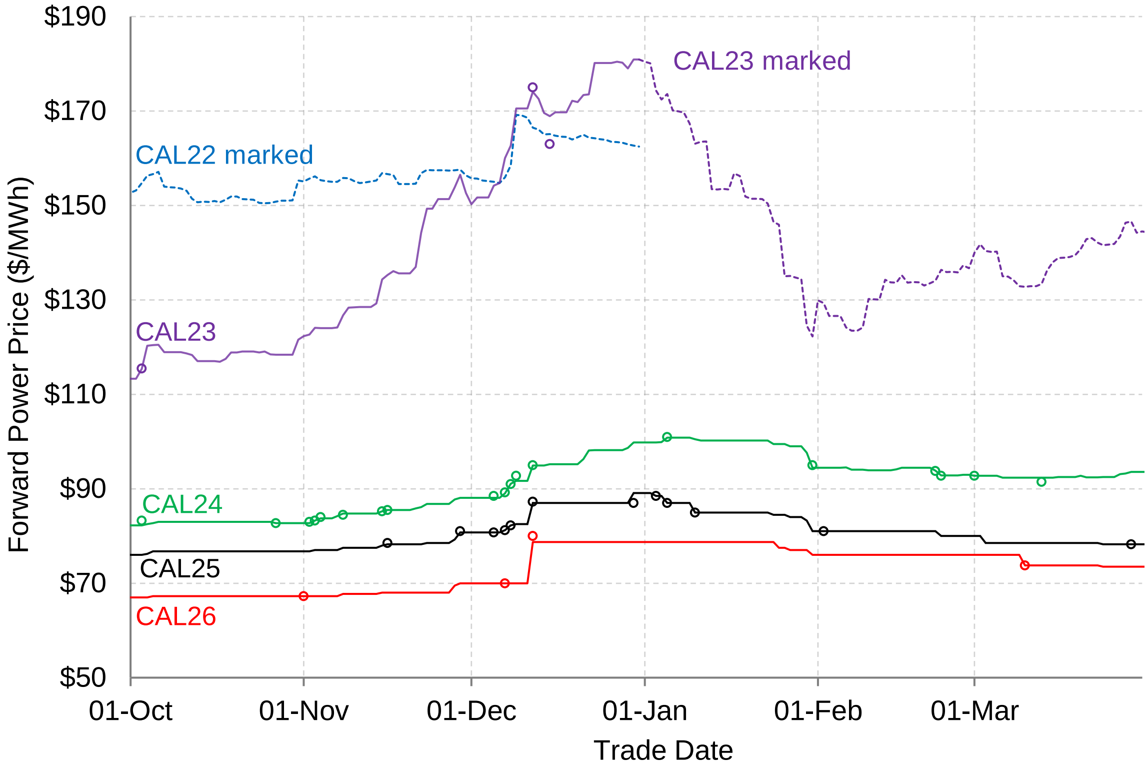


Table 20: Forward power and natural gas price changes over Q1

Contract	Power price ($/MWh)			Gas price ($/GJ)			Spark spread ($/MWh)		
	Mar 31	Dec 31	% chg	Mar 31	Dec 31	% chg	Mar 31	Dec 31	% chg
CAL23 (Marked)	$145	$181	-20%	$2.66	$3.59	-26%	$118	$145	-19%
CAL24	$94	$100	-6%	$3.42	$3.68	-7%	$59	$63	-6%
CAL25	$78	$89	-12%	$4.17	$4.02	4%	$37	$49	-25%
CAL26	$74	$79	-7%	$4.25	$4.37	-3%	$31	$35	-11%

5 THE RETAIL MARKET

5.1 Quarterly summary

Residential retail customers can choose from several retail energy rates. By default, retail customers are on regulated energy rates, which vary monthly and by distribution service area.

Alternatively, customers may sign with a competitive retailer. Competitive retailers typically offer both fixed and variable energy rates. Fixed energy rates are typically set for a period between one and five years, while competitive variable energy rates vary monthly.

In December 2022, the Alberta legislature enacted the *Regulated Rate Option Stability Act* (RROSA). The RROSA placed a ceiling on regulated electricity rates at a maximum of 13.5 cents/kWh for the months of January, February, and March 2023. As a result of this ceiling, the average of RRO rates in Q1 2023 was 6% lower compared to Q1 2022 (Table 21).

Average residential competitive variable electricity rates were 50% higher in Q1 compared to the previous year, but fell 32% compared to Q4 2022, driven largely by changes in pool prices.

Table 21: Monthly retail market summary for Q1 (Residential customers)

		2023	2022	Change
RRO (Avg ¢/kWh)	Jan	13.50	16.20	*-17%*
	Feb	13.50	16.18	*-17%*
	Mar	13.50	10.72	*+26%*
	Q1	**13.50**	**14.31**	***-6%***
DRT (Avg $/GJ)	Jan	6.43	3.65	*+76%*
	Feb	3.45	5.05	*-32%*
	Mar	2.54	4.94	*-49%*
	Q1	**4.16**	**4.53**	***-8%***
Competitive variable electricity rate (Avg. ¢/kWh)	Jan	14.23	10.67	*+33%*
	Feb	13.94	12.20	*+14%*
	Mar	18.77	8.67	*+116%*
	Q1	**15.70**	**10.46**	*+**50%***
Competitive Variable Natural Gas rate (Avg. $/GJ)	Jan	4.58	5.18	*-12%*
	Feb	3.64	5.48	*-34%*
	Mar	3.98	5.83	*-32%*
	Q1	**4.08**	**5.50**	***-26%***
Expected cost, 3-year electricity contract (Avg. ¢/kWh)	Jan	11.98	7.61	*+57%*
	Feb	10.54	7.46	*+41%*
	Mar	10.37	7.66	*+35%*
	Q1	**10.98**	**7.58**	***+45%***
Expected cost, 3-year natural gas contract (Avg. $/GJ)	Jan	3.80	3.37	*+13%*
	Feb	3.36	3.64	*-8%*
	Mar	3.86	3.94	*-2%*
	Q1	**3.68**	**3.65**	***1%***

The average residential Default Rate Tariff (DRT) rates decreased from $5.59/GJ in Q4 2022 to $4.16/GJ in Q1. DRT rates were $0.37/GJ lower year-over-year in Q1. Competitive variable natural gas rates were also lower year-over-year in Q1 2023 and were below prevailing DRT rates due to the drop in natural gas prices over February and March this year.

The expected cost of providing 3-year fixed rate electricity contracts was 45% higher year-over-year in Q1, but 8% less than in Q4 2022. On the other hand, the expected cost of providing 3-year fixed rate natural gas contracts remained largely unchanged year-over-year in Q1, but fell 20% compared to Q4 2022.

5.2 Retail customer movements

The MSA collects and tracks retail switching data on a one-quarter lagged basis. As such, the discussion in this section focusses on retail switching in and prior to Q4 2022.

5.2.1 Regulated retailer customer losses

The total number of residential RRO customers fell by around 20,000 in Q4 2022, a net loss of 3% compared to Q3 2022. The total number of residential DRT customers fell by around 14,000 in Q4 2022, a net loss of over 3% customers.

The net loss in RRO customers in Q4 2022 was around 1,000 more than what was observed in Q3 2022 (Figure 74). Around 44,000 residential customers left the RRO in Q4, while the RRO gained 24,000 new residential customers (Figure 75).

Figure 74: RRO customer net losses, residential customers (Q1 2020 to Q4 2022)

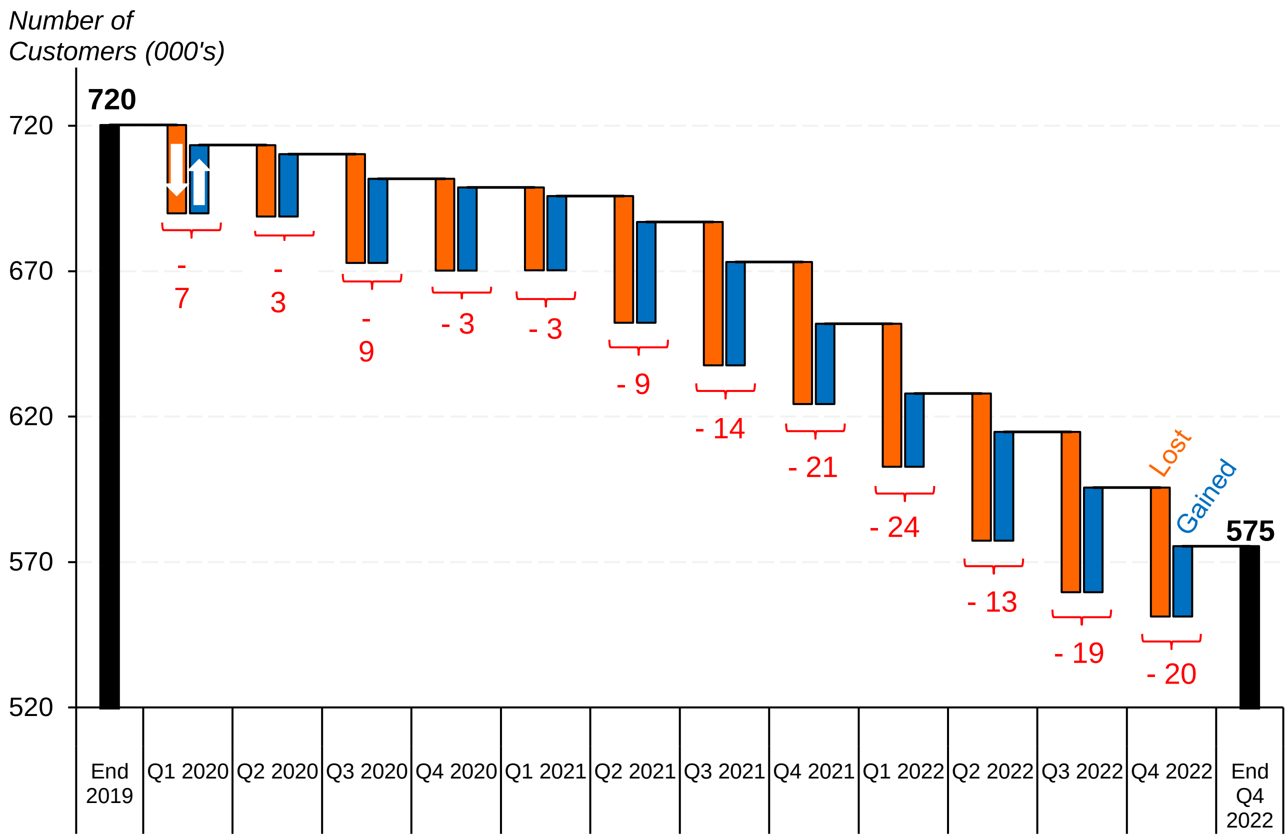
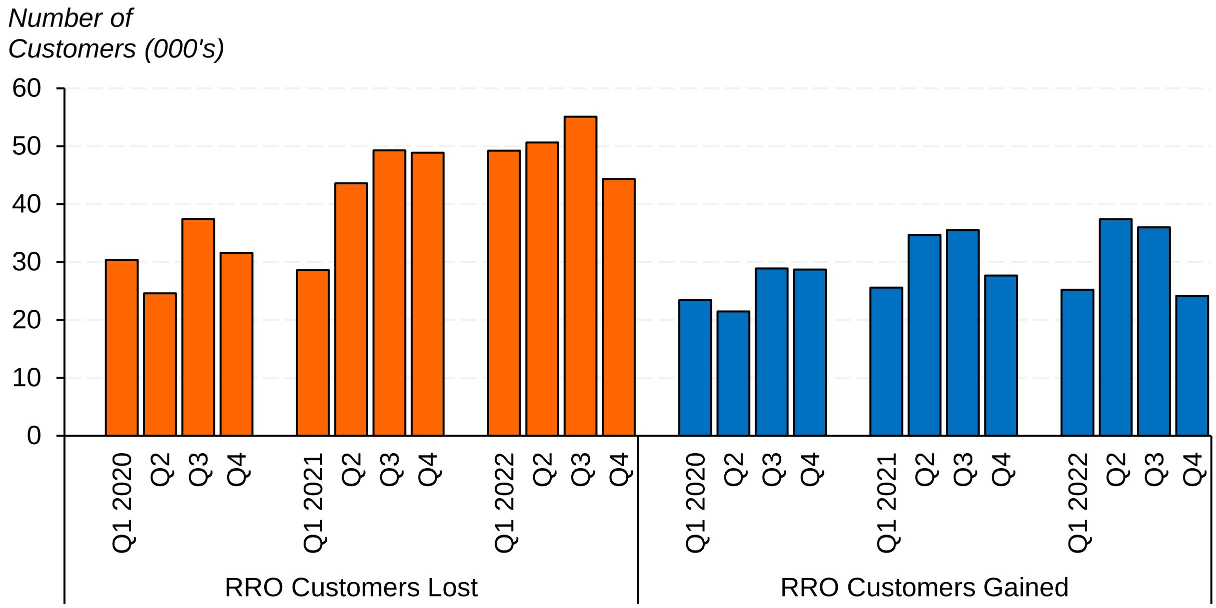


