MARKET SURVEILLANCE ADMINISTRATOR

Quarterly Report for Q3 2024

November 13, 2024

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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THE QUARTER AT A GLANCE

- **Market fundamentals drive decline in average pool prices year-over-year:** the average pool price in Q3 was $55.36/MWh, a decline of 63% relative to Q3 2023. Despite higher demand in Q3 this year, lower pool prices were driven by the addition of Cascade 1 and 2, increased intermittent generation supply, and lower natural gas prices.

- **Alberta becomes double peaking system**: demand in July was elevated, driven by high ambient temperatures and increased air conditioning load. Hourly demand in July was above the previous summer demand peak on 73 different occasions. The new summer peak of 12,221 MW is just 163 MW short of the winter demand peak set in January.

- **The AESO declared Energy Emergency Alert (EEA) on July 8:** between 20:25 and 21:34 on July 8 the AESO declared an EEA3 indicating that there was insufficient supply to reliably meet demand. The event was caused by relatively high demand, low wind generation, and some outages and derates on thermal generating assets. In addition, imports supply was reduced due to a transmission line outage which affected the BC/MATL intertie.

- **Frequency events during BC/MATL outage:** between September 23 and October 3 the BC/MATL intertie was offline for a planned outage. During this time intermittent generation was often high, resulting in low levels of inertia and primary frequency response. The AESO's event logs noted a high number of frequency deviations (a total of 28) in the 11 days the BC/MATL intertie was offline. At 19:54 on September 28 frequency fell to 59.53 Hz following a large trip at Cascade 1. For context, the AESO undertakes under-frequency load shedding when frequency falls to 59.50 Hz.

- **The secondary offer price limit was triggered in July:** in the first month after ISO rule 206.1 came into force, the cumulative revenue threshold was exceeded, which triggered offer price mitigation for gas assets of large firms. The MSA estimates that offer price mitigation reduced the average pool price in July by $8.13/MWh (8%). Mitigation was not triggered in August or September, resulting in an average pool price reduction of $2.74/MWh (5%) over Q3.

- **The AESO issued 13 Unit Commitment Directives (UCDs) in Q3:** under ISO rule 206.2, the AESO issued its first UCD on August 22. In total, 13 UCDs were issued in Q3, which the MSA estimates reduced average pool prices over the quarter by $3.63/MWh (6%). These UCDs reduced the frequency of low supply cushion events, and in one instance may have prevented an EEA event.

- **Extended supply surplus event**: on Saturday, August 24 the daily average pool price was $0.79/MWh, the lowest on record as the AESO declared a supply surplus event for over 17 hours from 02:50 to 20:10. This event was largely driven by low demand levels and high intermittent generation supply. In late September several similar days occurred such that the five lowest daily average pool prices all occurred in Q3.

- **System Variability and Unit Commitment**: in the first three quarters of 2024 there have been 24 hours of EEA events plus 335 hours at the price floor, occasionally in concert with outages on the interties. The combination of market circumstances has exposed system operational challenges not just related to ensuring energy to meet demand, but also in ensuring the system grid can perform within operational limits related to frequency, voltage, inertia, and other stability attributes. Many markets address these issues through a robust, hourly unit commitment model.

- **Transmission constraints increase**: in Q3, the volume of intermittent generation that was constrained down reached 125 GWh, a volume more than two times greater than Q3 2023. At least 1 MWh of intermittent generation was constrained down in 45% of hours in Q3. The constrained and unconstrained SMP differed by $1/MWh or more in 18% of hours in Q3, a marked increase when compared with year-over-year and quarter-over-quarter.

- **Total Operating Reserve (OR) cost increased:** high pool prices in July increased the average received prices for all OR products in Q3. This in turn raised the total OR cost by 79%, relative to the previous quarter. However, when compared to Q3 last year, both the received prices and total OR costs showed a decrease.

- **Low forward market liquidity:** Total trade volumes in Q3 were low at 6.18 TWh, which is similar to volumes in Q1 and Q2 but represents a 10% reduction compared to Q3 2023. This level of trading is historically low; it is comparable with the volumes observed in Q2 and Q3 of 2020 when market liquidity was reduced by uncertainty around the COVID-19 pandemic.

- **Low default electricity and natural gas rates:** The default electricity rates (the Regulated Rate Option, RRO) continued to be low in Q3. The monthly base RRO rate in Q3 was comparable with certain fixed-rate electricity contract prices. Default natural gas rates (Default Rate Tariff, DRT) in Q3 were the lowest on record.

- **Residential RRO customer loss was low**: The net loss in residential RRO customers was only around 7,000 in Q2 compared to 10,000 in Q1 and 38,000 in Q4 2023.

- **MSA compliance matters stable year to year:** From July 1 to September 30, 2024, the MSA closed 94 ISO rules compliance matters; 25 matters were addressed with notices of specified penalty. For the same period, the MSA closed 19 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; no matters were addressed with notices of specified penalty. In addition, the MSA closed 44 Alberta Reliability Standards Operations and Planning compliance matters; 23 matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Quarterly summary

The average pool price in Q3[1] was $55.36/MWh, a 63% decline compared to Q3 2023. Despite higher demand, pool prices were lower in Q3 this year because of increased supply. Available thermal capacity was 10% higher year-over-year due to new investment. Intermittent supply also increased, with wind generation increasing by 35% and solar generation increasing by 27%.

Natural gas prices were 74% lower year-over-year, decreasing input costs for thermal assets and putting downward pressure on pool prices.

Demand in July was 5% higher year-over-year, driven by high temperatures and increased air conditioning load. The previous summer peak set in June 2021 was exceeded 73 times in July due to record cooling loads. The new summer peak of 12,221 MW was set on July 22 in hour ending 17 (HE 17). This new record is 500 MW higher than the old summer peak and 163 MW short of the winter demand peak.

High demand combined with low wind generation on several days in July to increase pool prices. As a result, the *Market Power Mitigation Regulation* bound

Table 1: Summary market statistics for Q2 2023 and Q2 2024

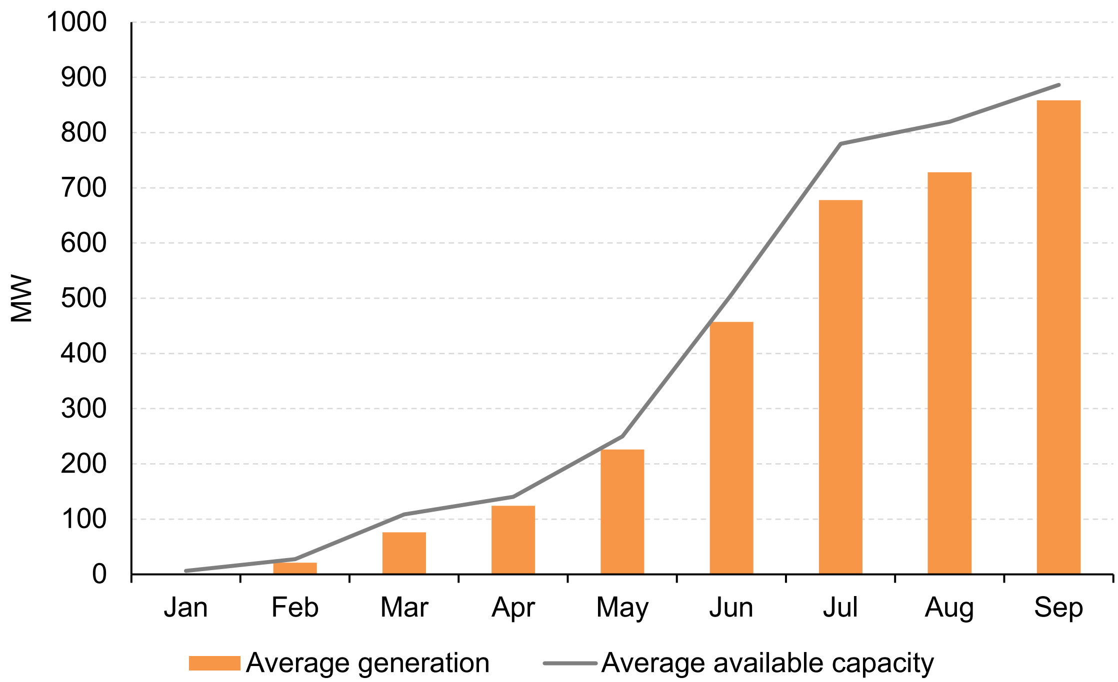
		2023	2024	Change
Pool price (Avg $/MWh)	July	$155.00	$88.62	-43%
	August	$186.80	$34.26	-82%
	September	$111.74	$42.80	-62%
	Q3	**$151.60**	**$55.36**	**-63%**
Demand (AIL) (Avg MW)	July	9,886	10,408	5%
	August	9,739	9,945	2%
	September	9,314	9,436	1%
	Q3	**9,650**	**9,935**	**3%**
Gas price AB-NIT (2A) (Avg $/GJ)	July	$2.42	$0.92	-62%
	August	$2.61	$0.58	-78%
	September	$2.44	$0.46	-81%
	Q3	**$2.49**	**$0.65**	**-74%**
Wind gen. (Avg MW)	July	761	1,040	37%
	August	815	1,114	37%
	September	1,039	1,367	32%
	Q3	**870**	**1,172**	**35%**
Solar gen. (Avg MW during peak hours)	July	619	800	29%
	August	560	706	26%
	September	461	575	25%
	Q3	**548**	**695**	**27%**
Net imports (+) Net exports (-) (Avg MW)	July	90	-185	-306%
	August	104	-418	-502%
	September	124	-212	-271%
	Q3	**106**	**-279**	**-363%**
Available thermal capacity (Avg MW)	July	9,317	9,935	7%
	August	9,111	10,169	12%
	September	8,636	9,575	11%
	Q3	**9,026**	**9,896**	**10%**

[1] Reference to Q2 means Q2 2024, reference to a month or date means the month or date in 2024.

on July 22 in HE 21. In addition, the AESO used the *Supply Cushion Regulation* for the first time on August 22 to direct online on assets that were on long-lead time. The impact of these regulations is analyzed in section 1.3.

Despite the higher demand in July, the average pool price fell by 43% relative to July 2023. One factor lowering prices in Q3 this year was the addition of the combined cycle assets Cascade 1 and 2 (maximum capability of 450 MW each). These assets came online in early 2024 and underwent commissioning until late June. In Q3, the capacity of these units was often available and they supplied a large amount of generation to the grid (Figure 1). For example, in September the average generation of Cascade 1 and 2 was 860 MW in total. This increase in supply put downward pressure on pool prices in the quarter.

Figure 1: Average available capacity and generation for Cascade 1 and 2 (January to September)



The price of natural gas continued to decline in Q3. The average price of natural gas over the quarter was \$0.65/GJ, which is a 43% decline relative to Q2, and a 74% decline compared to Q3 2023. The average price of natural gas in September was \$0.46/GJ, the lowest monthly average since 2001 (Figure 2). Natural gas assets set the System Marginal Price (SMP) 93% of the time in Q3. The lower price of natural gas put downward pressure on the costs of these generators and thereby lowered pool prices.

Average wind generation increased by 35% year-over-year and average solar generation during peak hours increased by 27% (Table 1). This growth in intermittent generation increases the volume of electricity supplied at \$0.00/MWh and puts downward pressure on prices. Figure 3 illustrates duration curves of intermittent generation in Q3 and Q3 2023. The upward shift in the distribution illustrates increasing supply year-over-year with the increase being between 400 MW and 600 MW for much of the distribution.

Figure 2: Monthly average price of natural gas (AB-NIT, real $)[2]
(January 2001 to September 2024)

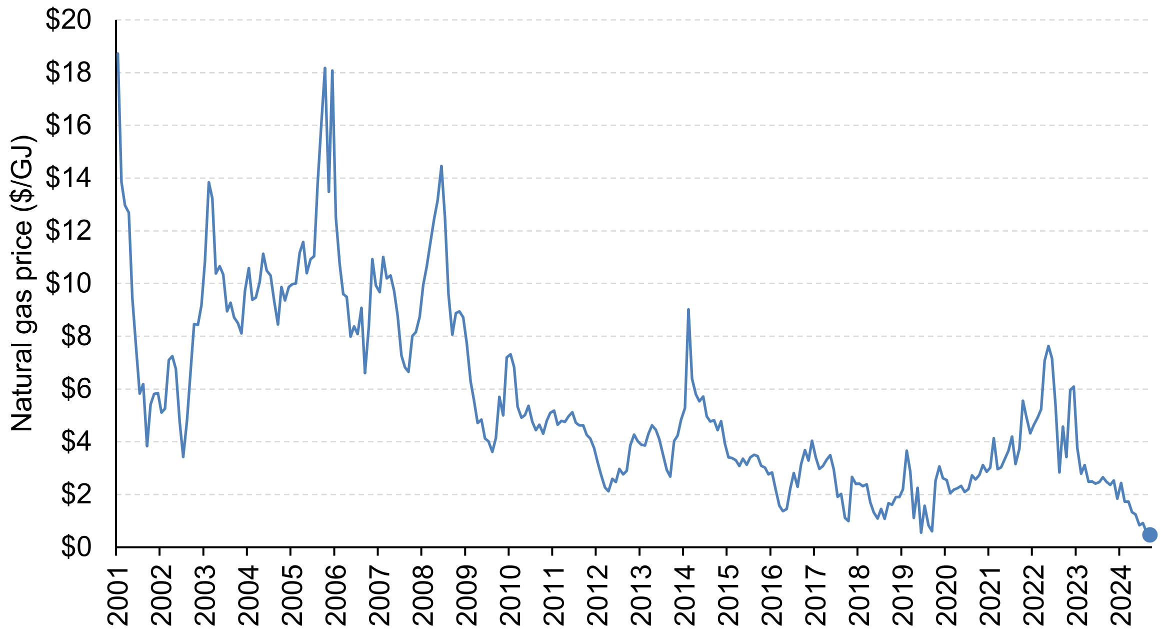
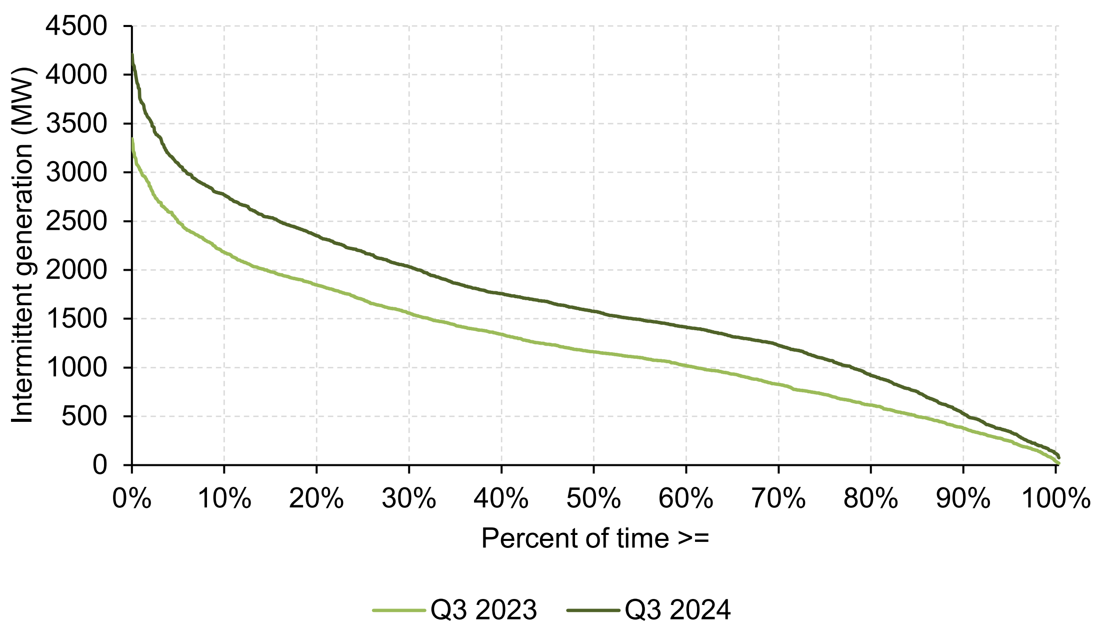


Figure 3: Duration curves of intermittent generation (Q3 2023 and Q3 2024)



[2] Adjusted for inflation using the monthly Consumer Price Index for Alberta, not seasonally adjusted.

1.2 Market outcomes and events

The average pool price in July was $88.62/MWh, the highest month in the quarter. A key factor was elevated demand driven by high temperatures. In addition, on many of the hot days in July wind generation was low.

Figure 4 illustrates average system load, net demand, and intermittent generation for each HE in July. Net demand is defined as system load less intermittent generation and illustrates the amount of demand left to be served by non-intermittent generation. While average system load in July peaked in HE 18, net demand peaked in HE 21 because of the amount of solar supplied in HE 18 to 20.