Figure 75: RRO customer losses & gains, residential customers (Q1 2020 to Q3 2022)



The DRT also continued to lose customers in Q4 2022, losing around 14,000 residential customers (on net), 3,000 more than in the previous quarter (Figure 76). The magnitude of DRT customer losses and gains in Q4 were relatively low compared to Q2 and Q3 (Figure 77). Around 28,000 residential customers left the DRT in Q4, while the DRT gained around 14,000 new residential customers.

Figure 76: DRT customer net losses, residential customers (Q1 2020 to Q4 2022)

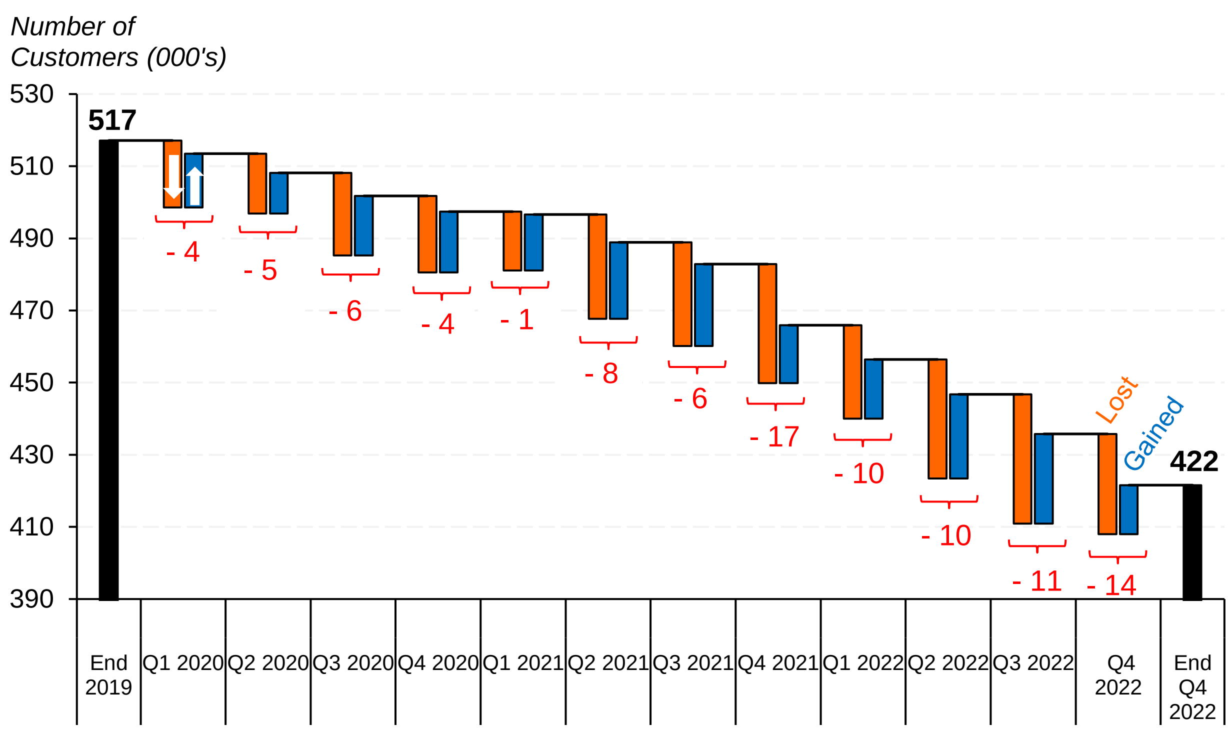
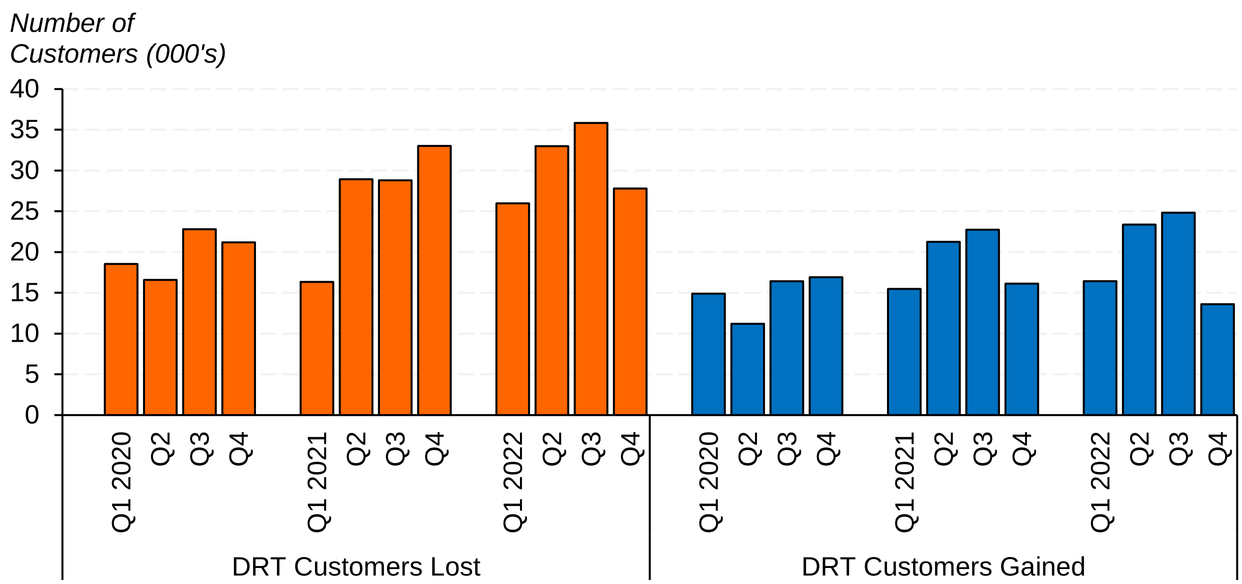


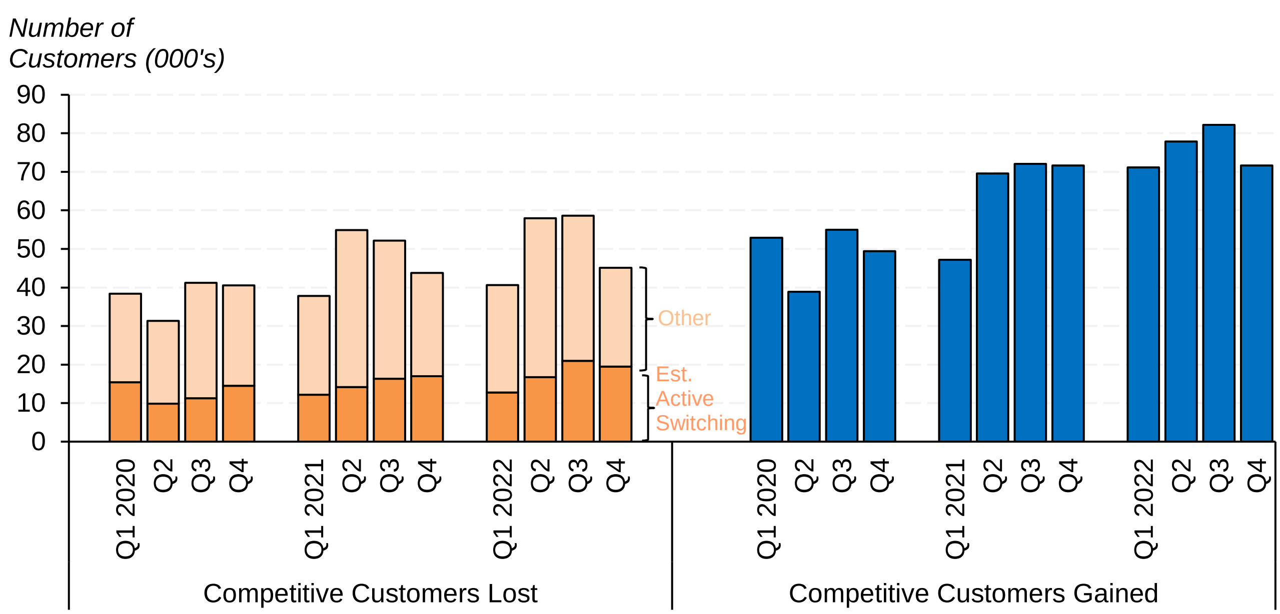
Figure 77: DRT customer losses & gains, residential customers (Q1 2020 to Q4 2022)



5.2.2 ***Competitive retailer customer gains***

Competitive electricity retailers gained around 72,000 new residential customers in Q4 2022, 10,000 less than in the previous quarter (Figure 78). However competitive residential customer losses in Q4 dropped by around 25%, compared to Q3. Out of the 45,000 customers that left their competitive retailer, roughly 26,000 of these losses were driven by residential customers dropped or moved during the quarter. Such customers are counted as a loss of a customer despite the possibility they might return to their competitive retailer.

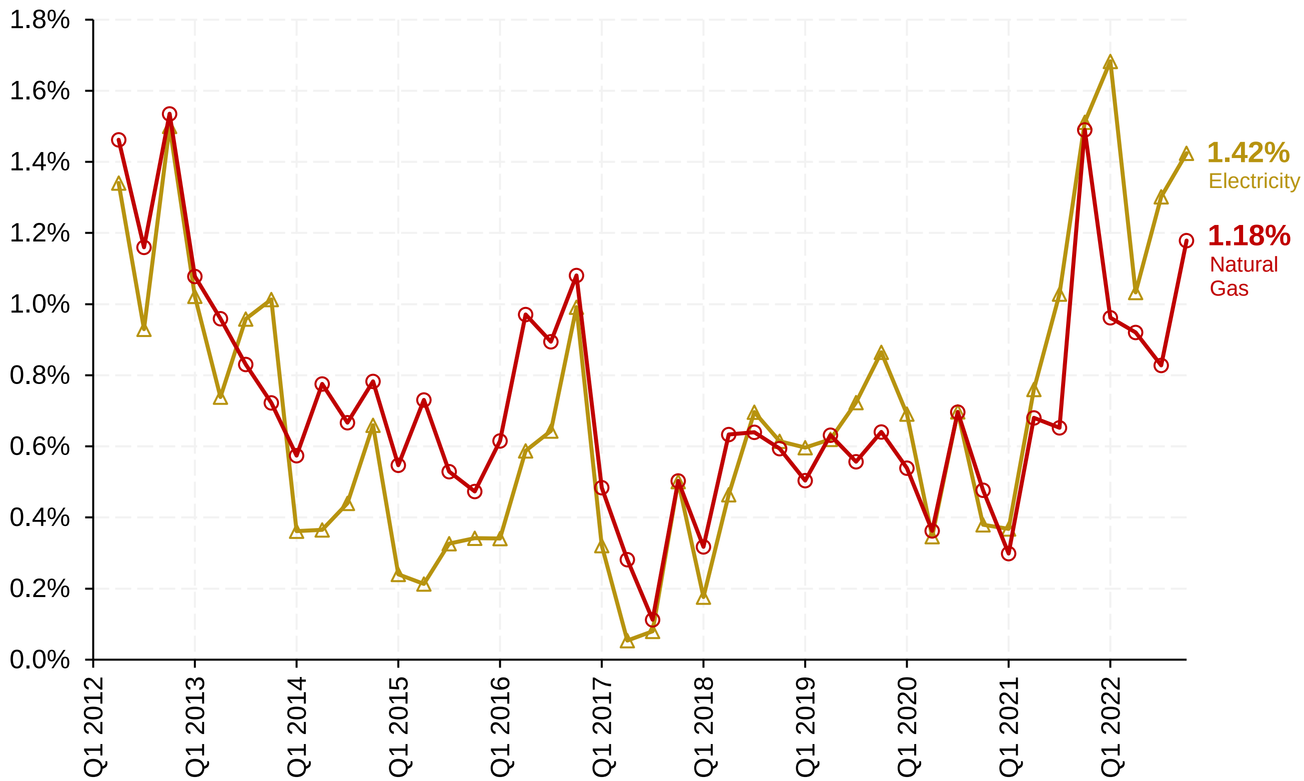
Figure 78: Competitive electricity customer losses & gains, residential customers (Q1 2020 to Q4 2022)



The MSA estimates around 19,000 residential customers left their competitive retailer for reasons unrelated to a move or because of being dropped by their retailer in Q4. The MSA counts such a switch as an 'Active Switch' because the decision to leave for these customers may have been motivated by economic factors such as more advantageous competing rate offerings.

Competitive retail customer shares among residential customers for electricity and natural gas increased by 1.42% and 1.18% respectively in Q4 2022 (Figure 79). These rates are higher compared to the rate of increases observed in the in Q2 and Q3 2022.

Figure 79: Quarterly increase in competitive retail customer share, residential customers (January 2012 to December 2022)



The largest increase in competitive market share among residential electricity customers in Q4 was observed in EPCOR service areas. Among residential natural gas customers, the increase in market share was highest in the Apex service area (Table 22). Overall, 64% of residential electricity customers and 68% of residential natural gas customers were served by a competitive retailer as of December 31, 2022 (Figure 80 and Figure 81).

Table 22: Competitive shares by service area (residential customers)

	ENMAX	EPCOR	FortisAlberta	ATCO
Change (Q3)	+1.2%	+1.6%	+1.5%	+0.1%
Change (Q4)	+1.1%	+1.8%	+1.5%	+1.3%
Competitive Share (Dec 2022)	77.5%	52.3%	59.0%	61.7%

	ATCO Gas North	ATCO Gas South	Apex
Change (Q3)	+0.8%	+0.7%	+1.8%
Change (Q4)	+1.3%	+1.1%	+1.2%
Competitive Share (Dec 2022)	63.1%	74.3%	38.5%

Figure 80: Competitive retail customer share (Electricity) by service area, residential customers (January 2012 to December 2022)

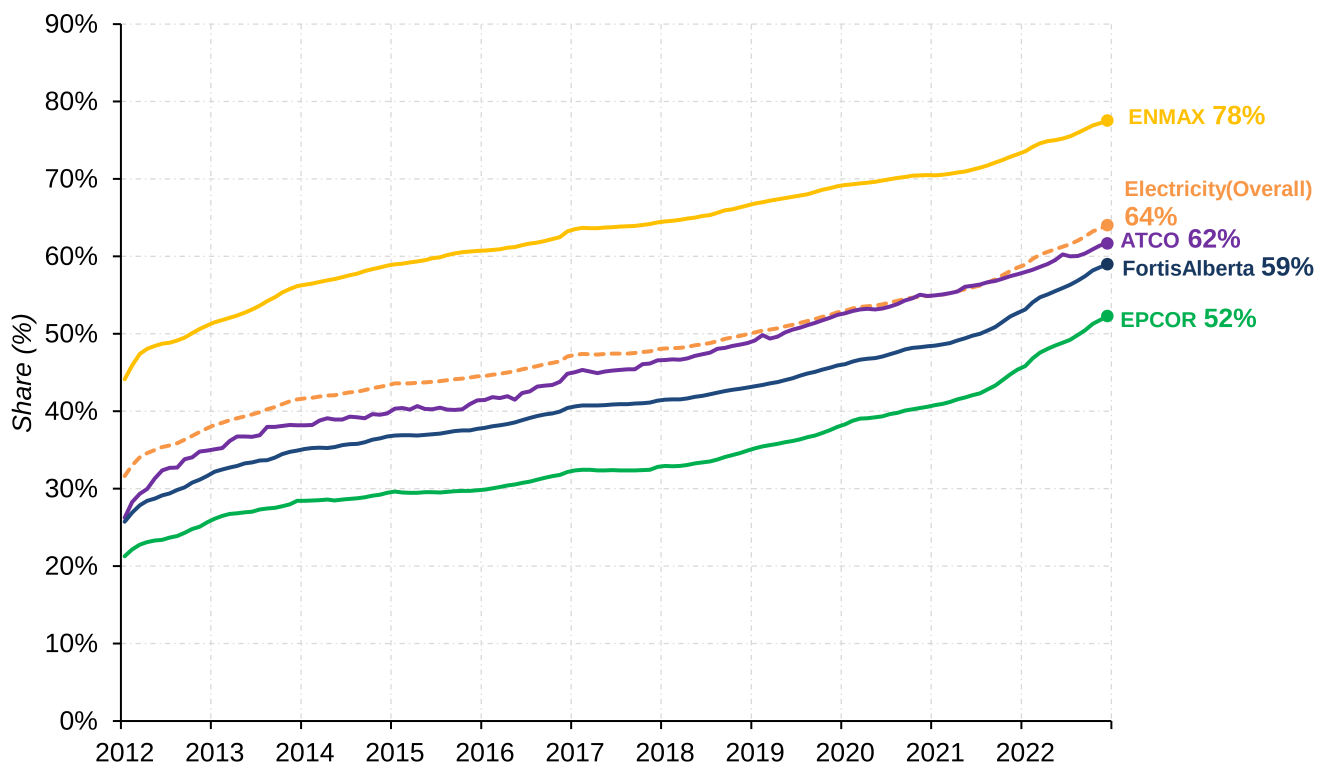
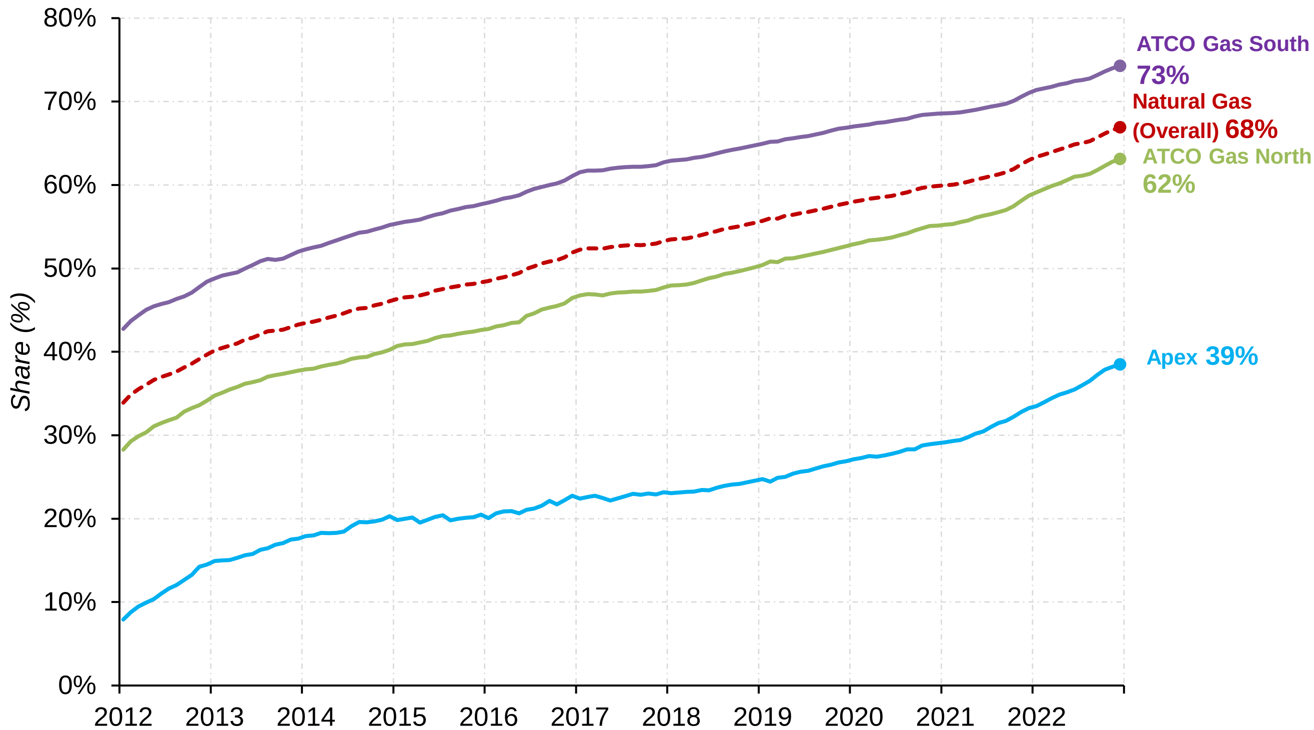