Figure 4: The composition of average net demand in July

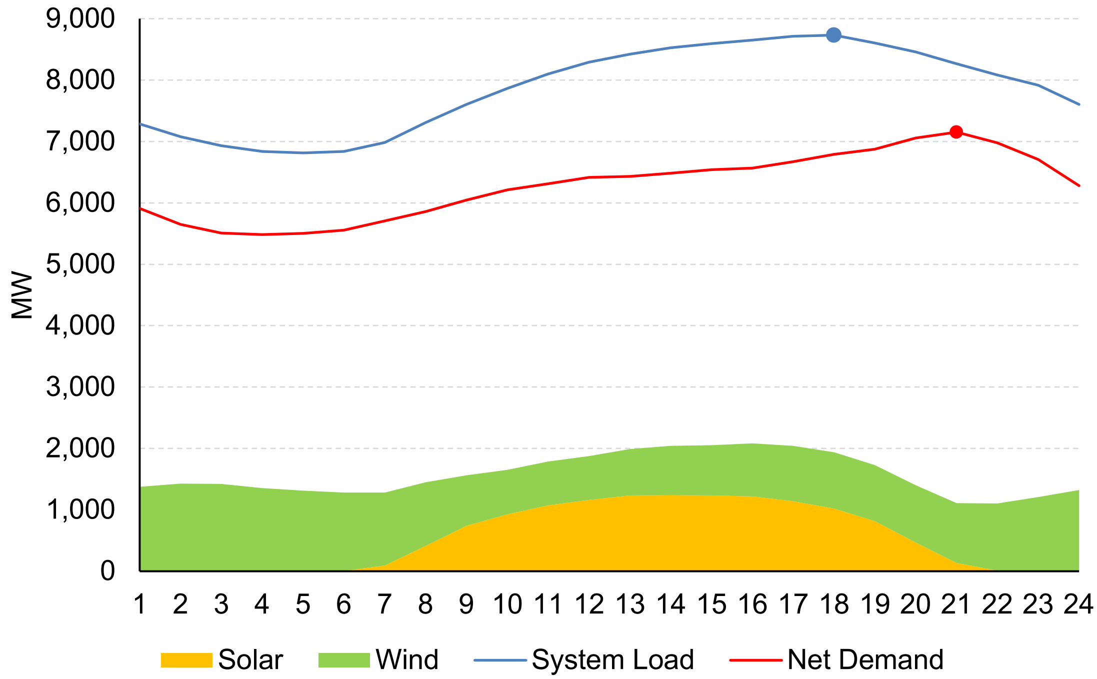


Figure 5 illustrates the average pool price by HE for each month in Q3. Prices in July were elevated for much of the afternoon and evening hours because of high temperatures and low wind generation on several days. The average pool price peaked in HE 21 in July, HE 20 in August, and HE 19 in September.

Figure 5: Average pool price by hour ending and month in Q3

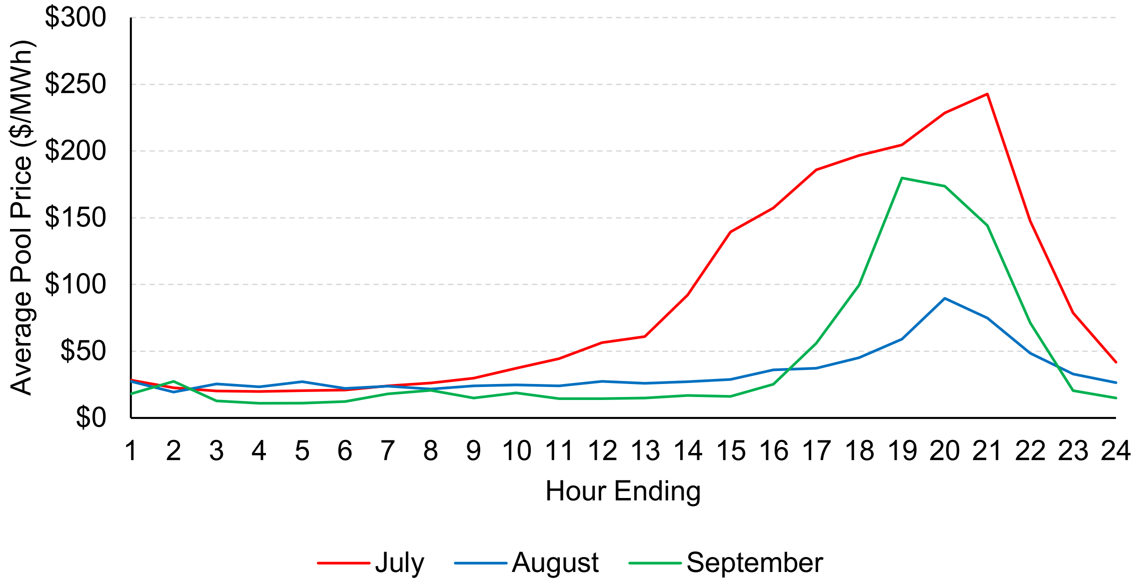


Figure 6 illustrates the distribution of SMP by month in Q3. The average pool price in July was higher than August and September largely due to higher prices in the top 20% of hours. The average price in September was higher than August due to higher prices in the top 10% of hours.

At the right end of the distribution, the SMP in September was $0.00/MWh for 9,306 minutes or 22% of the time, a new record (Figure 7). This result was driven by lower demand, high intermittent generation, and the must-run generation of thermal assets.

Figure 6: Duration curves of SMP by month in Q3

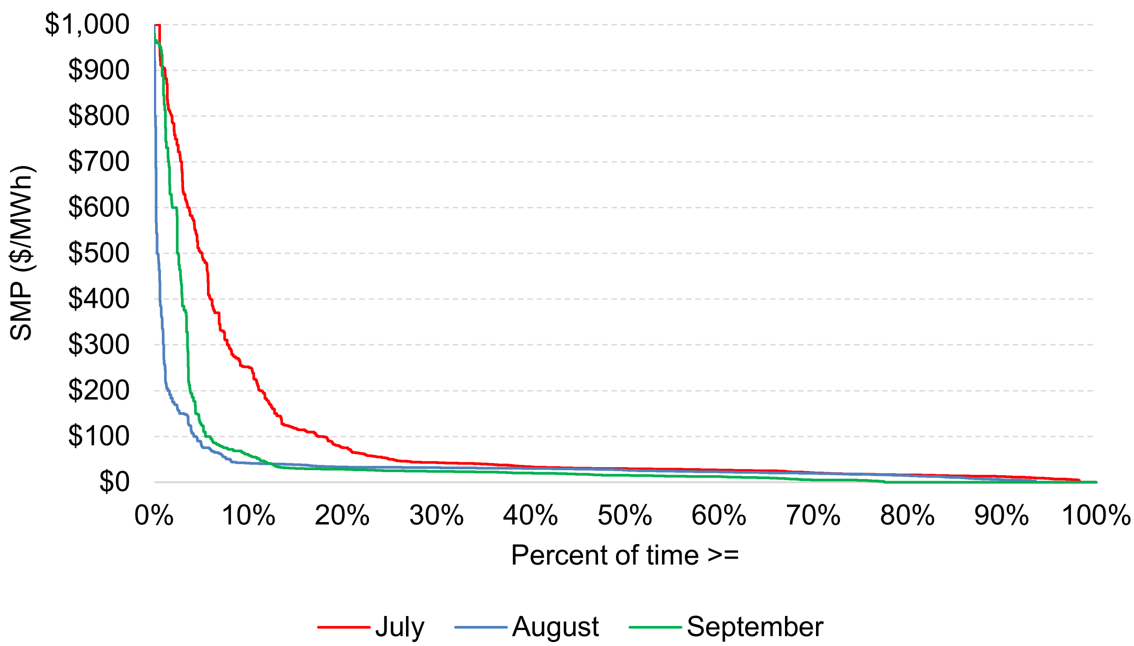
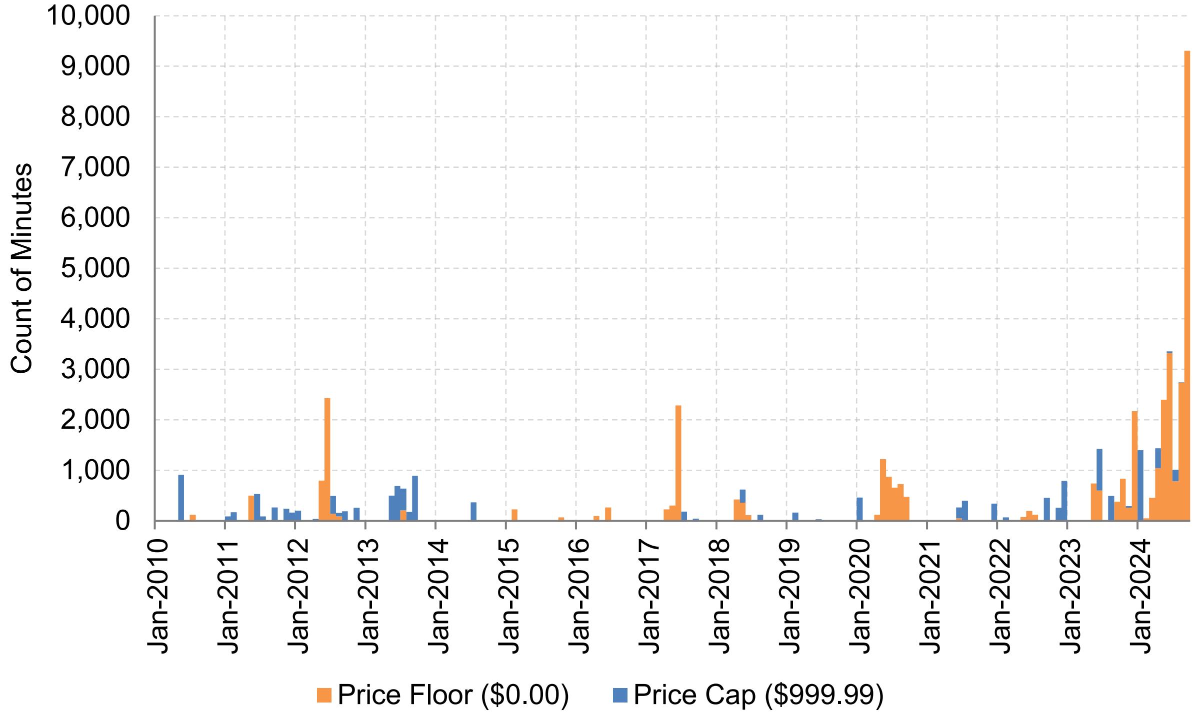


Figure 7: The number of minutes SMP was at the price floor and offer cap by month (January 2010 to September 2024)



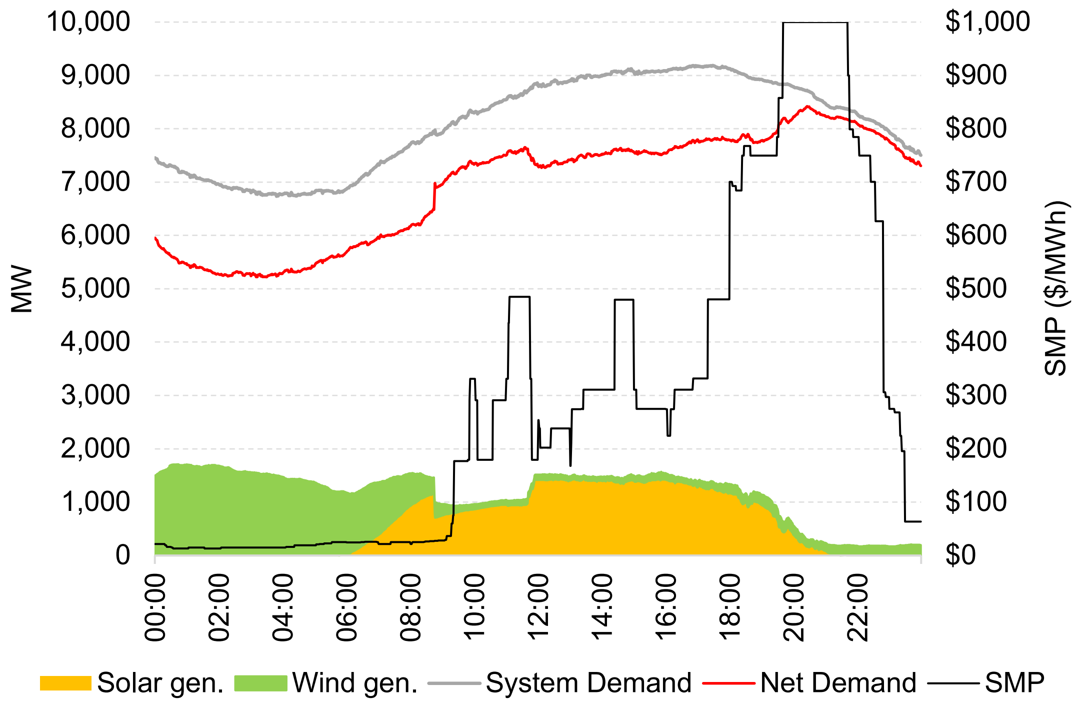
1.2.1 EEA event on July 8

On July 8, the AESO declared an Energy Emergency Alert level 3 (EEA3) from 20:25 to 21:34. This EEA declaration indicated that the AESO did not have sufficient supply to reliably meet demand. Demand on July 8 was relatively high, with Alberta Internal Load (AIL) peaking at 11,599 MW due to high temperatures. Temperatures in Calgary, Edmonton, and Fort McMurray peaked at 29°C, 32°C, and 28°C, respectively.

There was little wind generation over the peak so when solar generation declined in the evening intermittent generation was very low (Figure 8). In terms of thermal generation, Sheerness 2 (maximum capability of 400 MW) and Cloverbar 3 (maximum capability of 101 MW) were on outage while Cascade 1 and 2, and Shepard were all derated by around 100 MW. In addition, the Firebag asset (maximum capability of 497 MW) was derated to 80 MW due to wildfires in the area. The BC/MATL intertie was also derated to around 250 MW due to a line outage on 2L294. There were no assets commercially offline on long lead time during this event.

The EEA3 event ended at 21:34 as demand declined into the night hours.

Figure 8: System load, intermittent generation, net demand, and SMP (July 8, 2024)



1.2.2 Prices at the offer cap on July 10

On July 10 the SMP cleared at the offer price cap of $999.99/MWh from 19:00 to 20:16 due to high demand and thermal derates. On the demand side, AIL peaked at 12,122 MW due to high temperatures across Alberta (Table 2).

Table 2: Peak temperatures across Alberta on July 10

Location	Peak temperature (°C)
Calgary	34.2
Edmonton	35.6
Fort McMurray	34.7

In terms of supply, Cascade 1 and 2 (capacity of 450 MW each) were derated by around 200 MW each, Shepard (maximum capability of 868 MW) was derated by 110 MW, Cloverbar 3 (maximum capability of 101 MW) was offline, and Firebag (maximum capability of 497 MW) was derated to 215 MW. There were no assets commercially offline on long lead time.

Wind generation was relatively low over the net demand peak supplying around 580 MW. There was also a material reduction in solar supply at around 19:00 due to a fire at the Travers solar asset. The length of this event was shortened by wind generation, which increased into the evening hours.

1.2.3 *Prices at the offer cap on July 17*

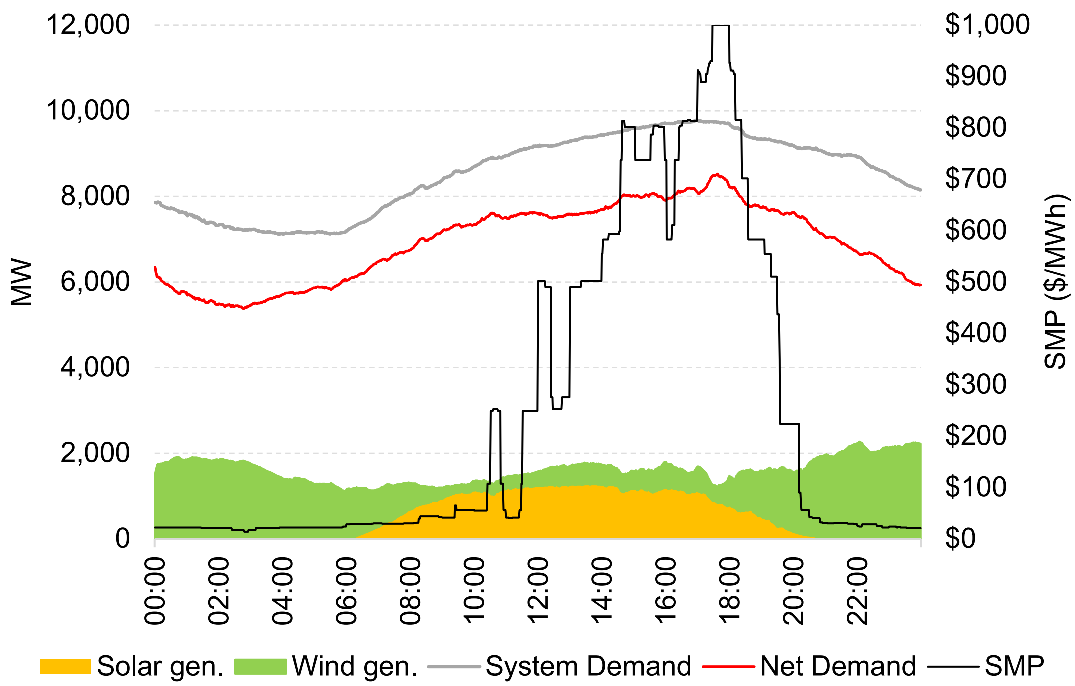
Prices also cleared at the offer cap on July 17 between 17:28 and 18:00. This is a relatively early time for prices to clear at the cap because solar generation was still high, averaging 830 MW.