Figure 81:Competitive retail customer share (Natural Gas) by service area, residential customers (January 2012 to December 2022)



5.3 Competitive retail rates

Competitive retail customers typically have access to fixed and variable energy rates. Fixed rates are energy rates that are fixed over a defined contract term, usually one, three or five years. Variable rates are energy rates that vary each month and can be tied to monthly pool prices or regulated rates.

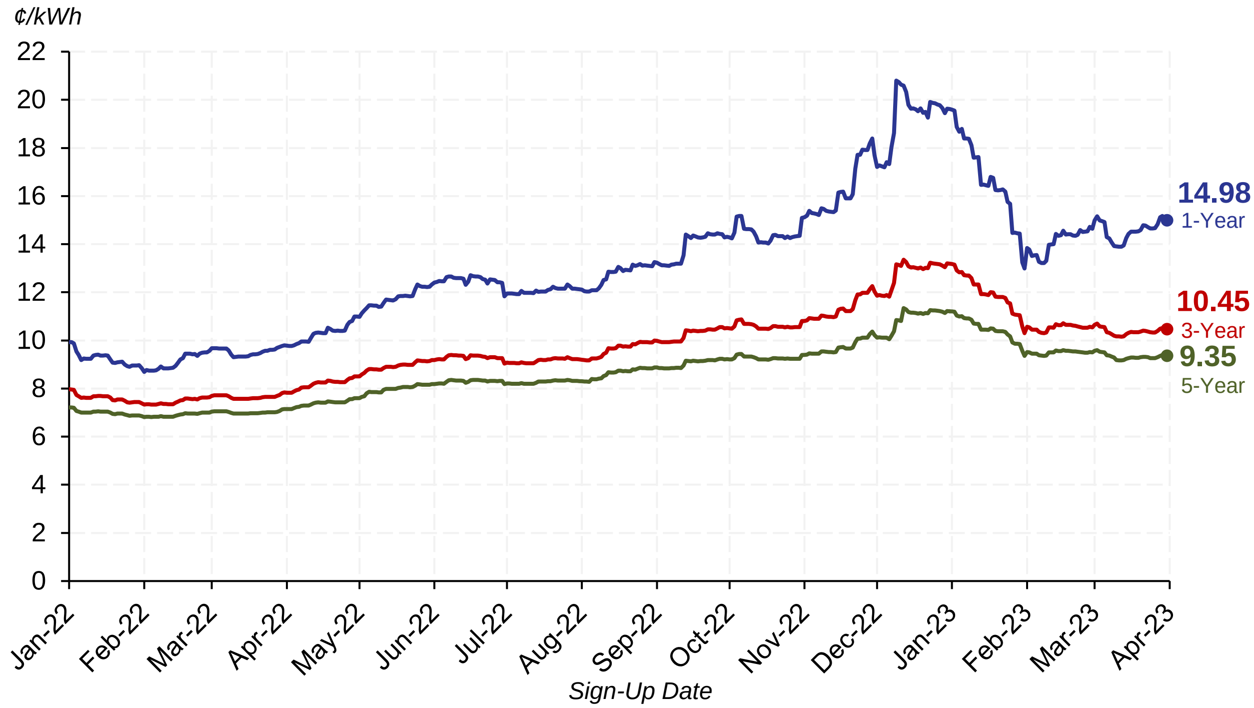
5.3.1 Fixed rate contracts

Retailers offering fixed rates to customers face energy costs associated with that customer's consumption over the length of the contract term. In the long-run, competitive fixed rate prices would be expected to respond to changes in the expected cost of fixed rate contracts as retailers compete away any (expected) positive margins or alter their fixed rates to avoid negative margins.

Expected costs for fixed rate electricity contracts fell substantially in January 2023, driven largely by the drop in near-term forward electricity contract prices. Expected costs for 1-year, 3-year and 5-year contracts decreased by 34%, 22% and 17% respectively in January. Though expected costs for 1-year contracts further increased in February and March, they remained low relative to expected costs as of Q4 2022 (Figure 82)

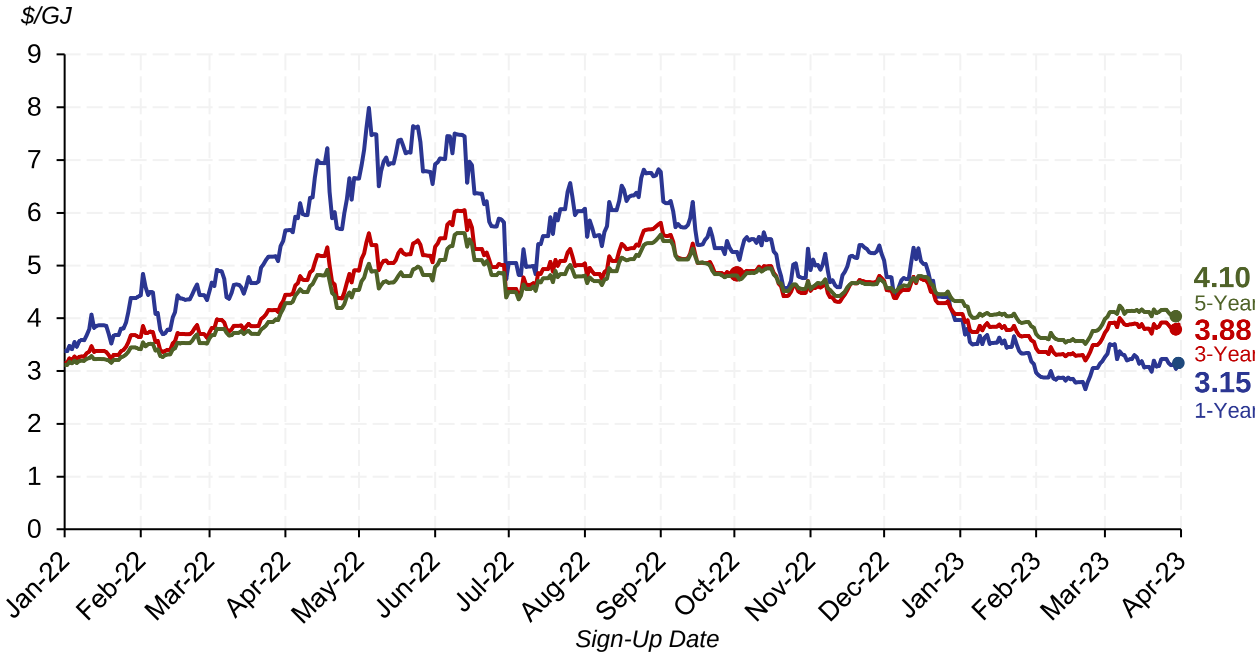
The expected cost of 1-year fixed rate electricity contracts dropped from 19.62 ¢/kWh on December 31 to 14.98 ¢/kWh on March 31, a 24% decline over the quarter. Similarly, the expected costs of longer-term retail electricity contracts also declined in Q1 (Figure 82). The difference in expected cost changes between different length contracts was a result of the much greater appreciation of near-term forward prices compared to longer term forward prices.

Figure 82: Expected cost, fixed rate electricity contract, residential customer (January 1, 2022 to March 31, 2023)



The expected cost for fixed rate natural gas contracts exhibited a different trend in Q1. The expected cost of providing 1-year contracts fell to below the expected cost of 3-and-5-year contracts as a result of significant declines in near-term natural gas prices (Figure 83). The expected cost of a 1-year natural gas contract dropped by $0.82/GJ over the quarter, while the expected costs of 3-year and 5-year natural gas contracts dropped by $0.20/GJ and $0.23/GJ respectively in Q1 2023. Expected costs for 3-year and 5-year contracts were relatively stable in Q1 2023 compared to 2022.

Figure 83: Expected cost, fixed rate natural gas contract, residential customer (January 1, 2022 to March 31, 2023)



Despite the decline in expected costs, competitive fixed rates for electricity generally increased over Q1 2023 (Figure 84). All major retailers (except Retailer B and Retailer E) increased each of their 1, 3, and 5-year fixed rate electricity prices at least once over the quarter. Retailers B and E had rates generally priced above their competitors, and they may have reduced these rates to remain competitive in the retail market.

Fixed rate electricity contract prices had increased notably in the past one year, in a way that some of the short-term fixed rates are comparable to or even higher than the prevailing RRO rates. For example, in January 2022, the 1-year fixed rate electricity rate of Retailer A was 7.99 ¢/kWh, which is 12.10 ¢ less than their current rate of 20.09 ¢/kWh, a 151% rise in rate. Some retailers increased their fixed rate prices to offset the increase in expected costs in February and March.

Figure 84: 1, 3, 5-year fixed rate electricity contract prices, residential customers, ENMAX service area (May 1, 2022 to March 31, 2023)

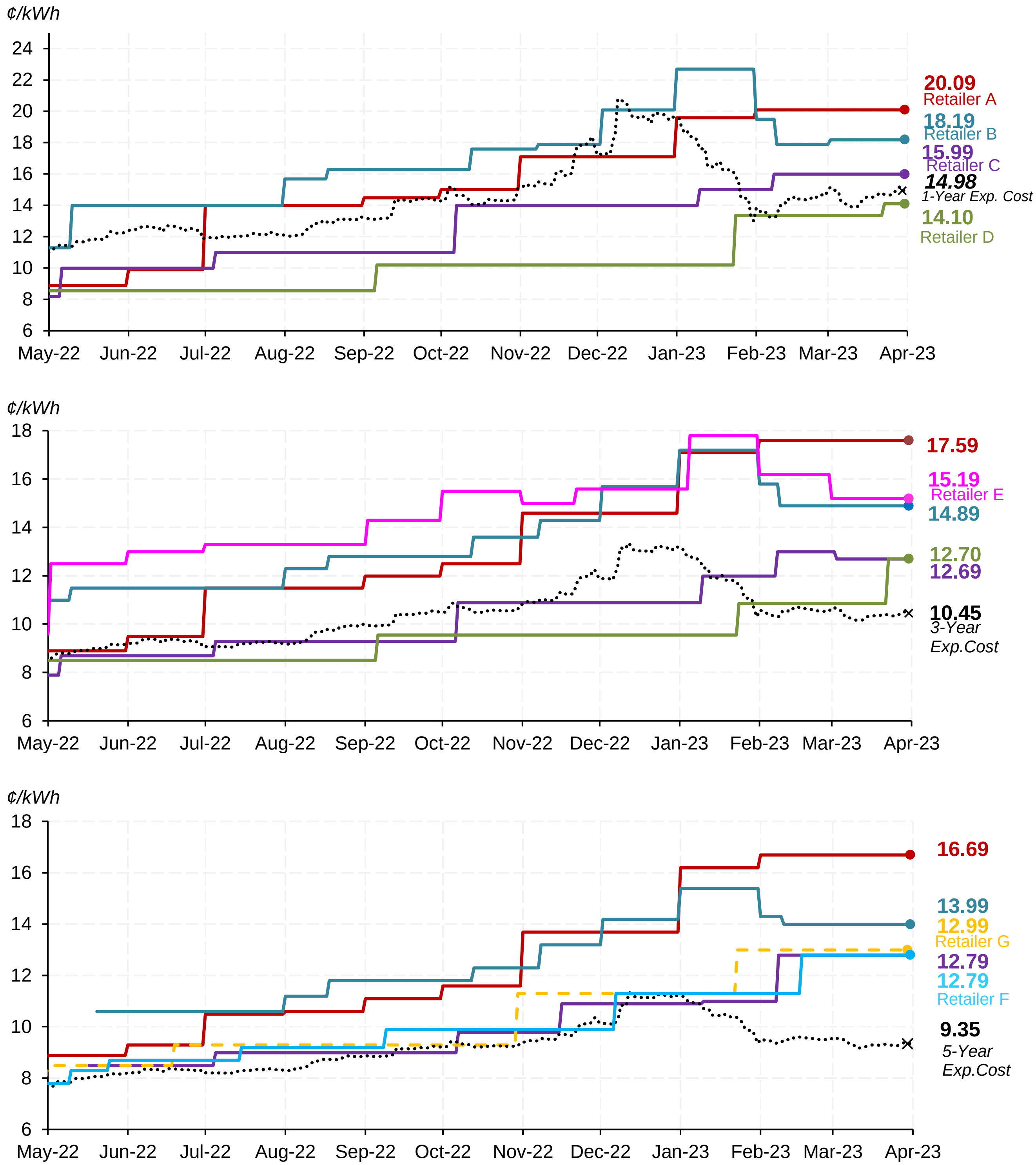
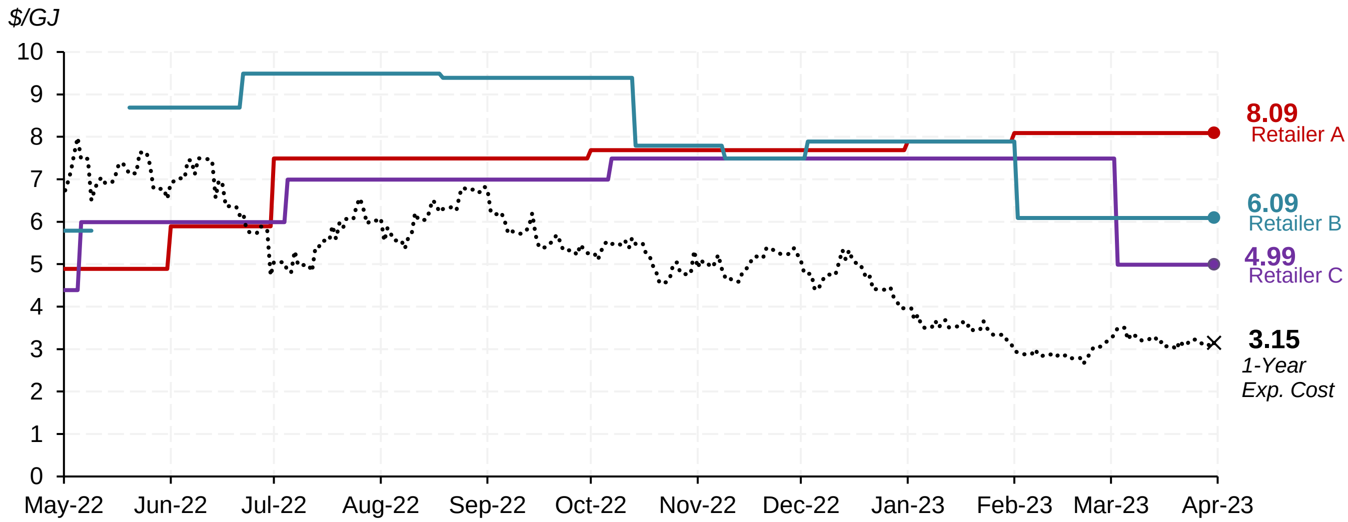
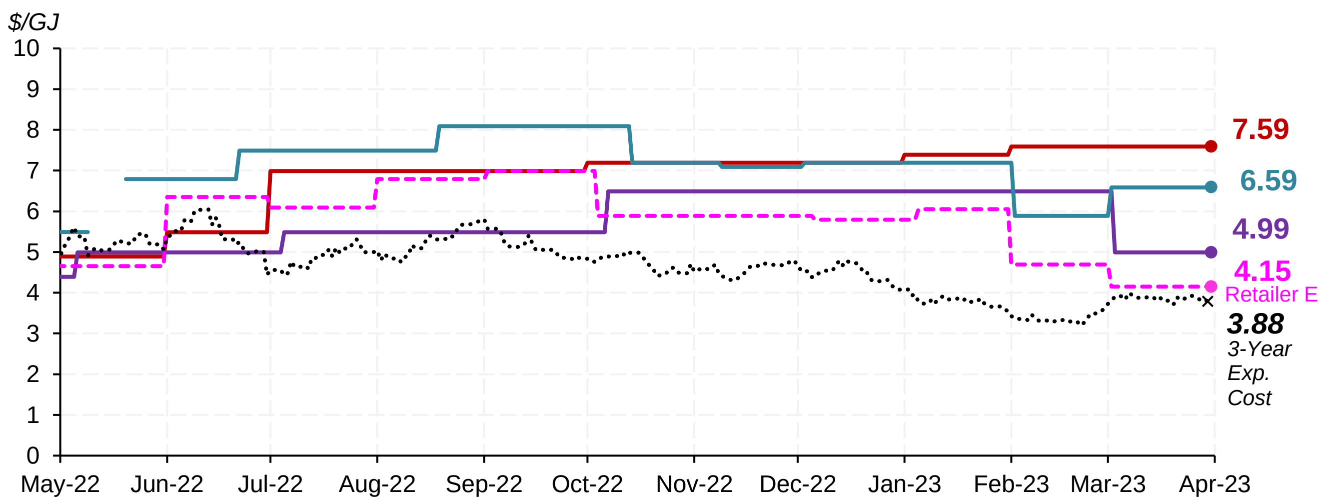


Figure 85: 1, 3, 5-year fixed rate natural gas contract prices, residential customers, ATCO Gas South service area (May 1, 2022 to March 31, 2023)





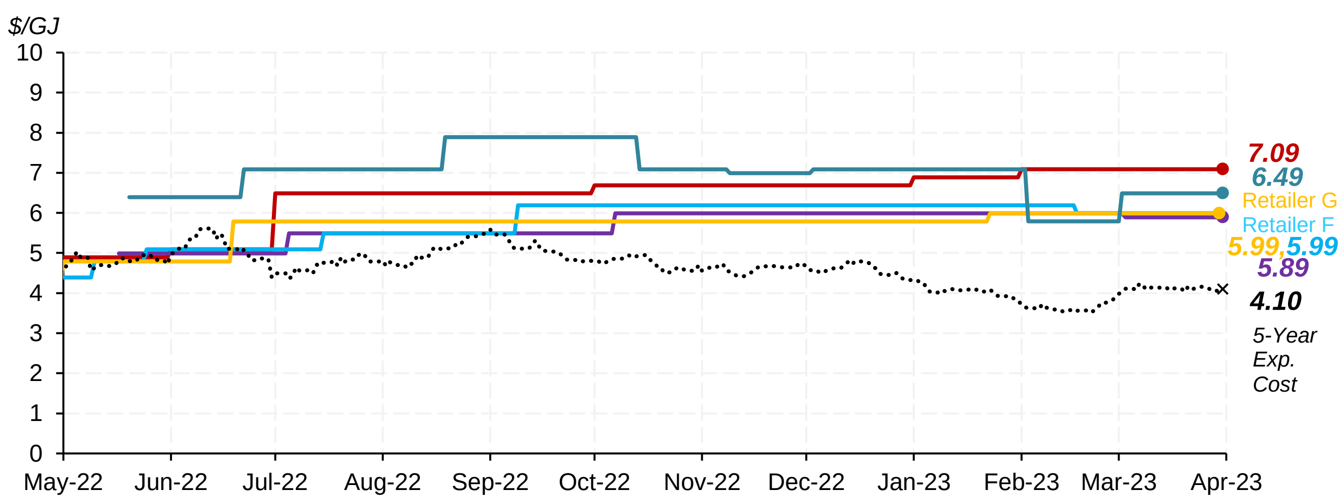


Table 23 shows the lowest 1-year, 3-year and 5-year competitive retail rates for electricity among select retailers as of January 1, 2022 and March 31, 2023. To put this in some context, an average residential customer on a 5-year fixed-rate electricity contract priced at 6.89 ¢/kWh would pay $35 less per month over the length of their contract than a customer on a 12.79 ¢/kWh 5-year plan.