Demand was high in this event, with AIL reaching 12,219 MW in HE 18 as peak temperatures were 31°C in Calgary, and 34°C in Edmonton and Fort McMurray.

On the supply side, Shepard (maximum capability of 868 MW) was derated by 105 MW and Firebag (maximum capability of 497 MW) was derated to 145 MW. In addition, imports were heavily constrained with import capacity on BC/MATL restricted to 12 MW due to a transmission line outage on 5L92. There were no assets commercially offline on long lead time for this event.

Wind generation during the peak was quite low averaging 460 MW while prices were at the offer cap. However, wind generation increased through the evening reaching 1,100 MW by 19:00 and 1,400 MW by 20:00 (Figure 9). This increase in wind generation served to limit the severity and length of this event as solar generation declined.

Figure 9: System load, intermittent generation, net demand, and SMP (July 10, 2024)



1.2.4 *SMP increases directly from price floor to offer cap on August 23*

At 22:53 on August 23, the SMP increased from $0.00/MWh immediately up to $999.99/MWh (Table 3). The SMP soon began to fall and was $0.00/MWh again by 23:00.

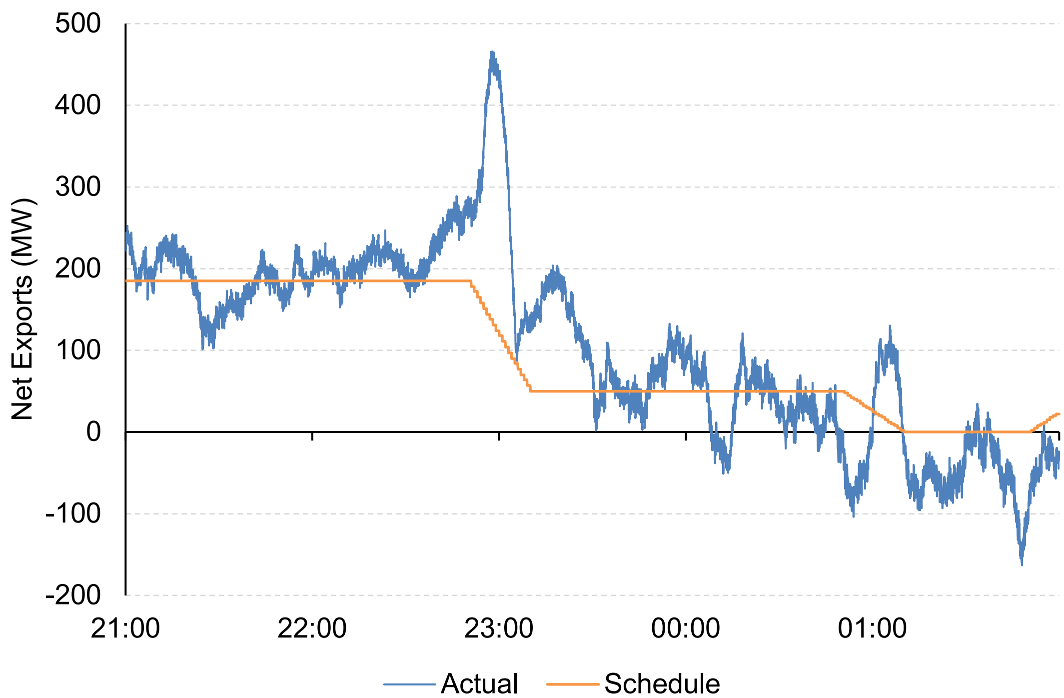
The SMP increase from $0.00/MWh up to $999.99/MWh resulted from a miscalculation by the AESO. The miscalculation stems from the fact that wind and solar generation are normally dispatched based on their available capability but in supply surplus situations they are dispatched based on their prevailing generation. Given that the actual generation of wind and solar is often quite a bit lower than their available capability, there is a large difference to overcome when dispatching out of supply surplus. As a result, the AESO's tools overestimated the amount of generation needed for dispatch and this led to the volume miscalculation.

Table 3: Select System Marginal Prices on August 23

Start time	End time	SMP ($/MWh)
22:00	22:53	$0.00
22:53	22:57	$999.99
22:57	22:58	$108.86
22:58	23:00	$32.82
23:00	23:53	$0.00

This miscalculation led to too much supply in Alberta and consequently to too many exports. Figure 10 shows actual and scheduled power flows on the BC intertie. At around 23:00 there was a spike in actual exports even as the schedule was declining. This spike in exports was the result of too much power supply in Alberta because of the volume miscalculation.

Figure 10: Actual and scheduled power flows in the BC intertie (August 23)



1.2.5 *Extended supply surplus on August 24*

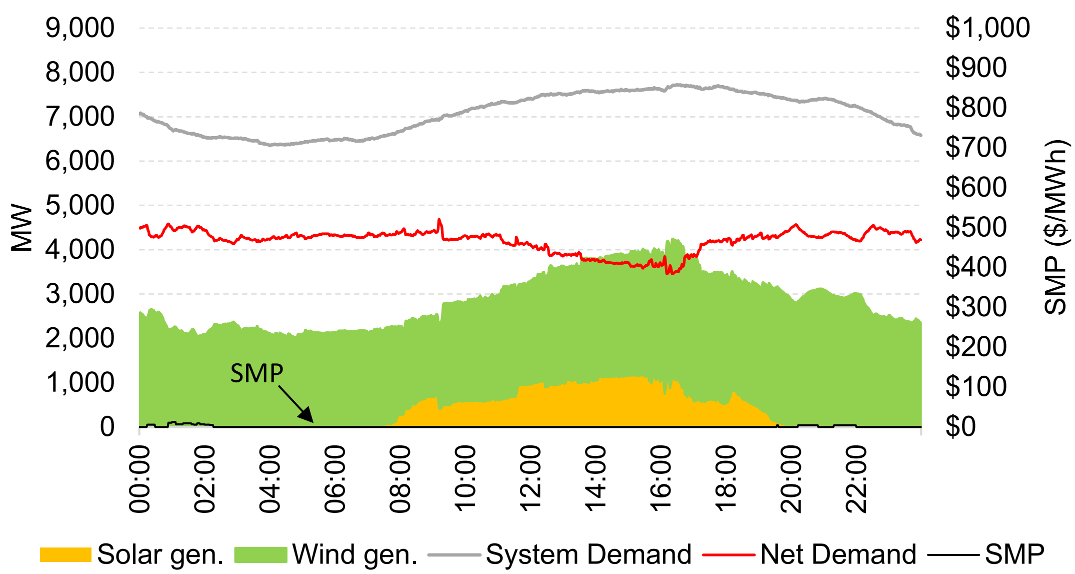
The average pool price on Saturday, August 24 was $0.79/MWh, the lowest recorded to date. Indeed, the five lowest average pool price days were all recorded in Q3 (Table 4). These low-priced days were largely the result of increased intermittent generation.

The low prices on August 24 were the result of consistently high wind generation and low demand levels (Figure 11). Wind generation averaged 2,501 MW over the day, the second highest in August, while AIL peaked at 10,246 MW, the second lowest in August. In addition, only Battle River 5 and Sheerness 1 were commercially offline on long lead time on August 24, increasing the supply of thermal generation at $0/MWh. Consequently, the AESO declared a supply surplus event that lasted more than 17 hours, from 02:50 to 20:10.

Table 4: The lowest daily average pool prices (January 1, 2001, to September 30, 2024)

Rank	Date	Average pool price ($/MWh)
1	Aug-24-2024 (Sat)	$0.79
2	Sep-29-2024 (Sun)	$1.33
3	Sep-27-2024 (Fri)	$2.53
4	Sep-25-2024 (Wed)	$3.28
5	Sep-26-2024 (Thu)	$5.35
6	Jun-09-2012 (Sat)	$5.61
7	Sep-09-2024 (Mon)	$6.18
8	Jun-30-2002 (Sun)	$6.46
9	Jun-16-2024 (Sun)	$6.57
10	Jun-10-2012 (Sun)	$6.71

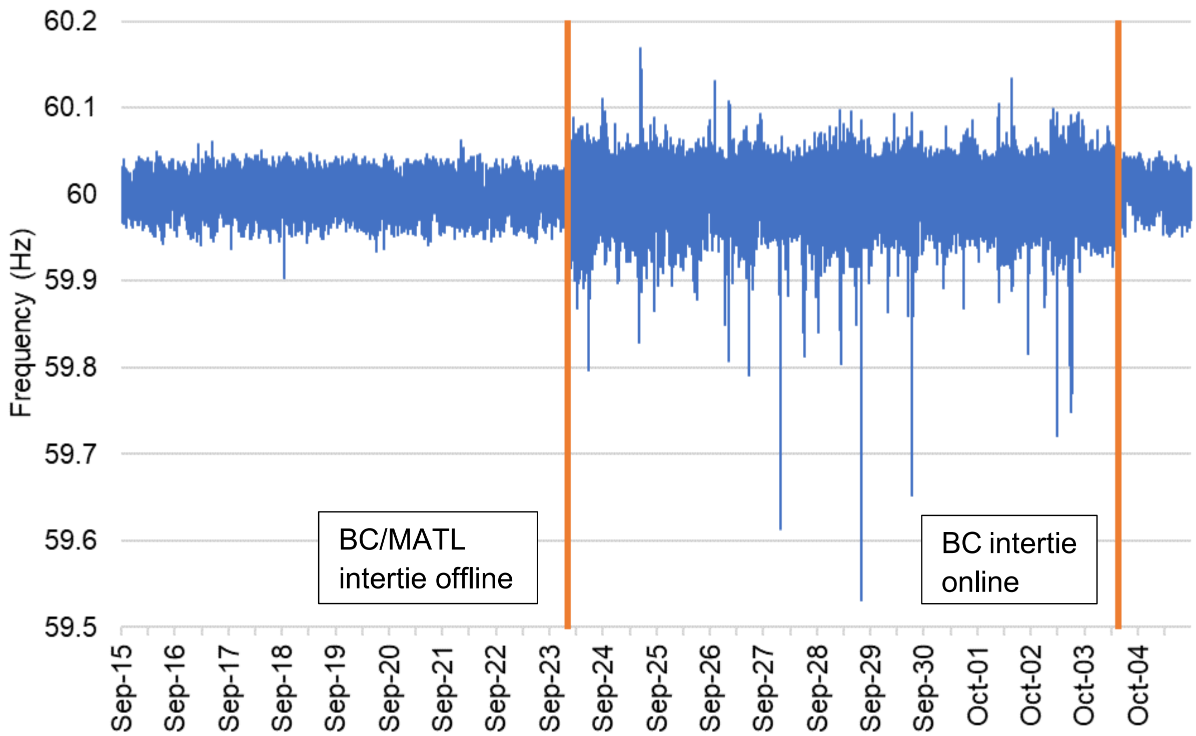
Figure 11: System load, intermittent generation, net demand, and SMP (August 24, 2024)



1.2.6 Frequency events in late September

Beginning on the morning of September 23, the BC/MATL intertie went offline for a planned outage with the BC line returning on the afternoon of October 3. When in service, the BC/MATL intertie acts as a shock absorber for contingency events and is increasingly relied upon by the AESO to maintain system frequency in Alberta. Even with arming load shed service (LSS) and fast frequency response (FFR) and procuring more regulating reserves than normal, frequency was more variable when the BC/MATL intertie was offline (Figure 12).

Figure 12: System frequency (September 15 to October 4; 2-second data granularity)



In total, the AIES event logs noted 28 frequency deviations over the course of the eleven-day BC/MATL outage.

The three largest frequency deviations occurred on September 27, 28, and 29. In all three events frequency fell below 59.7 Hz. The large frequency deviations on September 27 and 28 were caused by generation trips at Cascade 1 when the asset was supplying 450 MW (Figure 13 and Figure 14), close to the Most Severe Single Contingency (MSSC) limit of 466 MW. The large frequency deviation on September 29 was caused by a drop in wind generation (Figure 15).

On September 27 at 07:42:12, frequency fell to 59.615 Hz as Cascade 1 tripped with system load at 7,550 MW, intermittent generation at 3,400 MW, and the SMP at $0.00/MWh. Large amounts of intermittent supply lowered inertia and primary frequency response, and left the Alberta grid susceptible to large frequency deviations in the case of a contingency event while the BC/MATL intertie was offline. In this event around 100 MW of LSS or FFR tripped offline due to the decline in frequency.

On September 28 at 19:53:54, Cascade 1 tripped offline from 450 MW again and system frequency fell to 59.53 Hz. System load at the time was 6,900 MW and intermittent generation was 900 MW. Given the fall in frequency around 210 MW of LSS or FFR tripped offline as designed. The frequency deviation in this event came close to the Under Frequency Load Shed (UFLS) threshold of 59.5 Hz, although no firm load was shed.

Figure 13: Frequency and Cascade 1 generation (September 27)

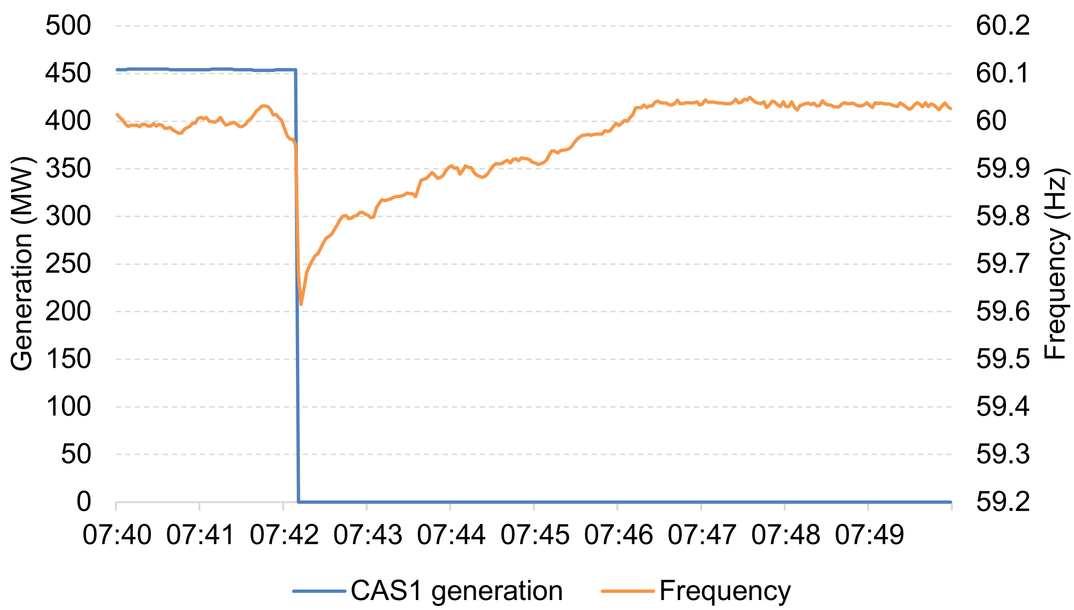
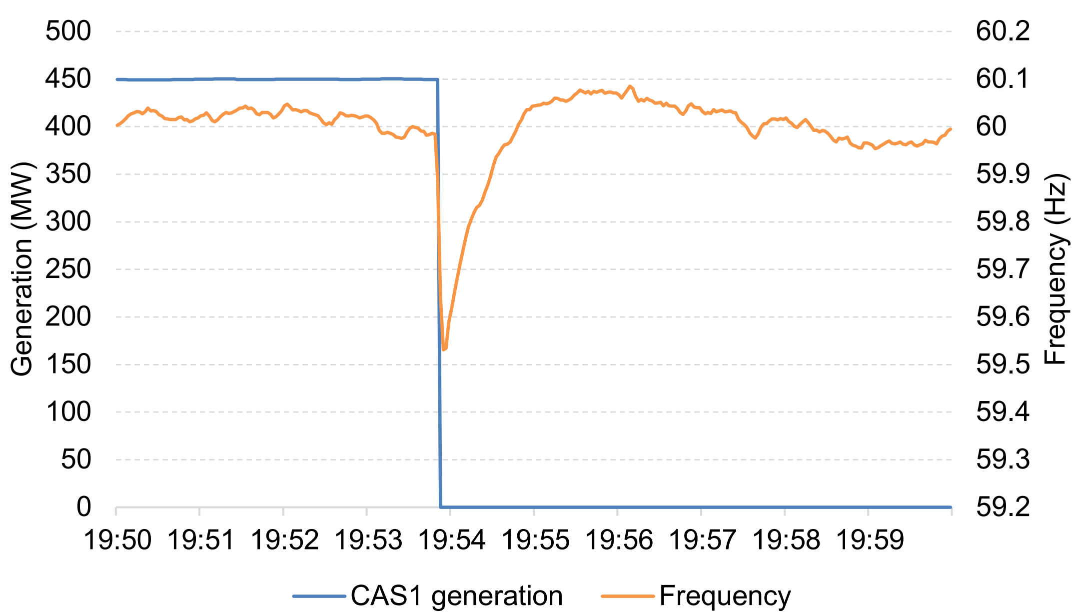
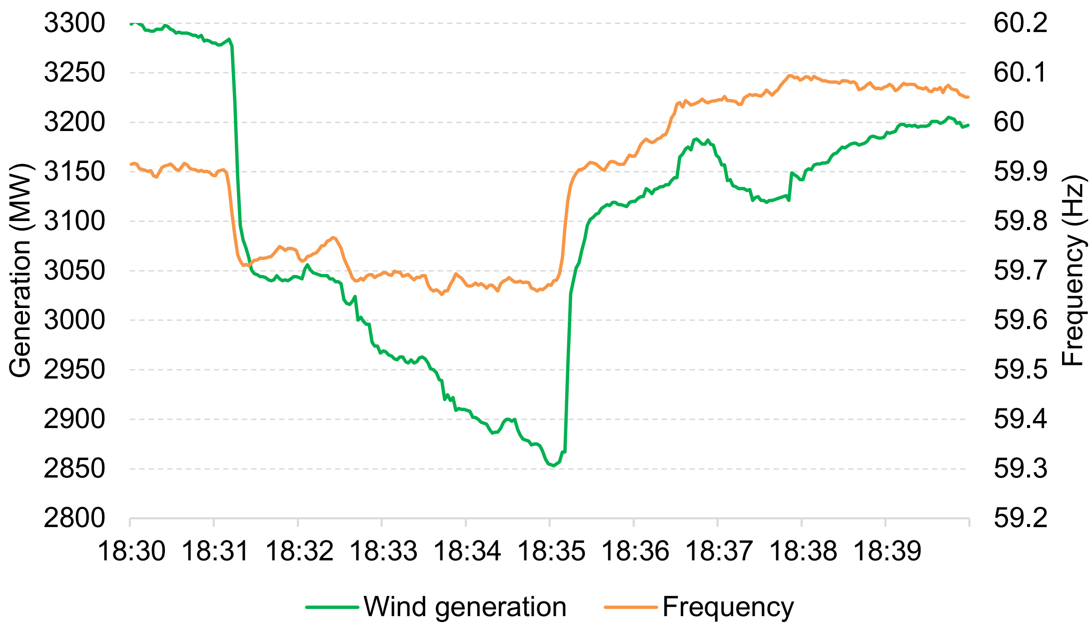