Table 23: Lowest competitive fixed rates for electricity among select retailers (January 1, 2022 vs. March 31, 2023)

Contract Type	As of Jan 1, 2022 (¢/kWh)	As of Mar 31, 2023 (¢/kWh)	% Change
1 Year	7.99	14.1	**+76%**
3 Year	7.89	12.69	**+61%**
5 Year	6.89	12.79	**+86%**

Competitive fixed natural gas rates generally fell or stayed the same in Q1 2023 (Figure 85). The 5-year contract rates of different retailers were stable while a decline in rates occurred for shorter term contracts such as 1 and 3-year fixed rates.

5.3.2 Variable rates[43]

Competitive variable rates faced by residential electricity customers dropped in Q1 as the pool prices were moderate compared to Q4. The variable rates were 14.23 ¢/kWh in January, 13.94 ¢/kWh in February and 18.76 ¢/kWh in March. The average variable rate for Q1 was 35% less that the variable rates in Q4 2022. In all the months in Q1, variable rates were at a slight premium over RRO billing rates, due to the 13.5 ¢/kWh rate ceiling over the RRO (Figure 86). The premium was highest in March, when competitive variable rates were 5 ¢/kWh higher than RRO billing rates.

Competitive variable natural gas rates were lower than the DRT in January and February, contrary to Q4 2022 (Figure 87). However, competitive variable natural gas rates exceeded the DRT by $1.75/GJ in March.

[43] For the purposes of this section, “variable rates” refers to competitive rates that vary monthly and are tied to pool prices, not regulated rates.

Figure 86: Estimated competitive variable electricity rates vs. RRO, residential customers, ENMAX service area (Q1 2021 to Q1 2023)[44]

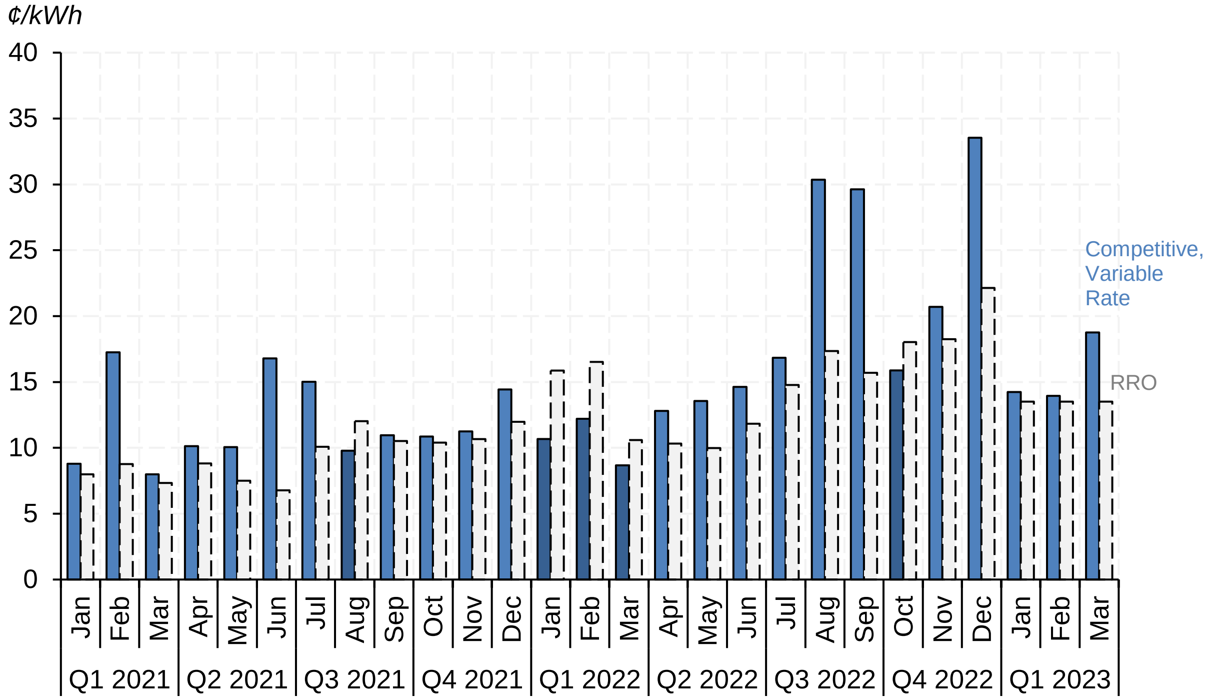
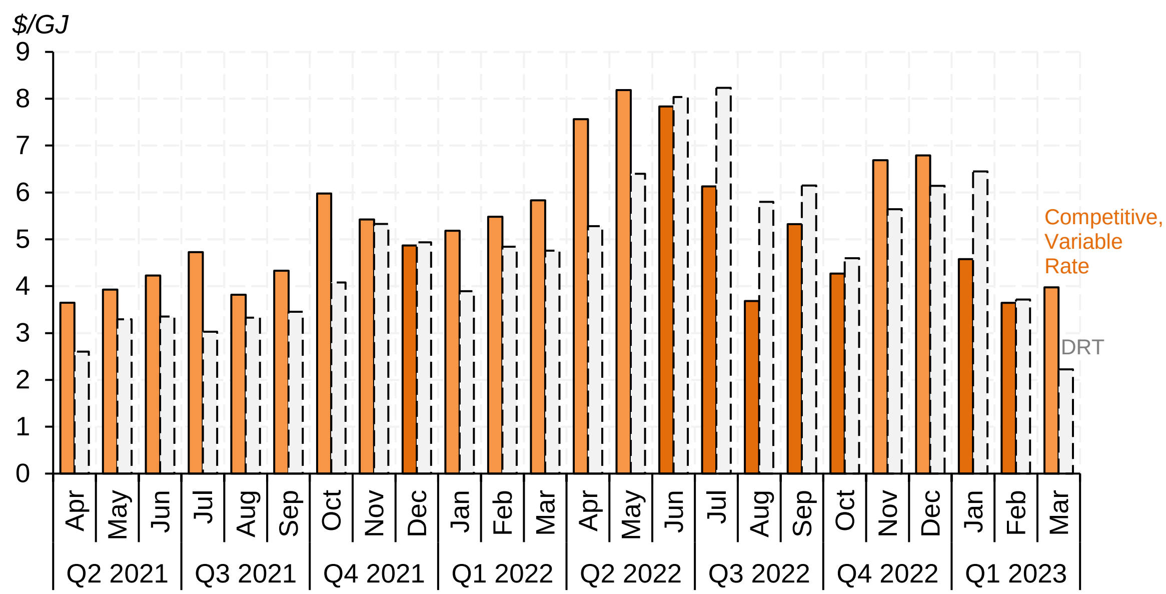


Figure 87: Estimated competitive variable natural gas rates vs. DRT, residential customers, ATCO Gas South service area (Q1 2021 to Q4 2022)[45]



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[44] Competitive variable electricity rates calculated as residential load-shaped pool price; includes a 1 ¢/kWh adder.

[45] Competitive variable natural gas rates calculated using the daily gas index; includes a $1/GJ adder.

5.4 Regulated retail rate estimates

5.4.1 Electricity regulated rate estimates

Expected residential RRO monthly rates (without accounting for the RRO ceiling in January, February and March 2023 and the addition of the collection rate thereafter) over the next 12 months have changed since January 2023 along with the volatility in forward prices (Figure 88). Compared to the MSA's January 2023 estimates, expected RRO rates have increased for summer and winter months such as July, August, December, and January but generally decreased for spring and fall months.

In December 2022, the Alberta legislature enacted the *Regulated Rate Option Stability Act* (RROSA). The RROSA places a ceiling on regulated electricity rates at a maximum of 13.5 cents/kWh for the months of January, February, and March 2023. Deferred revenue that results from this rate ceiling will be recovered through regulated rate customer bills over the period of April 2023 to December 2024. To recover this deferred revenue, a collection rate will be added to RRO monthly rates. The MSA refers to the total of these two rates as the “billing rate”.

The MSA has estimated the collection rates RRO residential customers could pay over the next twelve months. The collection rate estimation model considers estimated RRO site counts as of April 2023, monthly recovery amounts, and historical seasonal changes in residential RRO customer site counts to estimate the collection rates of each service area. The historical site counts in EPCOR service area indicates a 1% average month-over-month decline in RRO customers. Figure 89 shows the increase in the monthly RRO rates with the addition of collection rates.

Figure 88: May 2023 to April 2024 residential RRO monthly rate estimates, EPCOR service area (as of January 1, 2023 vs. April 1, 2023)