Figure 14: Frequency and Cascade 1 generation (September 28)



The large frequency deviation on September 29 was caused by a sudden drop in wind generation (Figure 15). This drop in generation largely occurred across the assets Sharp Hill Wind, Lanfine Wind, and Jenner 1 and 3. In total, wind generation dropped by around 200 MW over a 20-second period; from 3,280 MW at 18:31:00 to 3,080 MW at 18:31:20. In this instance, frequency did not recover quickly after it had dropped, but instead remained low for around four minutes before recovering as wind generation increased (Figure 15). Frequency hit a low of 59.65 Hz at 18:33:42.

Figure 15: Frequency and total wind generation (September 29)



1.3 Interim market power mitigation measures

In March 2024, the *Market Power Mitigation Regulation* (MPMR) and *Supply Cushion Regulation* (SCR) were enacted. Beginning July 1, 2024, these regulations moderate economic withholding and require the AESO to commit generation capacity under some circumstances. These regulations were informed by advice that the Minister requested from the MSA.[3] The MPMR and SCR are implemented through ISO rules 206.1 and 206.2, respectively. These rules are currently in force in their expedited form; full consideration of these rules under section 20.21 of the *Electric Utilities Act* is currently underway in Alberta Utilities Commission Proceeding 29093.

As noted in its advice, the MSA is of the view that the interim measures are necessary to support more effective competition in the transition period during the development and implementation of a full modern electricity market. The design of the interim measures was constrained by feasibility

[3] See the Advice from the MSA

of near-term implementation and should be replaced by industry best practices for market power mitigation and unit commitment as the AESO develops the Restructured Energy Market.[4]

This section sets out the MSA's observations regarding interim measures in Q3, their first quarter of operation. The MSA estimated the price effect of these measures. This analysis is described more in the following sections. In summary, the MSA estimates that the average pool price in Q3 would have been $61.73/MWh absent the interim measures. Compared to the observed average pool price of $55.36/MWh, this means the interim measures are estimated to have reduced the average Q3 pool price by $6.37/MWh or approximately 10%.

1.3.1 Market Power Mitigation Regulation and ISO rule 206.1

The MPMR is implemented through ISO rule 206.1, which moderates economic withholding by imposing a secondary offer price limit once monthly net revenues exceed a certain threshold.

The AESO must, on an ongoing basis, calculate the monthly net revenues that would be earned by a reference combined cycle generating unit. This value, called the monthly cumulative settlement interval net revenue (MCSINR), is updated each hour.

The AESO must also, on an annual basis, calculate the annualized unavoidable costs of the reference generating unit, defined as the sum of annualized capital investment costs (ACIC) and annual fixed operating costs (AFOC).

In any month, if the MCSINR exceeds 1/6 of the annualized unavoidable costs, the secondary offer price limit is triggered for the remainder of the month. This limit is the greater of either $125/MWh or 25 times the day-ahead natural gas price. The secondary offer price limit only applies to market participants with 5% or greater market share offer control and excludes renewable generation and storage. In effect, the limit applies to natural gas-fired generation of large market participants.

In Q3, the secondary offer price limit was triggered in July. In August and September, the MCSINR reached only 34% and 46% of the threshold, respectively, and accordingly the secondary offer price limit was not triggered.

1.3.1.1 July secondary offer cap event

The MCSINR calculated for HE 21 on July 21 exceeded 1/6 of the annualized unavoidable costs of the reference generating unit. As described in Section 1.1 above, high prices in July were primarily driven by several days of high demand and low wind generation. In this event, the AESO is required to determine the secondary offer price limit and notify pool participants in accordance with the *Market Power Mitigation Regulation* and ISO rule 206.1.

At 22:06 on July 22, the AESO reported via the Energy Trading System (ETS) that the secondary offer price limit was $125/MWh, effective July 23 HE 02 through July 24 HE 09. Additionally, at

[4] AESO Engage: Restructured Energy Market (REM) Technical Design

22:17, a message was issued to all Automated Dispatch and Messaging System (ADAMS) accounts, stating:

> “Secondary offer cap triggered. Secondary offer price limit effective starting HE02 July 23, 2024 for applicable pool participants.”

The AESO continued to report the secondary offer price limit and effective period through the end of July. This information was reported during HE 17 the day before it was effective, except for days where the effective period included Sunday or Monday, which was then reported the Friday before. The day-ahead natural gas price never exceeded $5/GJ, so the secondary offer price remained at $125/MWh through the end of July.

1.3.1.2 Price impact of the secondary offer cap

The MSA estimated the price impact of the secondary offer price limit in July. The analysis matches each mitigated hour with an unmitigated reference hour in which market fundamentals such as demand, intermittent renewable generation, and availability of large market participants’ portfolios were similar.

Offer behaviour in the unmitigated reference hour is used to reconstitute the offer prices of assets subject to the secondary offer price limit. The MSA has observed market participants shading their offers below the secondary offer price limit, so all offers from mitigated assets are reconstituted and not only the offers at the limit. A new system marginal price is determined using these reconstituted offers.

The analysis does not include second-order effects, such as demand response or changes in offer behaviour from unmitigated assets.

Table 5: Estimated price impact of the secondary offer price limit in Q3 2024

Time period	Actual average pool price ($/MWh)	Estimated unmitigated average pool price ($/MWh)	Percentage change (%)
July 23 HE 02 – July 31 HE 24	$35.34	$63.58	-44%
July 2024	$88.62	$96.75	-8%
Q3 2024	$55.36	$58.10	-5%

1.3.2 Supply Cushion Regulation and ISO rule 206.2

The SCR is implemented through ISO rule 206.2, which establishes a unit commitment mechanism for the AESO to direct long lead time (LLT) assets online.

The AESO must perform a forecast of supply cushion, called anticipated supply cushion (ASC), for each settlement interval. In Q3, the AESO made this assessment approximately every 5 minutes for settlement intervals in the next 24 hours and every hour for settlement intervals over the next 7 days.

If ASC falls below the threshold of 932 MW, the AESO must minimize, to the extent reasonable for the safe, reliable and economic operation of the interconnected system, the supply cushion deficit by issuing unit commitment directives (UCDs) to eligible LLT assets. Eligible LLT assets are assets that require more than one hour to synchronize to the grid. The AESO must determine which asset(s) to direct based on economic merit and physical constraints, which are informed by parameter submissions made by market participants to the AESO.

The AESO uses a tool called Power Optimisation (PowerOp) to determine the least cost UCD or combination of UCDs to minimize ASC deficits over the next 72 hours.[5]

When an asset is directed online, the effect of its generation on the pool price is not reconstituted, as required by the SCR. The asset is eligible to receive an uplift payment equal to the prudent incremental costs of responding to the UCD up to its minimum stable generation (MSG), net of pool price revenue.

1.3.2.1 Summary comments on unit commitment directives

In Q3, there were 13 UCDs, as listed in Table 6.

In every instance in Q3 when ASC was forecast below 932 MW at the time an eligible LLT unit would need to startup to address the deficit, a UCD was recommended. This suggests that PowerOp is correctly identifying when UCDs are required and making recommendations accordingly. While there were several instances of actual supply cushion below the threshold with no UCDs, these were either not anticipated in time to issue a UCD or there were no LLT assets offline.

In one instance, on August 31, UCDs may have been effective in preventing an EEA event. In HE 20, when supply cushion was 698 MW, SH2 was under a UCD and KH2 was still online following a UCD that ended after HE 19. The combined AC of these assets at the time was 790 MW, suggesting that an EEA event may have occurred without these assets online.

As the MSA highlighted in its report on recent system events[6] and its comments to the AESO on its strategic reserves proposal,[7] the ASC methodology has not effectively forecast supply adequacy. While increasing variability of generation has made forecasting more challenging, the MSA supports the AESO continuing to seek opportunities to improve this forecast.

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[5] Proceeding 29093 AESO IR responses to the MSA, 1(b) and 1(e), pg. 2-3

[6] Alberta electricity system events on January 13 and April 5, 2024: MSA review and recommendations, pg. 4

[7] MSA comments re AESO's strategic reserve proposal, pg. 6-7

Table 6: Unit commitment directives in Q3 2024

Asset ID	Commitment start time	Commitment end time	Minimum anticipated supply cushion	Minimum actual supply cushion
BR5	Aug 22 14:00	Aug 22 20:00	388 MW	1,006 MW
SH1	Aug 22 14:00	Aug 22 22:00	388 MW	1,006 MW
KH2	Aug 29 19:00	Aug 29 22:00	730 MW	589 MW[8]
KH2	Aug 31 17:00	Aug 31 19:00	647 MW	975 MW
SH2	Aug 31 19:00	Aug 31 23:00	491 MW	698 MW
KH2	Sep 15 16:00	Sep 15 18:00	625 MW	1,439 MW
SH2	Sep 15 18:00	Sep 15 22:00	478 MW	962 MW
BR5	Sep 15 18:00	Sep 15 23:00	478 MW	962 MW
BR5	Sep 16 14:00	Sep 16 18:00	922 MW	1,187 MW
BR5	Sep 16 18:00	Sep 16 22:00	670 MW	723 MW
BR5	Sep 17 05:00	Sep 17 09:00	920 MW	1,181 MW
KH2	Sep 19 16:00	Sep 19 18:00	858 MW	1,263 MW
KH2	Sep 20 08:00	Sep 20 10:00	848 MW	629 MW

1.3.2.2 Price impact of unit commitment directives

The MSA estimated the price impact of UCDs in Q3. The model removes assets under a UCD from the merit order and determines the new system marginal price. In instances when an asset came online early or remained online following a UCD, it is not removed from the merit order, as the asset was not compelled to be online at that time.

The model does not include second-order effects, such as demand response or offer behaviour changes from assets not under a UCD.

Table 7 shows the summary price effects. July is excluded because there were no UCDs issued in July.

[8] KH2 tripped offline while ramping in response to the UCD. The AC of KH2 surrounding the event was 390 MW, so minimum actual supply cushion would have been 979 MW if KH2 had successfully responded to the directive.

Table 7: Estimated price impact of unit commitment directives in Q3 2024

Time period	Actual average pool price ($/MWh)	Estimated average pool price without unit commitment directives ($/MWh)	Percentage change (%)
August 2024	$34.26	$39.00	-12%
September 2024	$42.80	$49.03	-13%
Q3 2024	$55.36	$58.99	-6%

1.3.2.3 Unit commitment directive events

This section describes the series of events surrounding the 13 UCDs issued in Q3.

August 22, 2024

- At 13:35 on August 21, the AESO forecast ASC below the threshold in HE 15-22 on August 22
- Minimum ASC was 388 MW
- BR5 and SH1 were on LLT
- PowerOp recommended UCDs to BR5 and SH1 from HE 15-20 and 15-22, respectively, on August 22
- The system operator accepted the UCD recommendations
- BR5 and SH1 both came online for the UCD and went offline again shortly after
- Actual supply cushion reached a minimum of 1,006 MW
- Average pool price over the UCD period was $65.57/MWh

August 29, 2024

- At 12:46 on August 29, the AESO forecast ASC below the threshold in HE 20-22 the same day
- Minimum ASC was 730 MW
- BR4, BR5, SH1, and SH2 were on LLT
- KH2 was online at MSG but was dispatched offline at 13:00
- PowerOp recommended a UCD to KH2 for HE 20-22
- The system operator accepted the UCD recommendation
- KH2 still went offline at 13:00, but came online again at 19:00
- While ramping, KH2 tripped offline at 19:43 and restated AC to 0 MW at 19:51
- KH2 briefly had positive AC and received a dispatch at 21:00, but restated back to 0 MW 2 minutes later
- Actual supply cushion reached a minimum of 589 MW in HE 20
    - With the 390 MW AC of KH2, supply cushion would have been 979 MW
- Average pool price during the UCD period was $188.33/MWh

August 31, 2024

- At 18:35 on August 30, the AESO forecast ASC below the threshold in HE 19-21 on August 31
- Minimum ASC was 491 MW
- BR5, KH2, SH1, and SH2 were on LLT
- PowerOp recommended a UCD to SH2 from HE 20-23 on August 31
- The system operator accepted the UCD recommendation
- That night, at 03:35 on August 31, PowerOp recommended a UCD to KH2 from HE 18-19 later that day
- The system operator accepted the UCD recommendation
- SH2 came online early at approximately 12:00, while KH2 came online in accordance with their UCD at 17:00
- Both assets stayed online after the UCD period
- Minimum actual supply cushion was 698 MW in HE 20
    - While KH2 was not under UCD in HE 20, it likely would have received a stay-on UCD if it had been dispatched offline after its UCD ended at 19:00
    - The combined AC of SH2 and KH2 was 790 MW, so this would have been an EEA event without these assets online
- Average pool price over the UCD period was $45.81/MWh

September 15, 2024

- At 17:35 on September 14, the AESO forecast ASC below the threshold from HE 17-23 on September 15
- Minimum ASC was 478 MW
- BR5, KH2, SH1, and SH2 were on LLT
- PowerOp recommended a UCD to SH2 for HE 19-22 on September 15
- The system operator accepted the UCD recommendation
- Shortly after, at 18:15, PowerOp recommended a UCD to BR5 for HE 19-23 on September 15
- The system operator accepted the UCD recommendation
- That night, at 02:35 on September 15, PowerOp recommended a UCD to KH2 for HE 17-18 later that day
- The system operator accepted the UCD recommendation
- SH2, KH2, and BR5 all came online earlier than required at around 08:20, 12:15, and 16:00, respectively
- All three assets stayed online after the UCD period ended, although KH2 was derated to 65 MW from 18:30 to 20:00
- Actual supply cushion reached a minimum of 962 MW in HE 20
- Average pool price over the UCD period was $32.45/MWh

September 16-17, 2024

- At 11:45 on September 16, the AESO forecast ASC below the threshold from HE 19-22 that same day
- Minimum ASC was 670 MW
- SH1 was on LLT
- BR5 was set to be dispatched offline at 12:00
- PowerOp recommended a UCD to BR5 for HE 19-22
- The system operator accepted the UCD recommendation
- At 11:55, PowerOp recommended a second earlier UCD to BR5, adding HE 15-18
- The system operator accepted the UCD recommendation
- At 12:00, BR5 stayed online and remained online through the UCD period
- Minimum actual supply cushion was 723 MW in HE 19
- Average pool price over the UCD period was $80.27/MWh
- BR5 went offline after the UCD ended at 22:00
- At 23:02, the AESO forecast ASC of 931 MW in HE 08 the following day (September 17)
- PowerOp recommended a UCD to BR5 from HE 05-09
- The system operator accepted the UCD recommendation
- BR5 came back online to meet the UCD and stayed online for the rest of September 17 before going back on LLT
- Minimum actual supply cushion during this second UCD period was 1,181 MW
- Average pool price during the second UCD period was $26.74/MWh

September 19-20, 2024

- At 02:35 on September 19, the AESO forecast ASC below the threshold in HE 18 later that day
- Minimum ASC was 858 MW
- BR5, KH2, and SH1 were on LLT
- PowerOp recommended a UCD to KH2 from HE 17-18
- The system operator accepted the UCD recommendation
- KH2 came online to meet the UCD and went back offline afterwards
- Minimum actual supply cushion was 1,243 MW, although it fell to 591 MW shortly after the UCD period due to KH2 going offline and lower than forecast intermittent generation
- Average pool price over the UCD period was $17.70/MWh
- At 18:35, the AESO forecast ASC of 848 MW in HE 09 on September 20
- PowerOp recommended another UCD to KH2 from HE 09-10
- The system operator accepted the UCD recommendation
- Between these UCDs, while KH2 was offline, Supply Surplus events occurred from 23:17 on September 19 to 00:10 on September 20
- KH2 came online to meet the second UCD and stayed online afterwards
- Minimum actual supply cushion was 629 MW, primarily due to lower than forecast intermittent generation
- Average pool price was $96.57/MWh

1.4 Market power and offer behaviour

1.4.1 Market power

The average pool price in Q3 was $55/MWh, which is $22/MWh higher than the MSA's estimate of average prices under a short-run marginal cost (SRMC). This $22/MWh mark-up over SRMC is low relative to historical values (Figure 16). For example, in Q3 2023 the average mark-up was $97/MWh, more than four times higher than in Q3.

The average mark-up in July was $38/MWh, the highest in the quarter. The average mark-up in August was $10/MWh, while in September it was $20/MWh. The higher mark-ups in July were driven by higher prices on several days with elevated demand and low wind generation.

Figure 16: Observed monthly average pool prices and counterfactual SRMC prices (January 2023 to September 2024)

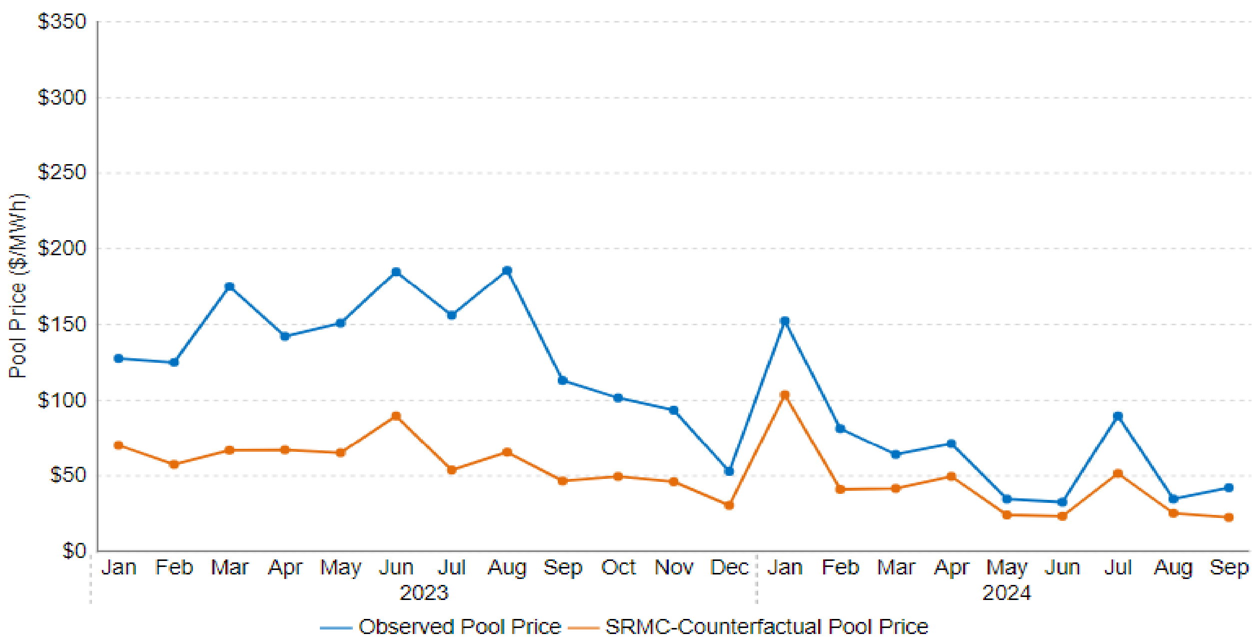


Figure 17 illustrates market-level pivotality by month going back to January 2023. A firm is pivotal when its withholdable[9] generation capacity is needed for the market to clear. The extent to which firms are pivotal in the market provides an indication of their ability to exercise market power. The levels of pivotality are as follows:

- two or more firms are individually pivotal at the same time ("two or more firms individually pivotal"),
- one firm by itself is pivotal ("one firm individually pivotal"),

[9] Withholdable generation capacity is all capacity except for Minimum Stable Generation and wind and solar capacity.

- two firms are collectively pivotal with their combined withholdable capacity ("two firms collectively pivotal"), and

- no firm is pivotal or collectively pivotal ("no firm pivotal").

The ability of companies to exercise market power in Q3 was highest in July when at least one firm was pivotal in 14% of hours, the highest since January. In August and September, at least one firm was pivotal in 1% and 4% of hours, respectively, which represents a material decline relative to August and September of 2023 (Table 8). The reasons for this include the additional supply of Cascade 1 and 2, increased intermittent generation, and mild weather in August.

Figure 17: Market level pivotality by month (January 2023 to September 2024)

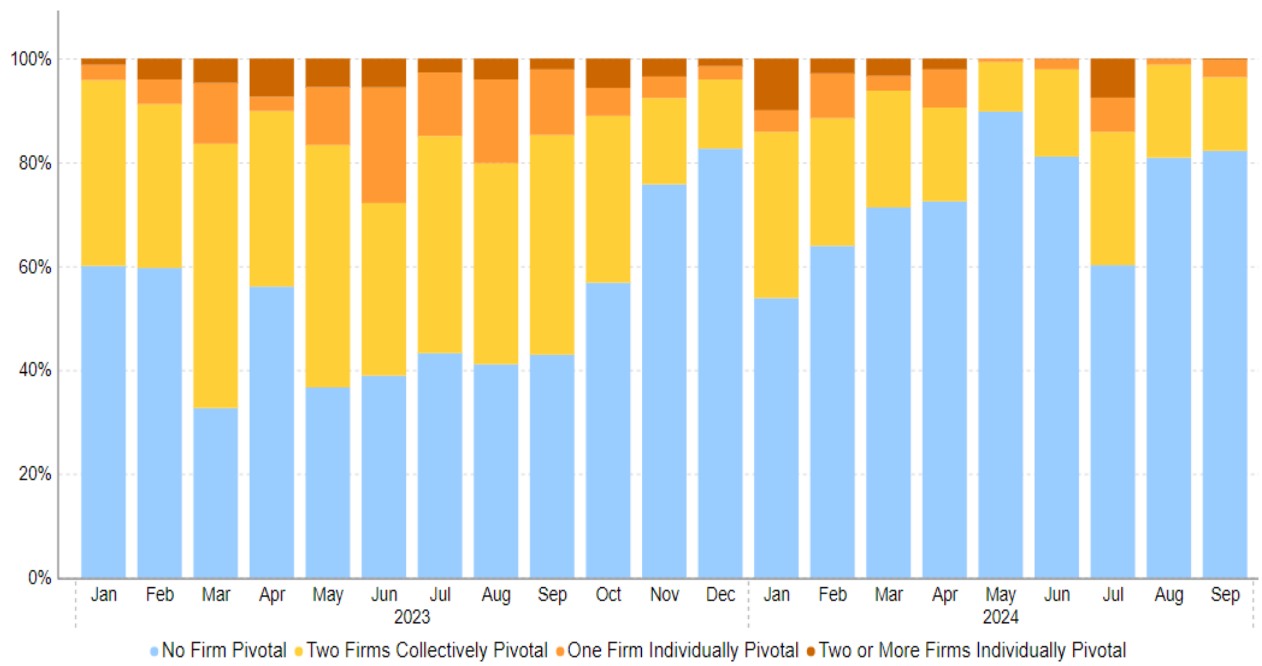


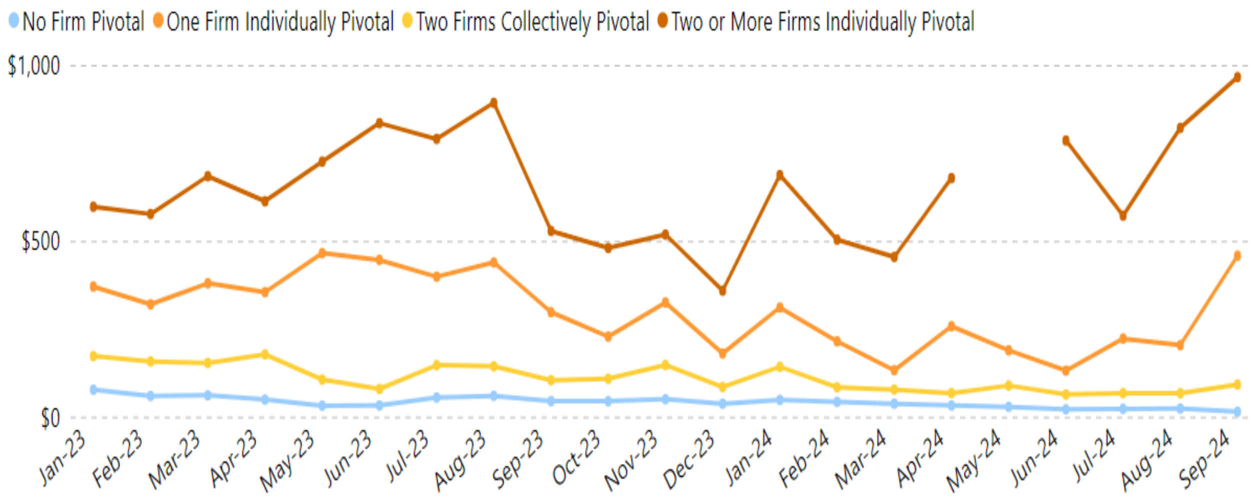
Table 8: Percentage of hours where at least one firm was pivotal (Q3 2023 and Q3 2024)

	2023	**2024**
July	15%	14%
August	20%	1%
September	15%	4%

In August no firm was pivotal in 81% of hours and two firms were only collectively pivotal in 18% of hours. As shown in Figure 18 prices tend to be low in these hours reflecting a large amount of supply relative to prevailing demand and low levels of market power.

Figure 17 and Figure 18 together illustrate that the lower prices observed in August and September this year were largely driven by the change in market fundamentals which reduced the ability of firms to exercise market power, rather than by less market power being exercised when firms were pivotal.

Figure 18: Average pool price by month and pivotality condition (January 2023 to September 2024)



The Lerner index measures market power by calculating the mark-up as a percentage of price:

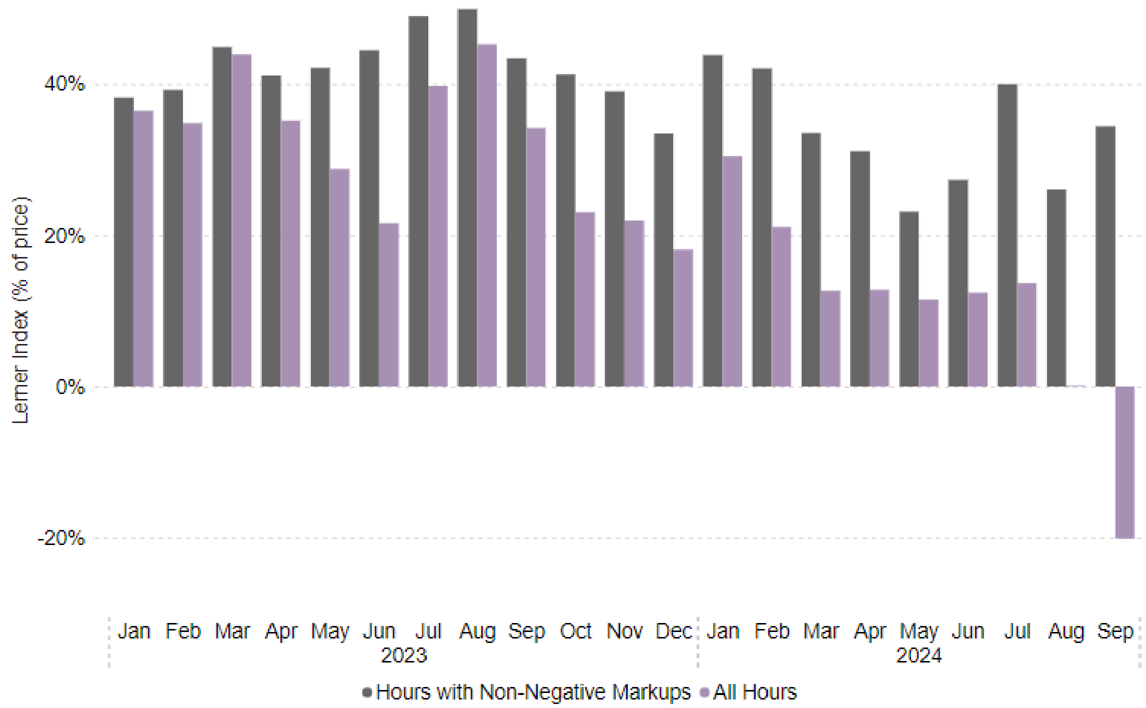
$$Lerner\ Index = \frac{(Price - SRMC)}{Price}$$

A higher Lerner index indicates greater mark-up and more market power. Figure 19 illustrates the average Lerner index by month since January 2023. In 40% of hours in the quarter the calculated Lerner index was negative indicating that prices in the SRMC counterfactual were higher than actual prices. This occurs when generation capacity is offered into the market below the MSA's estimate of SRMC for that asset.

The average Lerner index for all hours in August was 0%, reflecting hours with a negative Lerner index offsetting hours with a positive Lerner index. In September the average Lerner index for all hours was -20% reflecting many hours with a negative Lerner index. In September, the SMP settled at the price floor of $0.00/MWh in 9,306 minutes or 22% of the time. This was driven by lower demand, high amounts of intermittent generation supply, and thermal capacity being offered at $0.00/MWh.

Outside of these negative mark-ups, market power, as measured by the Lerner index, still declined year-over-year. Using hours with non-negative mark-ups, the average Lerner index in July fell from 49% to 40% year-over-year, in August it fell from 50% to 26%, and in September it declined from 43% to 34% (Figure 19).

Figure 19: Average Lerner index by month (January 2023 to September 2024)

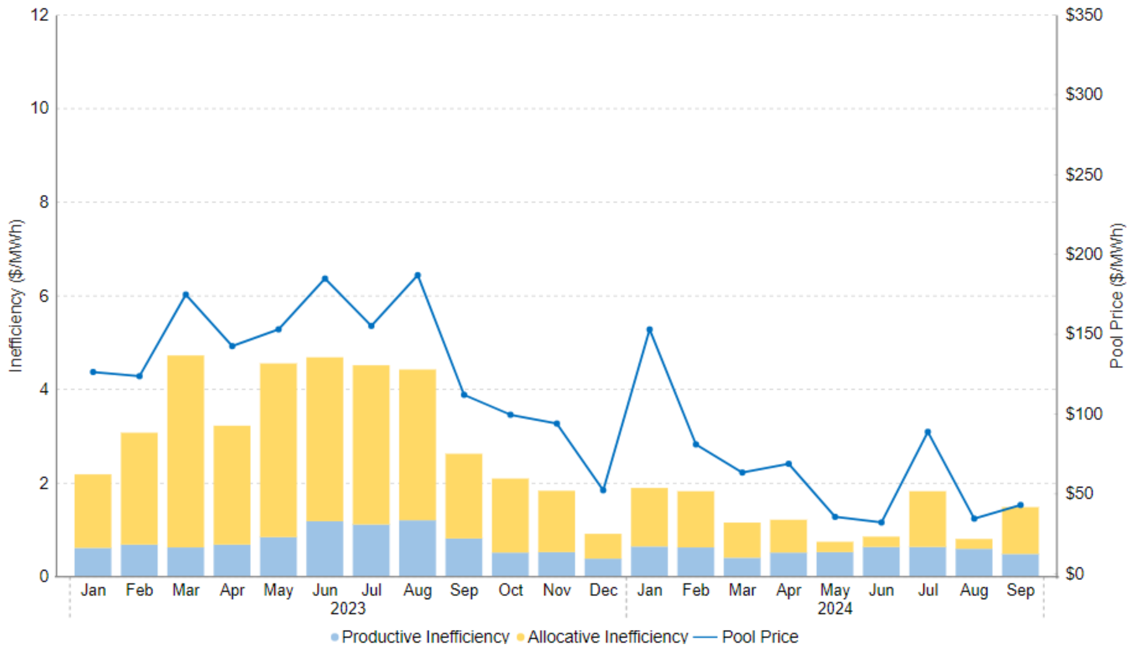


The exercise of market power can lead to short run economic inefficiencies. Productive inefficiencies arise when lower-cost capacity is withheld and replaced by higher-cost generation. Allocative inefficiencies arise when demand is less than it would have been because the exercise of market power increased price.

Figure 20 illustrates average static inefficiencies by month going back to January 2023. In all months of Q3 static inefficiencies fell year-over-year; in August static inefficiencies fell from \$4.42/MWh to \$0.80/MWh, a decline of 82%.