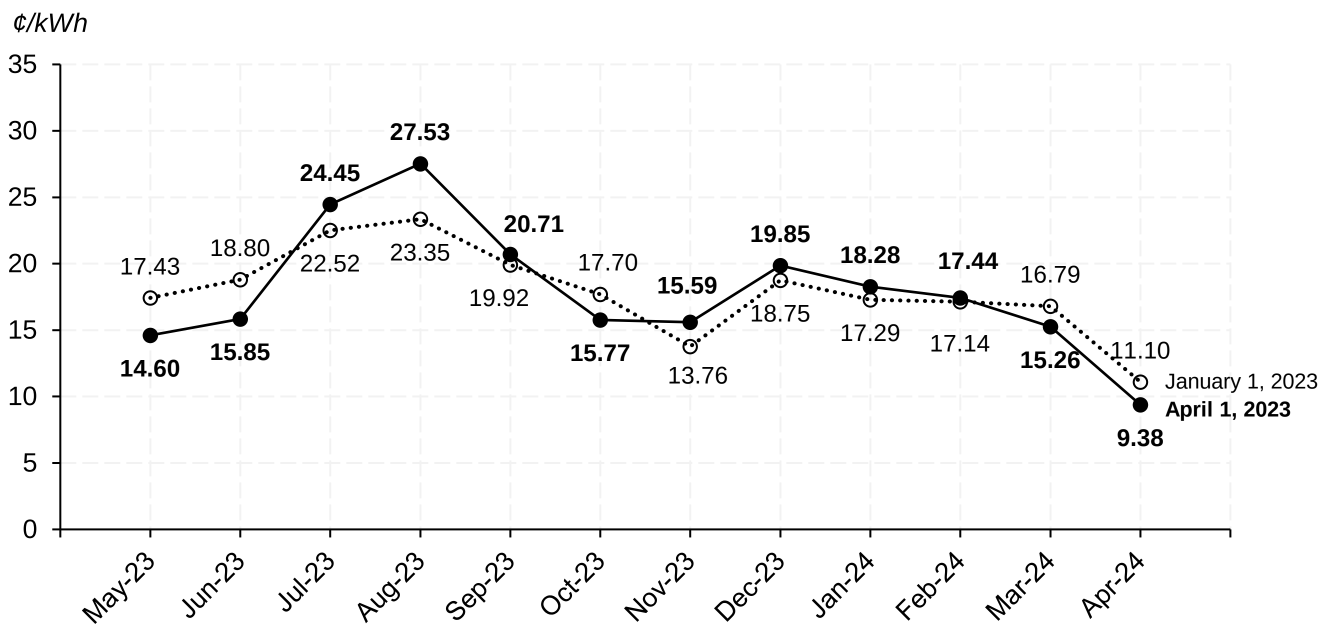
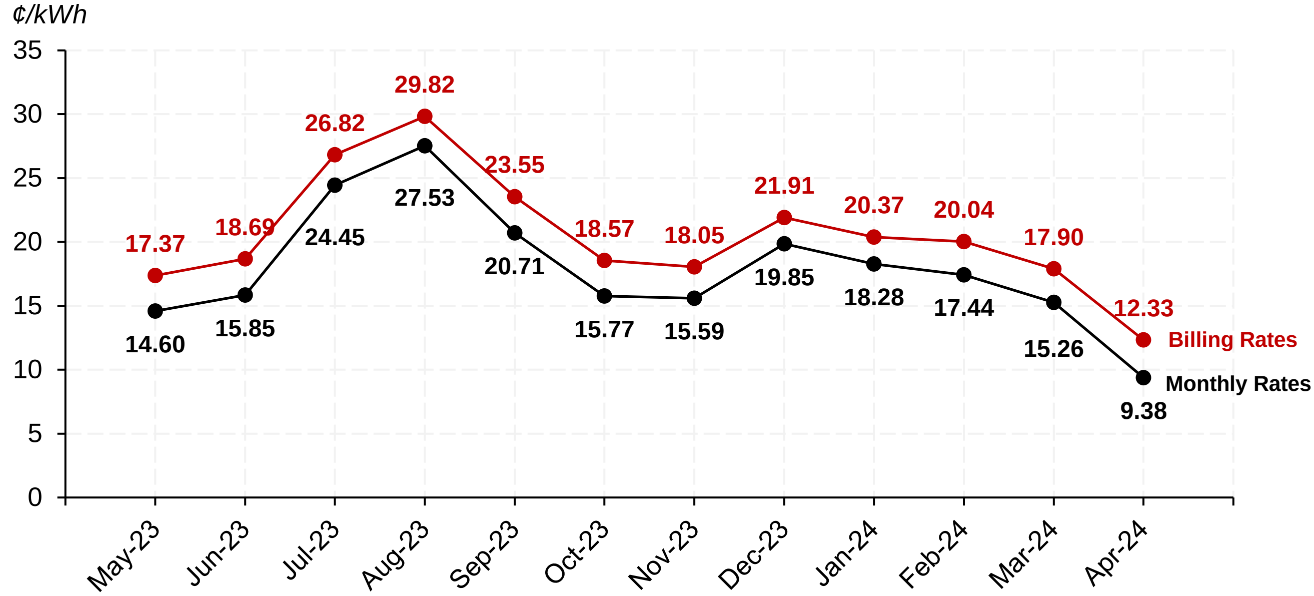


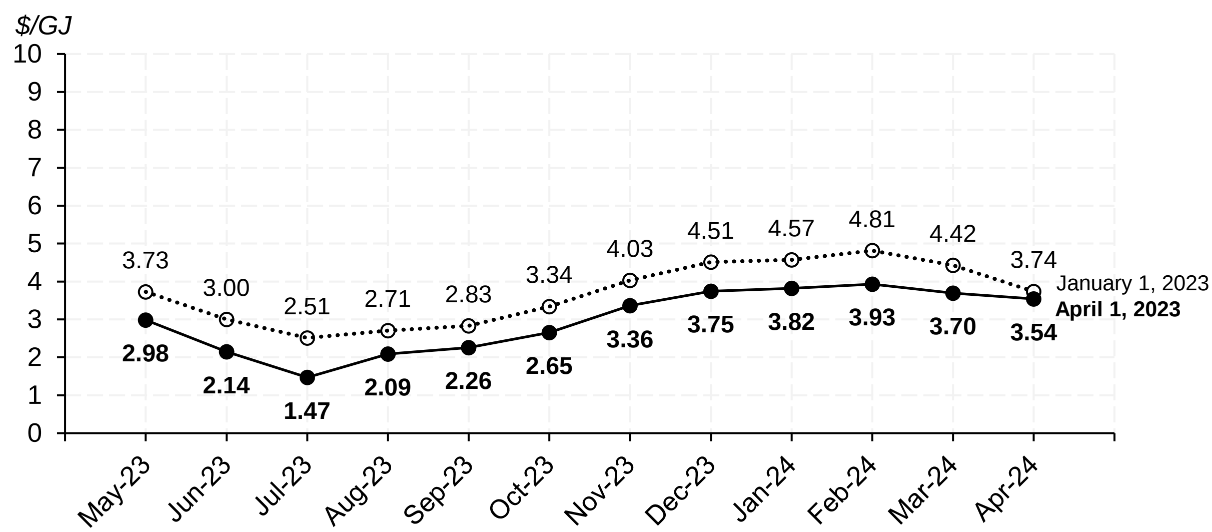
Figure 89: May 2023 to April 2024 estimated residential RRO monthly rates and billing rates, EPCOR service area (as of April 1, 2023)



5.4.2 Natural gas regulated rate estimates

Expected DRT rates for May 2023 to April 2024 months have decreased since the MSA's January 1, 2023 forecast (Figure 90). The decline in the natural gas futures prices in Q1 have driven this decline in residential DRT expectations. DRT rates are expected to fall by around $1/GJ relative to the previous forecast and remain well below the $6.50/GJ threshold for natural gas rebates by the Government of Alberta.

Figure 90: May 2023 to April 2024 residential DRT estimates, ATCO Gas service areas (as of January 1, 2023 vs. April 1, 2023)

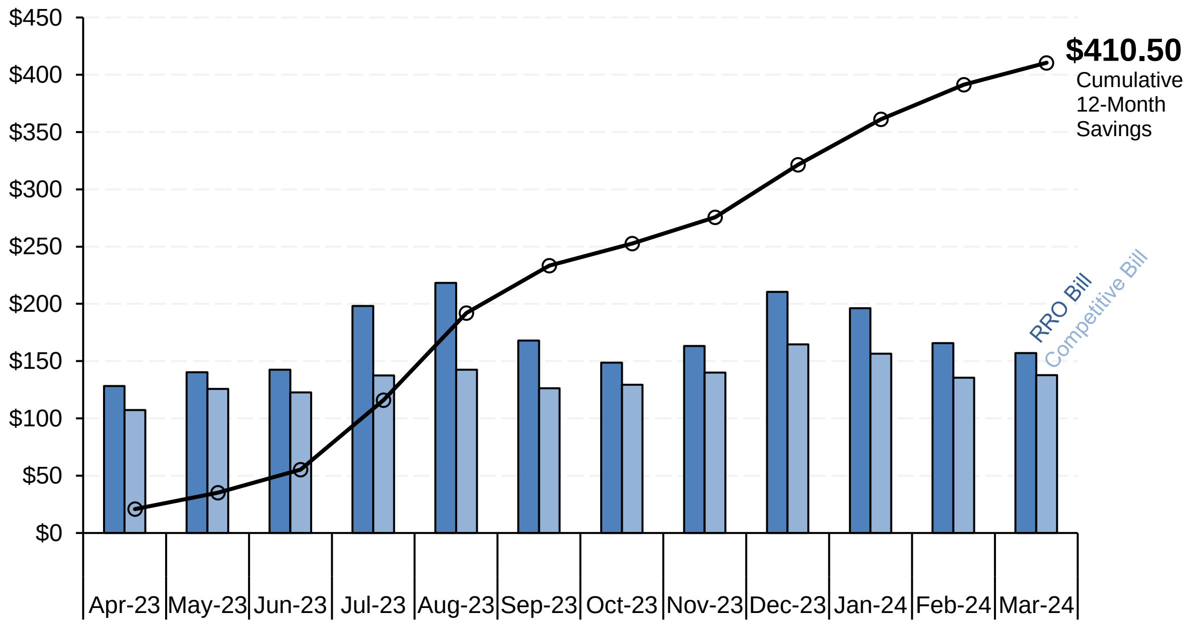


5.4.3 *Fixed rate switching incentives*

Though competitive fixed electricity rates increased over Q1, residential regulated retail customers still face strong incentives to switch to competitive fixed electricity rates given RRO rate expectations for the April 2023 to March 2024 period (Figure 91). An average residential RRO customer in the ENMAX service area could expect to save over $410 over 12 months had they switched to the lowest priced 3-year contract among contracts displayed in Figure 91 available on March 31, 2023.