Despite the increase in supply outlined in section 1.1 the opportunity to exercise market power continued to prevail in hours with high demand and low intermittent generation. Consequently, static inefficiencies in Q3 were highest in July at \$1.82/MWh as allocative inefficiencies were increased by the exercise of market power. Nevertheless, static inefficiencies were still 60% lower than in July 2023.

Figure 20: Monthly average static inefficiency (January 2023 to September 2024)



1.4.2 Offer behaviour

Less capacity was offered into the market at higher prices in Q3 relative to Q3 2023. Figure 21 below shows the average amount of capacity offered above $250/MWh by month. In Q3 2023 there was an average of 1,390 MW offered above $250/MWh, but this fell to 720 MW in Q3, a decline of 48% year-over-year.

Figure 22 illustrates the average amount of capacity priced above $250/MWh by month and firm since January 2023. In Q3 both TransAlta and Heartland offered less capacity above $250/MWh compared to Q3 2023. On average, TransAlta priced 635 MW above $250/MWh in Q3 2023, but this fell to 225 MW in Q3. Similarly, the amount of generation capacity offered above $250/MWh by Heartland fell from 455 MW to 185 MW year-over-year.

As discussed in the preceding section, the change in market fundamentals, including the addition of Cascade 1 and 2 and more supply of intermittent generation, has reduced the ability of larger firms to exercise market power. Consequently, less capacity was offered into the merit order at higher prices in Q3.

On average ‘Other’ market participants offered 194 MW of generation capacity into the market above $250/MWh in Q3. This figure includes assets such as Cascade 1 and 2 and HR Milner which were used to exercise market power at certain points in the quarter.

Figure 21: Average amount of capacity priced above $250/MWh by month (January 2020 to September 2024)

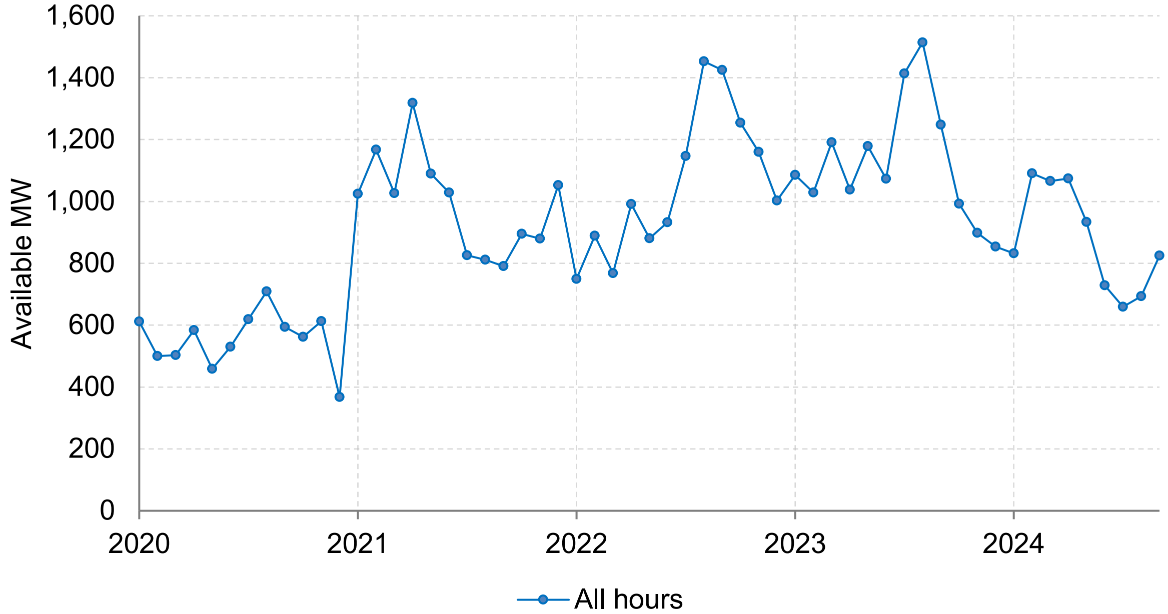
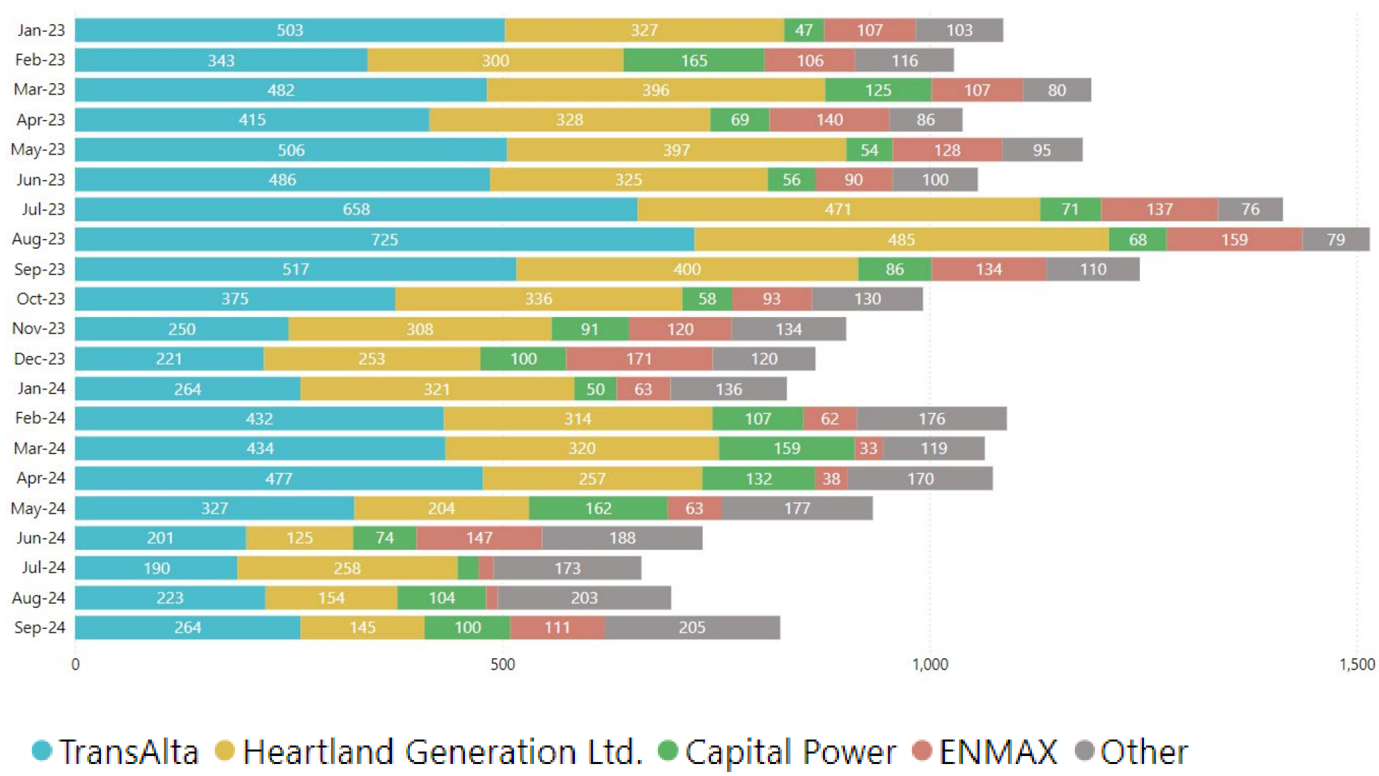


Figure 22: Average amount of capacity priced above $250/MWh by firm and month (January 2023 to September 2024)



1.5 Carbon emission intensity

Carbon emission intensity is the amount of carbon dioxide equivalent emitted for each unit of electricity produced. The MSA has published analysis on the carbon emission intensity of the Alberta electricity grid in its quarterly reports since Q4 2021. The MSA's analysis is 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.[10]

1.5.1 Hourly average emission intensity

The hourly average emission intensity is the volume-weighted average carbon emission intensity of assets supplying the Alberta grid in each hour. Table 9 shows the minimum, mean, and maximum hourly average emission for Q3 over the past seven years. Notably, the maximum hourly average emission intensity for Q3 2024 was lower than the minimum hourly average emission intensity for Q3 2019. Table 10 shows the same summary statistics for the past four quarters, demonstrating recent declines in the hourly average emission intensity.

Table 9: Year-over-year min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2018 Q3	0.55	0.68	0.78
2019 Q3	0.53	0.65	0.74
2020 Q3	0.44	0.59	0.70
2021 Q3	0.43	0.55	0.64
2022 Q3	0.38	0.50	0.58
2023 Q3	0.31	0.45	0.56
2024 Q3	0.25	0.40	0.53

Table 10: Quarter over quarter min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2024 Q4	0.30	0.43	0.57
2024 Q1	0.27	0.45	0.58
2024 Q2	0.26	0.39	0.56
2024 Q3	0.25	0.40	0.53

Figure 23 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q3 over the past seven years. Figure 24 illustrates the distribution of the hourly average carbon emission intensity over the past four quarters. The conversion of coal-fired generation to natural gas, in addition to increased intermittent generation, has driven a decline in carbon emission

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

intensity. This decline in carbon intensity over time is demonstrated by the leftward shift of hourly average carbon intensity distributions as shown in Figure 23.

Figure 23: The distribution of average carbon emission intensities in Q3 (2018 to 2024)

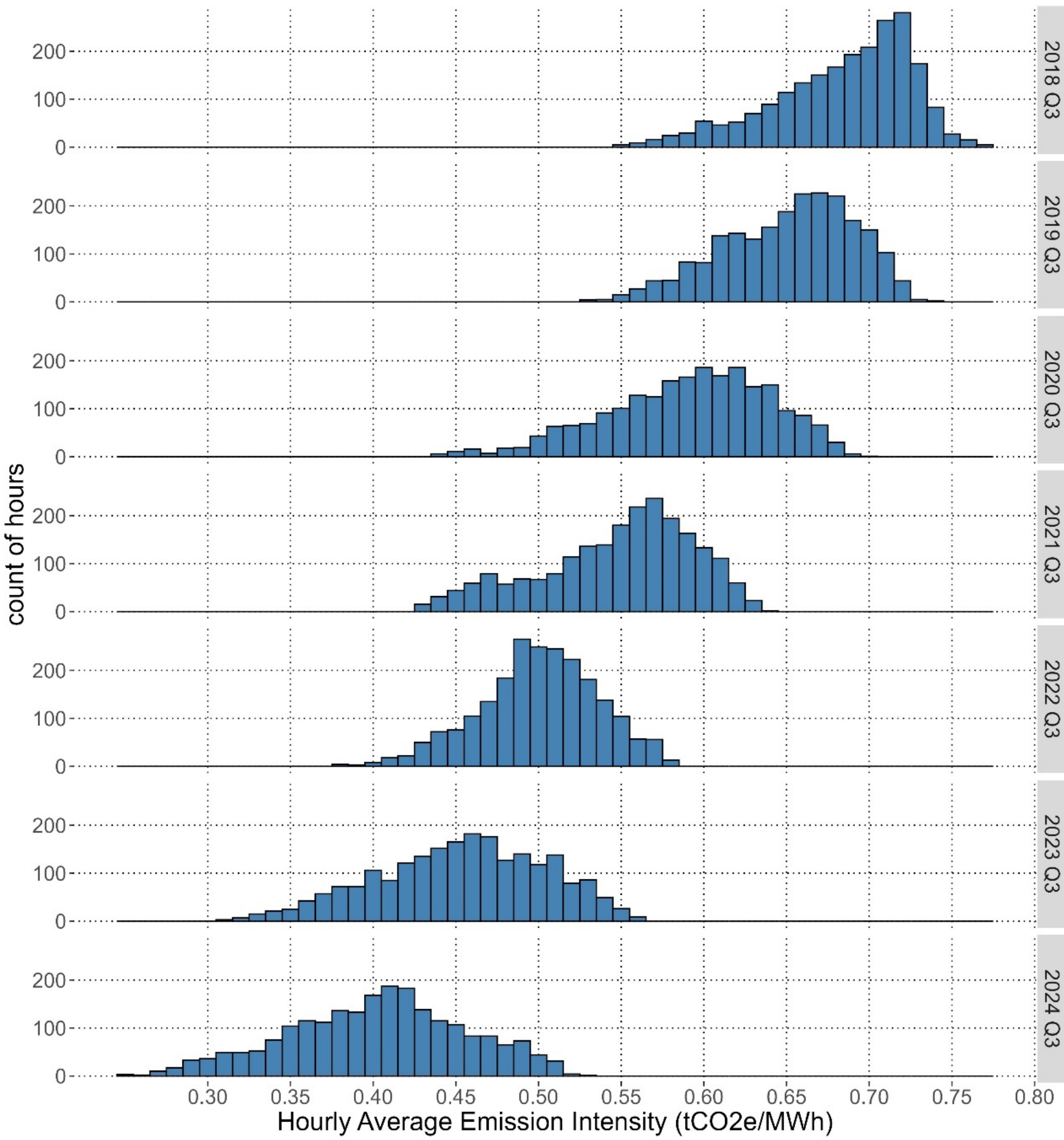
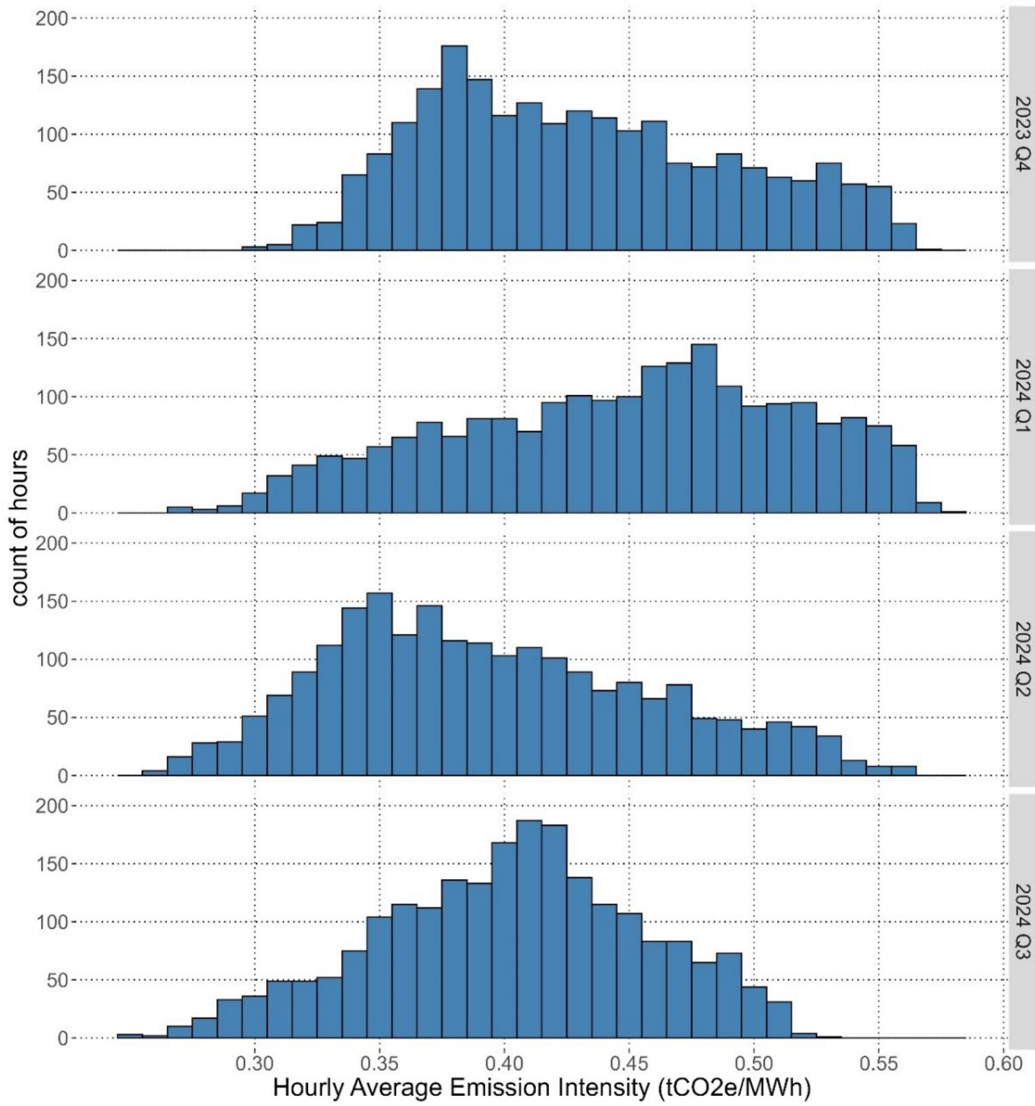
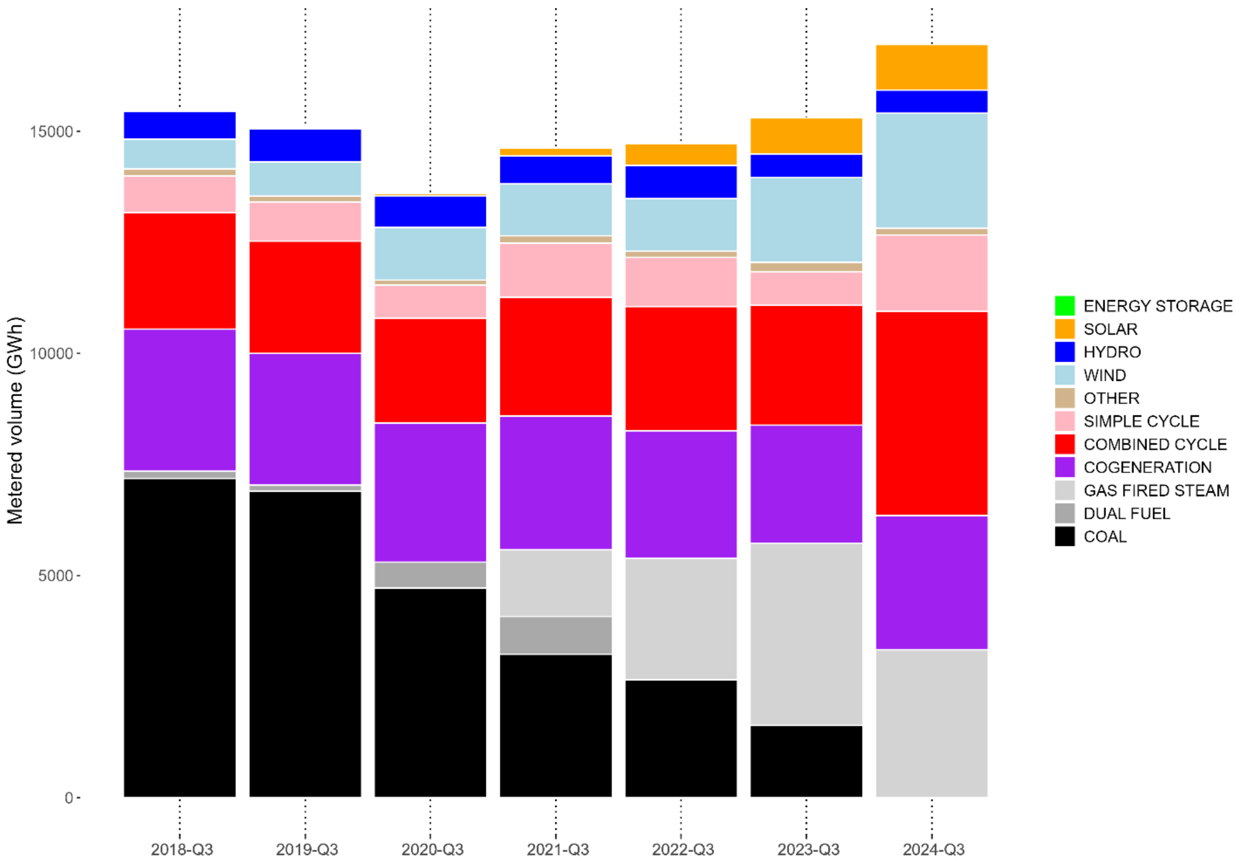


Figure 24: The distribution of average carbon emission intensities in the past four quarters



The leftward shifts of the distributions in Figure 23 can be traced to Figure 25, which shows the net-to-grid generation volumes by fuel type. Since 2019, there has been a material decline in the volume of coal-fired generation due to retirements and coal-to-gas conversions. In addition, the continuous increase in intermittent generation driven by growing capacity has also contributed to the displacement of coal-fired generation. Increased generation from Cascade 1 and 2, and Genesee Repowered 1 and 2, have also put downwards pressure on average carbon intensity more recently.

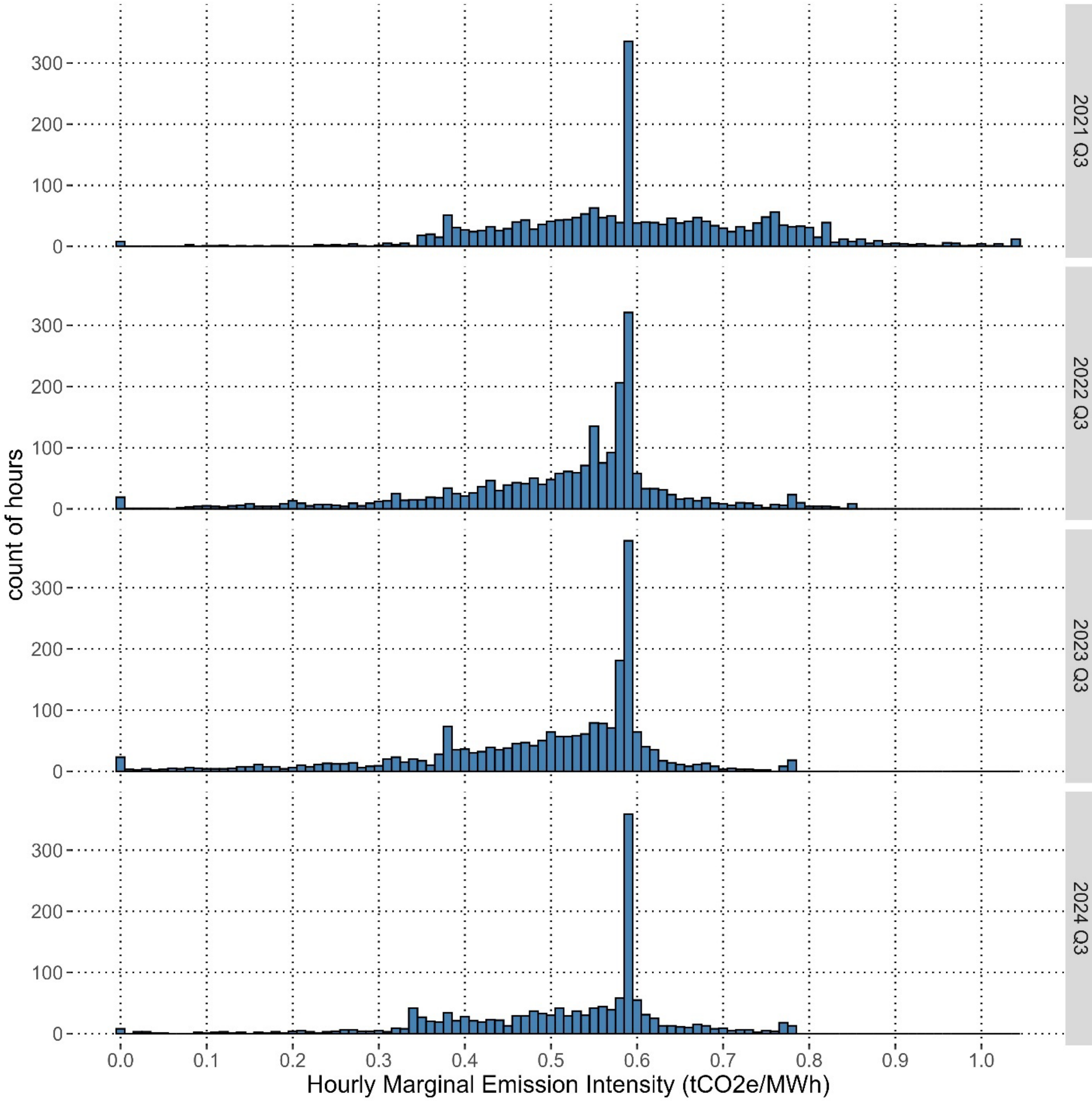
Figure 25: Quarterly total net-to-grid generation volumes by fuel type for Q3 (2018 to 2024)



1.5.2 Hourly marginal emission intensity

The hourly marginal emission intensity of the grid is the carbon emission intensity of the asset setting the 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 26 shows the distribution of the hourly marginal emission intensity of the grid in Q3 for the past four years. Gas-fired steam assets were setting the price quite often, which was a factor in the spike observed around 0.59 tCO2e/MWh from Q3 2021 onwards.

Figure 26: The distribution of marginal carbon emission intensities in Q3 (2021 to 2024)



2 THE POWER SYSTEM

2.1 Trends in transmission congestion

Transmission constraints can cause generation to be curtailed. When this occurs, the AESO directs constrained generators to reduce their output to manage the constraint; this is constrained down generation. In this section, the MSA examines trends in intermittent constrained down generation.

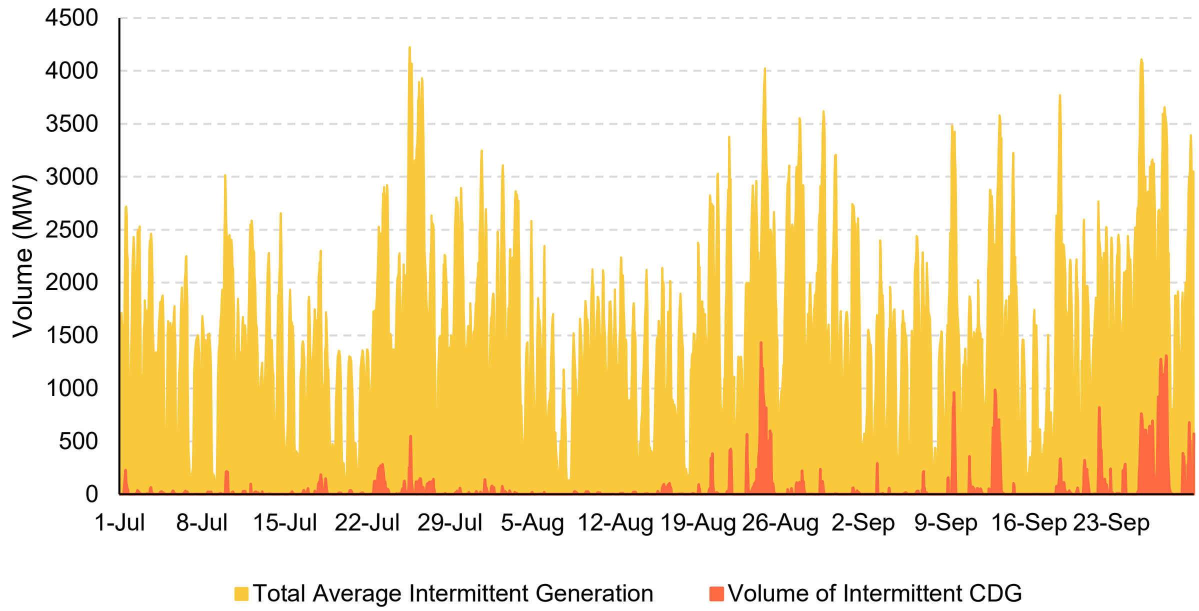
The frequency and significance of intermittent constrained down generation directives increased from Q3 2023 to Q3.[11] The MSA estimates that intermittent constrained down generation volumes were 44 GWh in Q3 2023 and 125 GWh in Q3. This is more than a doubling of volumes year-over-year. Quarter-over-quarter, the intermittent constrained down generation volumes decreased by 89 GWh. The maximum hourly average volume of intermittent generation constrained down in Q3 was 1,434 MW, almost triple the maximum of 498 MW in Q3 2023 (Figure 29 to Figure 31). The Q3 maximum hourly average volume of intermittent constrained was lower than the previous quarters maximum value of 1,665 MWh (Figure 30).

The increased constrained volumes in Q3 are likely due to increased intermittent capacity and high intermittent generation, as detailed in Section 1.1 and demonstrated in Figure 3. Generally, higher intermittent constrained down volumes align with periods of high intermittent generation or supply surplus events when supply is often high (Figure 27).

There were over 257 shift log events for constrained down generation in Q3. Increased constrained down generation volumes may also be due to persistent or frequent congestion on certain transmission lines and may affect one or more generation assets. One example of a frequently constrained transmission line is 610L, which is the subject of the Vauxhall Area Transmission Development. However, this quarter saw a wide variety of constraints and zones.

[11] The AESO's ETS Estimated Cost of Constraint Report calculate TCR volumes using a different methodology than the MSA's estimate of constrained down generation. The MSA's Quarterly Report for Q2 2023 discusses how the MSA calculates the constrained down volumes.

Figure 27: Average hourly intermittent generation and constrained down volumes for Q3



The increase in intermittent constrained down volume from Q3 2023 to Q3 occurred at a higher rate than the installation of intermittent generation capacity. While total installed intermittent capacity increased by 36%, average hourly constrained down volumes, expressed as a percent of installed intermittent capacity, increased from 0.39% in Q3 2023 to 0.81% in Q3 (Figure 28).

Figure 28: Volume of intermittent CDG compared to total potential intermittent generation in Q3

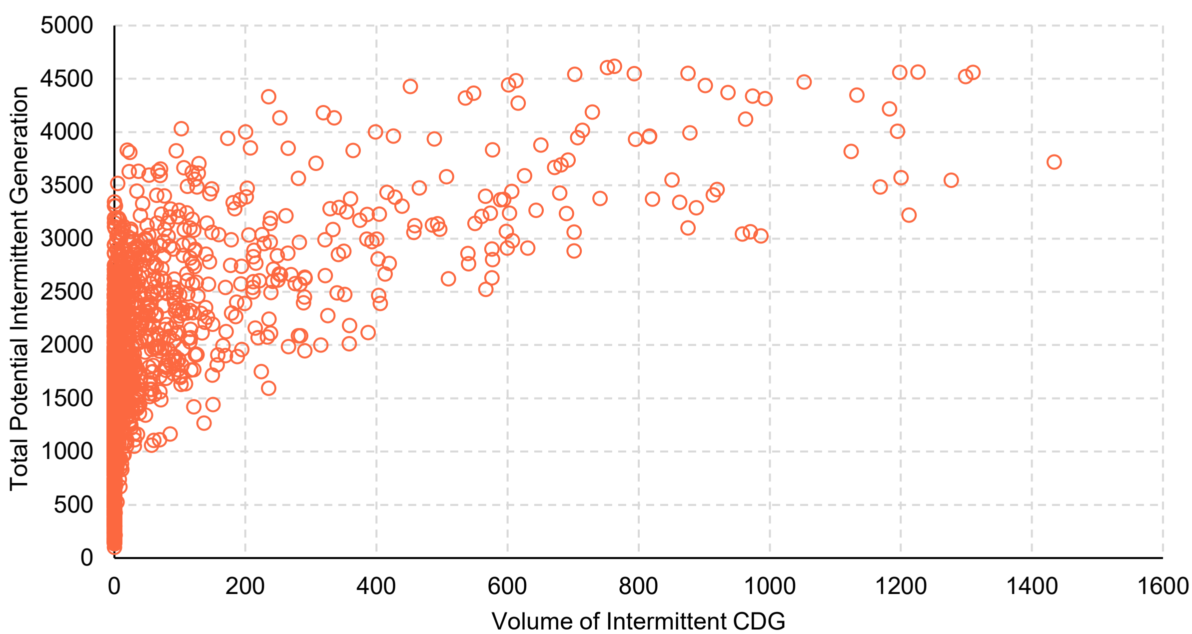


Figure 29: Maximum hourly transmission constrained intermittent generation (Q3 2023)

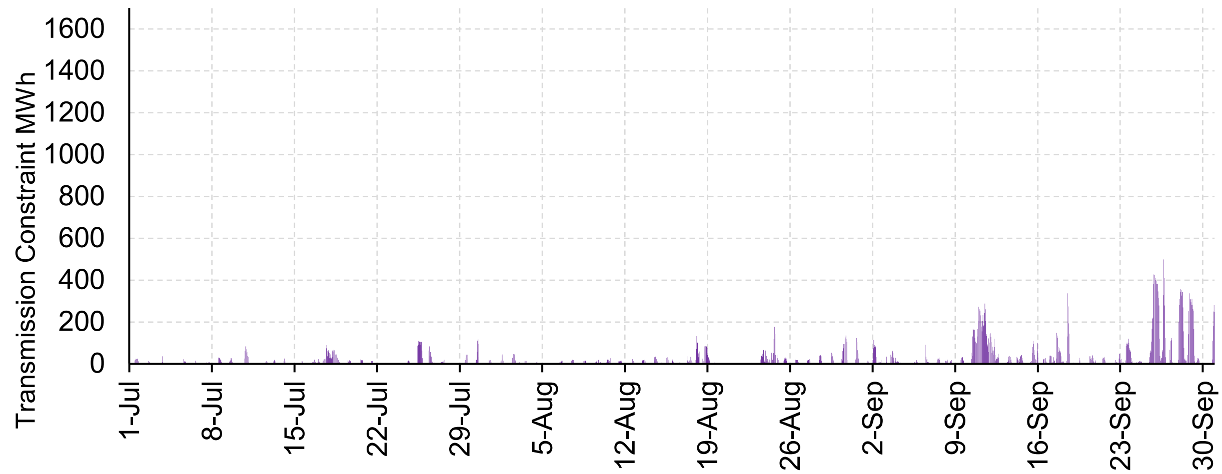


Figure 30: Maximum hourly transmission constrained intermittent generation (Q2 2024)