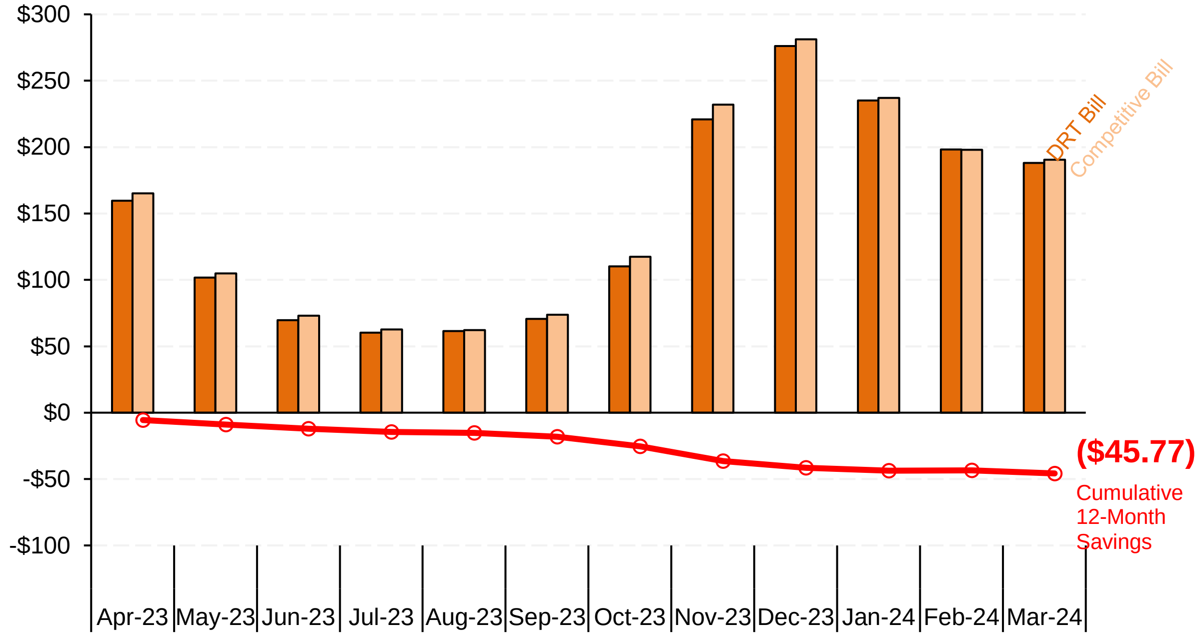
However, residential DRT customers may have an incentive to not switch to a competitive natural gas fixed rate as of April 1, 2023. If an average residential DRT customer had switched to the lowest 3-year natural gas rate on April 1, 2023, they could expect to pay around $91 more in the 12 months that followed (Figure 92). This incentive to not switch from DRT to a competitive natural gas fixed rate was $144 as of January 1, 2023. The decline in the switching disincentive is a result of the decline in competitive natural gas fixed rates when natural gas futures prices fell over Q1.

Figure 91: Expected RRO bill vs. competitive electricity bill (3-year fixed rate at 12.69 ¢/kWh, $6.85/month)[46]



[46] Estimated bills for a residential customer in the ENMAX service area over April 2023 to March 2024 period.

Figure 92: Expected DRT bill vs. competitive natural gas bill (3-year fixed rate at $4.15/GJ, $6.85/month)[47]



[47] Estimated bills for a residential customer in the ATCO Gas South service area over the April 2023 to March 2024 period.

6 REGULATORY AND ENFORCEMENT MATTERS

6.1 Wash Trading Investigation

In Q1 2023 the MSA opened an investigation into the conduct of two market participants regarding potential contraventions of section 2 of the *Fair, Efficient and Open Competition Regulation*, relating to prearranging offsetting or wash trades. This matter related to electricity forward market trades that collectively resulted in no net change in the market participants' volumetric position but did result in changes in financial risk and cashflows. Based on available information, the MSA is satisfied that no contravention occurred, and has discontinued its investigation.

6.2 Regulated Rate Option Stability Act

In December 2022, the Alberta legislature enacted the *Regulated Rate Option Stability Act* (RROSA). The RROSA placed a 13.5 cents/kWh ceiling on regulated electricity rates for the months of January, February, and March 2023. Deferred revenue that resulted from this rate ceiling will be recovered through regulated rate customer bills over the period of April 2023 to December 2024.

Each Owner[48] was required to establish a deferral account with the approval of their Reviewing Agency to administer the recovery of the monthly amounts. For Owners whose regulated rate tariff is approved by the council of a municipality or the board of directors of a Rural Electrification Association (REA) and for the City of Medicine Hat's Electric Utility, the Reviewing Agency is the MSA. The combined total deferral amount for all REAs and municipalities for the January, February, and March 2023 deferral period was approximately $27.7 million.

In March 2023, the *Regulated Rate Option Stability Regulation* (RROS Regulation) was enacted under the RROSA. The RROS Regulation establishes how an Owner shall calculate an instalment amount each calendar month in the recovery period to recover the deferral amount and interest that resulted from the RROSA. The RROS Regulation also establishes what Owners shall include in an application to recover an instalment amount and the role of the Reviewing Agencies to review and approve applications.

In March 2023, the MSA approved April collection rates for REAs and municipalities for the recovery of the first instalment amounts. The MSA will continue to review applications from each REA and municipality monthly through the recovery period.

[48] "Owner" means (i) the owner of an electric distribution system, or (ii) if the owner makes arrangements under which one or more other persons perform any or all of the duties or functions of the owner, the owner and those one or more other persons. When referred to in this document, Owner also includes the City of Medicine Hat's Electric Utility.

7 ISO RULES COMPLIANCE

The purpose of the ISO rules is to promote orderly and predictable actions by market participants and to facilitate the operation of the Alberta Interconnected Electric System (AIES). The MSA is responsible for the enforcement of the ISO rules and endeavours to promote a culture of compliance and accountability among market participants, thereby contributing to the reliability and competitiveness of the Alberta electric system. If the MSA is satisfied that a contravention has occurred and has determined that a notice of specified penalty (NSP) is appropriate, then AUC Rule 019 guides the MSA on how to issue an NSP.

From January 1 to March 31, 2023, the MSA closed 58 ISO rules compliance matters, as reported in Table 24.[49] An additional 149 matters were carried forward to next quarter. During this period 22 matters were addressed with NSPs, totalling $32,750 in financial penalties, with details provided in Table 25.

Table 24: ISO rules compliance outcomes from January 1 to March 31, 2023

ISO rule	Forbearance	Notice of specified penalty	No contravention
201.7	1	5	-
203.3	13	3	-
203.4	4	-	-
203.6	5	3	-
205.6	2	4	4
301.2	1	-	-
304.3	2	-	-
306.5	-	1	-
502.5	1	-	-
502.6	2	1	-
502.8	-	5	-
502.9	1	-	-
Total	**32**	**22**	**4**

[49] An ISO rules compliance matter is considered to be closed once a disposition has been issued.

Table 25: Specified penalties issued between January 1 and March 31, 2023 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)							Total ($)	Matters
	201.7	203.3	203.6	205.6	306.5	502.6	502.8		
Air Liquide Canada Inc.	500							500	1
British Columbia Hydro and Power Authority							500	500	1
DAPP Power L.P.		500						500	1
Enel X Canada Ltd.	500			10,000				10,500	4
ENMAX Generation Portfolio Inc.		250						250	1
ENMAX Kettles Hill Inc.	500							500	1
Grande Prairie Generation Inc.		500						500	1
Mercer Peace River Pulp Ltd.	250							250	1
Powerex Corp.			750					750	1
Syncrude Canada Ltd.						250		250	1
TransAlta Corporation							5,000	5,000	4
TransAlta Energy Marketing Corp.			250					250	1
TransCanada Energy Sales Ltd.			5,000					5,000	1
Voltus Energy Canada Ltd.				7,500				7,500	2
Windrise Wind LP					500			500	1
Total	1,750	1,250	6,000	17,500	500	250	5,500	32,750	22

The sections of the ISO rules listed in Table 24 and Table 25 are contained within the following categories:

201 General (Markets)
203 Energy Market
205 Ancillary Services Market
306 Outages and Disturbances
502 Technical Requirements

8 ARS COMPLIANCE

The MSA has the jurisdiction to assess whether or not a market participant has complied with Alberta Reliability Standards (ARS) and apply a specified penalty where appropriate.

The purpose of ARS is to ensure the various entities involved in grid operation (legal owners and operators of generators, transmission facilities, distribution systems, as well as the independent system operator) are doing their part by way of procedures, communications, coordination, training and maintenance, among other practices, to support the reliability of the AIES. ARS apply to both market participants and the AESO. ARS are divided into two categories: Operations and Planning (O&P) and Critical Infrastructure Protection (CIP). The MSA's approach to compliance with ARS is focused on promoting awareness of obligations and a proactive compliance stance. The MSA has established a process that, in conjunction with AUC rules, provides incentives for robust internal compliance programs, and self-reporting.

In accordance with AUC Rule 027, NSPs for CIP ARS contraventions are not made public, as well as any information related to the nonpayment or dispute of a CIP ARS NSP. CIP matters often deal with cyber security issues and there is concern that granular public reporting may itself create a security risk. As such, the MSA will only report aggregated statistics regarding CIP ARS outcomes.

From January 1 to March 31, 2023, the MSA addressed 25 O&P ARS compliance matters, as reported in Table 26.[50] An additional seven matters were carried forward to next quarter. During this period, eight matters were addressed with NSPs, totalling $17,750 in financial penalties, with details provided in Table 27. For the same period, the MSA addressed 42 CIP ARS compliance matters, as reported in Table 28, and four matters were addressed with NSPs, totalling $7,000 in financial penalties. An additional 90 matters were carried forward to next quarter.

[50] An ARS compliance matter is considered closed once a disposition has been issued.

Table 26: O&P ARS compliance outcomes from January 1 to March 31, 2023

Reliability standard	Forbearance	Notice of specified penalty
EOP-001	1	-
EOP-011	1	-
FAC-008	7	3
PRC-001	-	1
PRC-002	2	-
PRC-005	6	4
Total	17	8

Table 27: Specified penalties issued between January 1 and March 31, 2023 for contraventions of O&P ARS

Market participant	Total specified penalty amounts by ARS ($)			Total ($)	Matters
	FAC-008	**PRC-001**	**PRC-005**		
Air Liquide Canada Inc.			2,250	2,250	1
AltaLink L.P., by its general partner, AltaLink Management Ltd.		2,500		2,500	1
Castle Rock Ridge, LP	2,250			2,250	2
Cenovus Energy Inc.			2,500	2,500	1
CNOOC Petroleum North America ULC			3,750	3,750	1
Milner Power Limited Partnership by its General Partner Milner Power Inc.	2,250		2,250	4,500	2
Total	4,500	2,500	10,750	17,750	8

The ARS outcomes listed in Table 26 and Table 27 are contained within the following categories:

EOP Emergency Preparedness and Operations
FAC Facilities Design, Connections, and Maintenance
PRC Protection and Control

Table 28: CIP ARS compliance outcomes from January 1 to March 31, 2023

Reliability standard	Forbearance	Notice of specified penalty
CIP-002	2	1
CIP-003	8	-
CIP-004	3	-
CIP-005	2	-
CIP-006	2	-
CIP-007	8	1
CIP-010	9	2
CIP-011	4	-
Total	38	4

The ARS outcomes listed in Table 28 are contained within the following categories:

CIP-002	BES Cyber System Categorization
CIP-003	Security Measurement Controls
CIP-004	Personnel & Training
CIP-005	Electronic Security Perimeter(s)
CIP-006	Physical Security of BES Cyber Systems
CIP-007	System Security Management
CIP-010	Configuration Change Management and Vulnerability Assessments
CIP-011	Information Protection