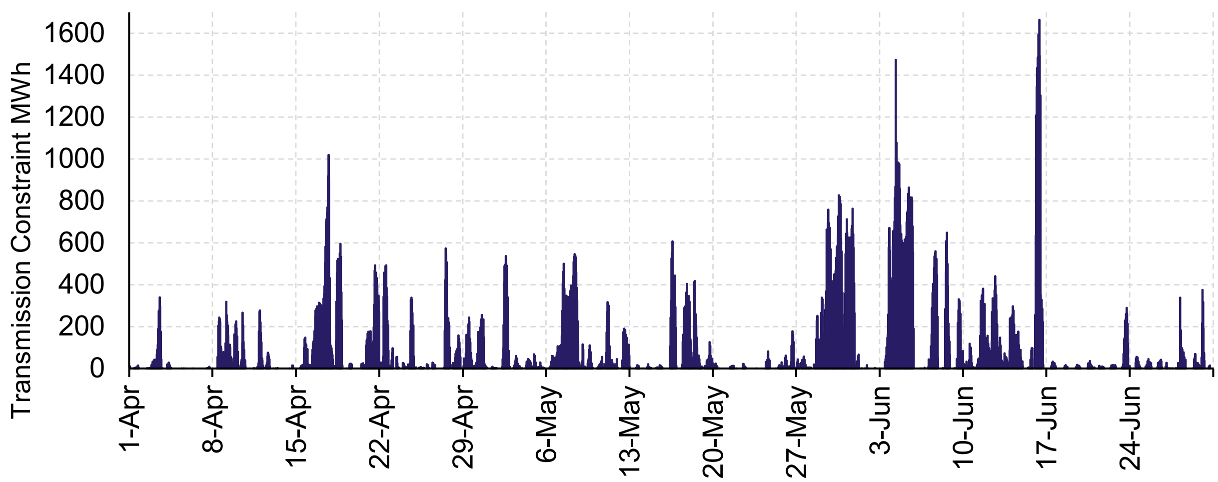


Figure 31: Maximum hourly transmission constrained intermittent generation (Q3 2024)

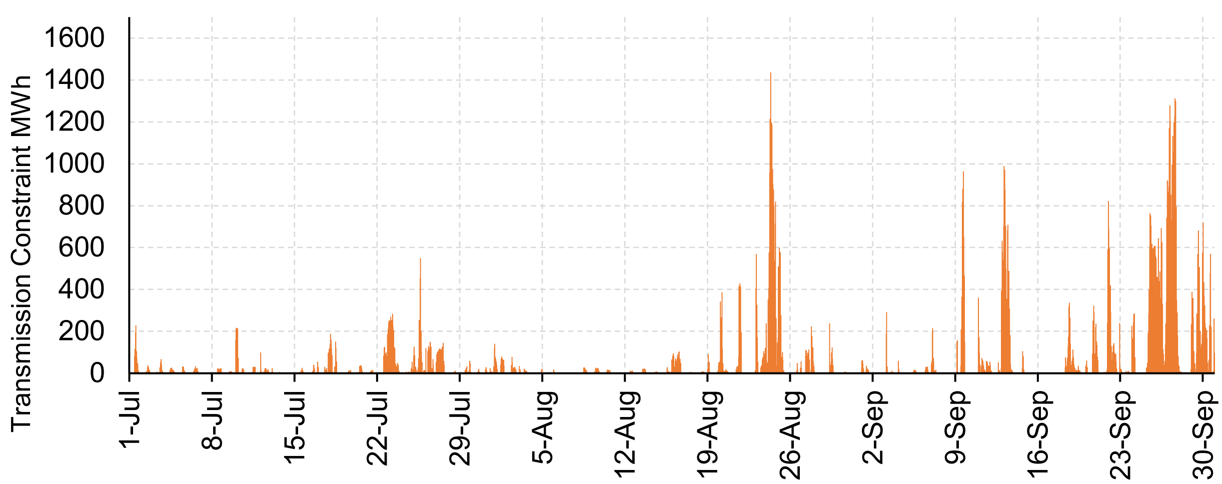
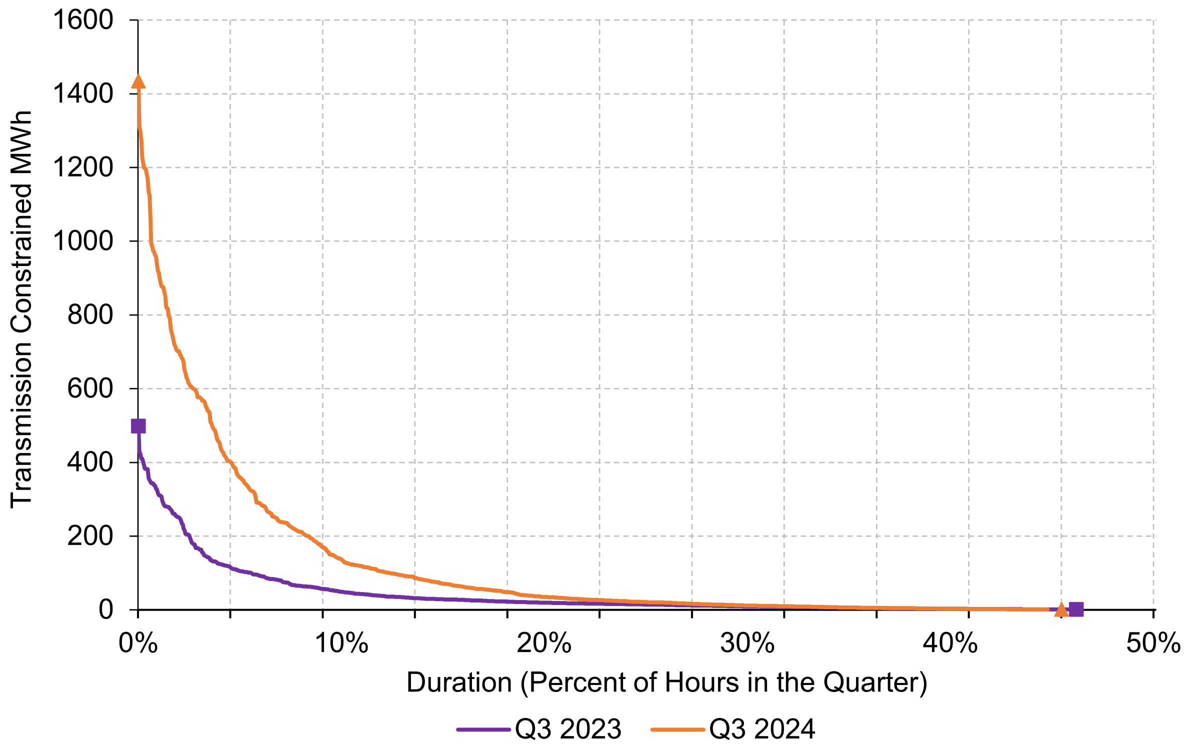


Figure 32 illustrates duration curves of constrained intermittent generation year-over-year. The length of the tails to the right of the duration curves show that the frequency of intermittent constrained down events decreased. There were 986 hours of intermittent constrained down generation greater than 1 MWh in Q3. This is equivalent to just over 41 days, or 45% of Q3. In contrast, Q3 2023 experienced 1,020 hours of intermittent constrained down generation greater than 1 MWh, or over 43 days or 46% of Q3 2023.

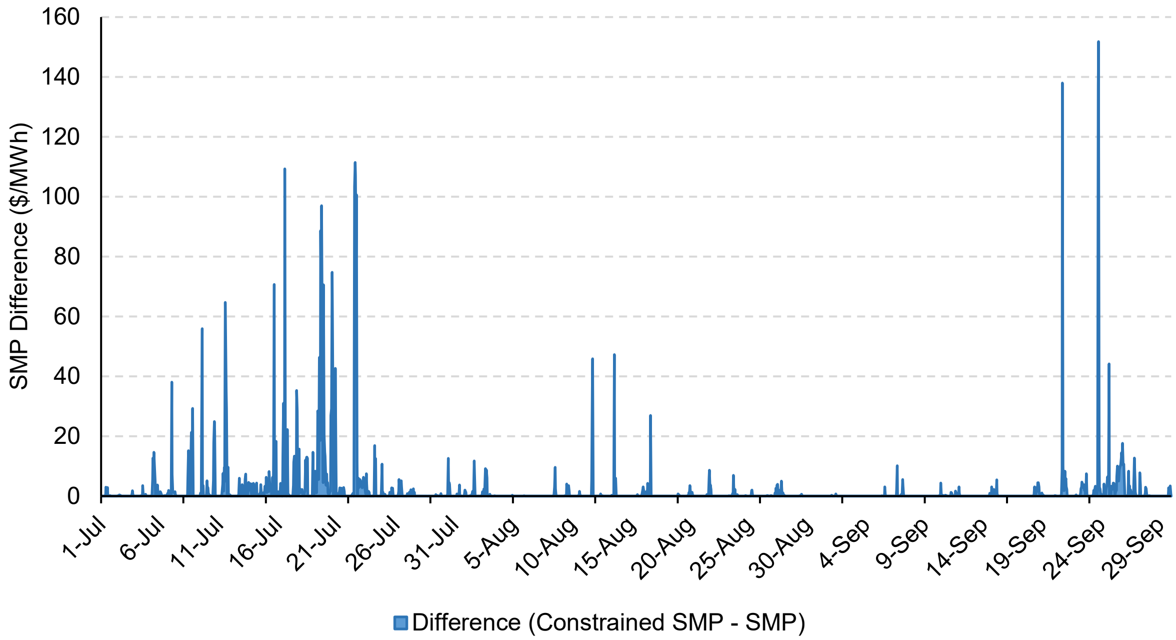
Figure 32: Duration of intermittent constrained volume (Q3 2023 and Q3)



Transmission constraints had frequent fluctuations throughout all months of Q3, however September experienced the most volume of congestion and August experienced the highest peak. The intermittent constrained down volume in the month of September accounted for 63% of all Q3 volumes. In 49% of September hours there was at least 1 MWh of intermittent constrained down volume.

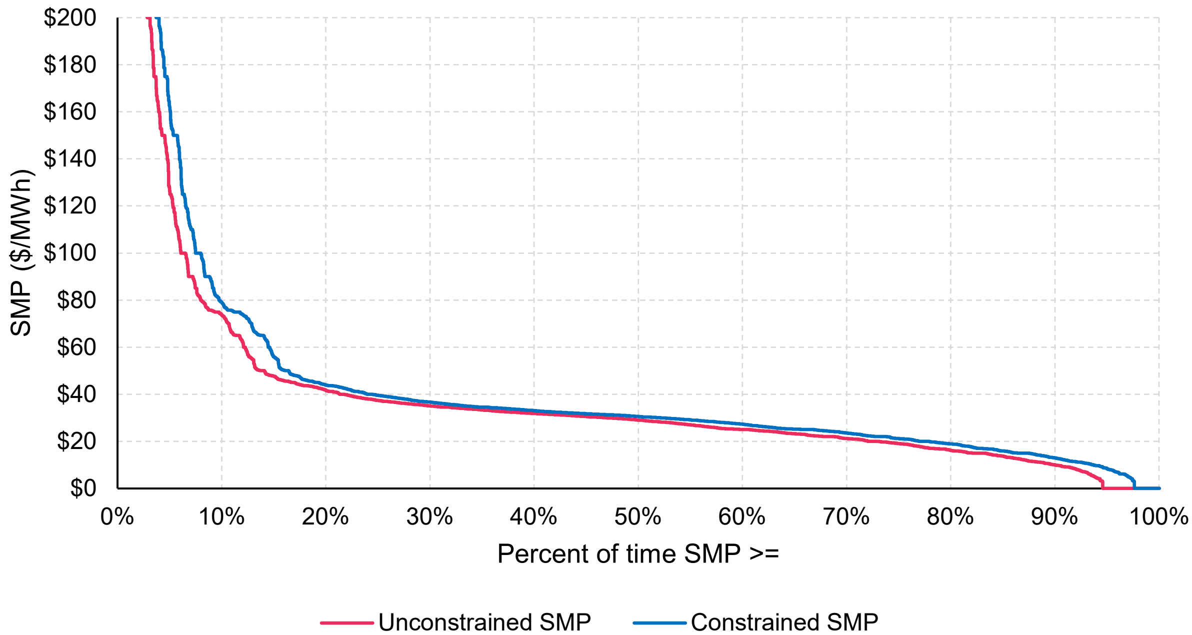
The constrained and unconstrained SMP differed by $1/MWh or more in 18% of hours in Q3 (Figure 33). In comparison, Q3 2023 experienced 17% of hours with a variance of $1/MWh or more in the constrained SMP and unconstrained SMP, and Q2 2024 experienced the difference in 27% of hours. The largest difference between constrained SMP and SMP in Q3 was $152/MWh, which occurred in HE20 of September 23. Despite the frequency and significance of the intermittent constrained down generation in Q3, the largest difference in unconstrained and constrained price was higher in Q3 2023 at $399/MWh. The largest difference in Q2 2024 occurred on June 4 and reached $637/MWh, over four times the Q3 peak. The largest difference since 2023 remains on October 19, 2023, at $866/MWh.

Figure 33: Difference of Constrained SMP and SMP in Q3



The periods that experience high volumes of intermittent constraints often occur when generation from intermittent resources is high. Given the offer behaviour of these resources, when intermittent generation is higher, SMP is lower as higher priced generation is displaced. Therefore, despite the high amount of constrained volumes in Q3, there was often only a small difference between the unconstrained SMP and the constrained SMP (Figure 34). This occurs because when prices are low the supply curve is normally relatively flat, meaning that large changes in quantity may have a relatively small impact on prices.

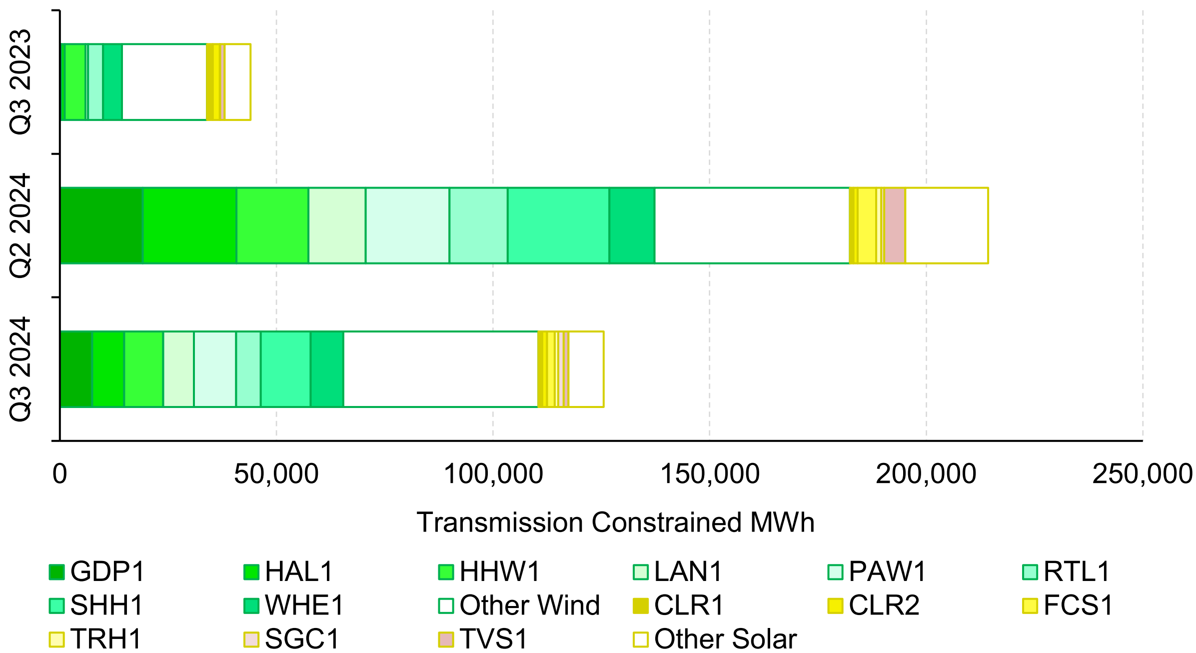
Figure 34: Duration of SMP and constrained SMP for Q3



Transmission capability varies throughout the province, and certain regions may experience more congestion than others, often leading to local constraints (Figure 35). Often, wind and solar assets are not constrained uniformly throughout the province. In Q3, the eight most constrained wind assets accounted for 59% of the total constrained down volume but only 25% of total installed wind generation. Sharp Hill Wind, Paintearth Wind Project, and Hand Hills were the most constrained wind assets in Q3. These 3 assets represent 12% of Alberta's installed wind capacity, however they accounted for approximately 27% of the wind constrained volume in Q3.

Fox Coulee Solar (80 MW) was the most-constrained solar asset in Q3, with a total of 1,768 MWh constrained. The asset was constrained due to a variety of constraints over the quarter, along with several other assets. The following five most constrained solar assets have an aggregate maximum capability of 653 MW (188 MW excluding Travers) and were constrained by 5,211 MWh (4,077 MWh excluding Travers) in Q3. The top 6 constrained solar assets account for 44% of the maximum capability of the market and accounted for 46% of solar constrained volumes in Q3. Although this appears to be a more even allocation of capability and congestion, the inclusion of Travers, which has a lower constrained volume and high maximum capability, misrepresents the distribution. Excluding Travers capability and congestion, the top constrained assets account for 22% of the maximum capability of the market and accounted for 42% of solar constrained volumes in Q3. The uneven distribution of congestion volumes to intermittent assets continues within Alberta.

Figure 35: Wind and solar transmission constrained MWh by asset (Q3 2023, Q2 2024 and Q3)

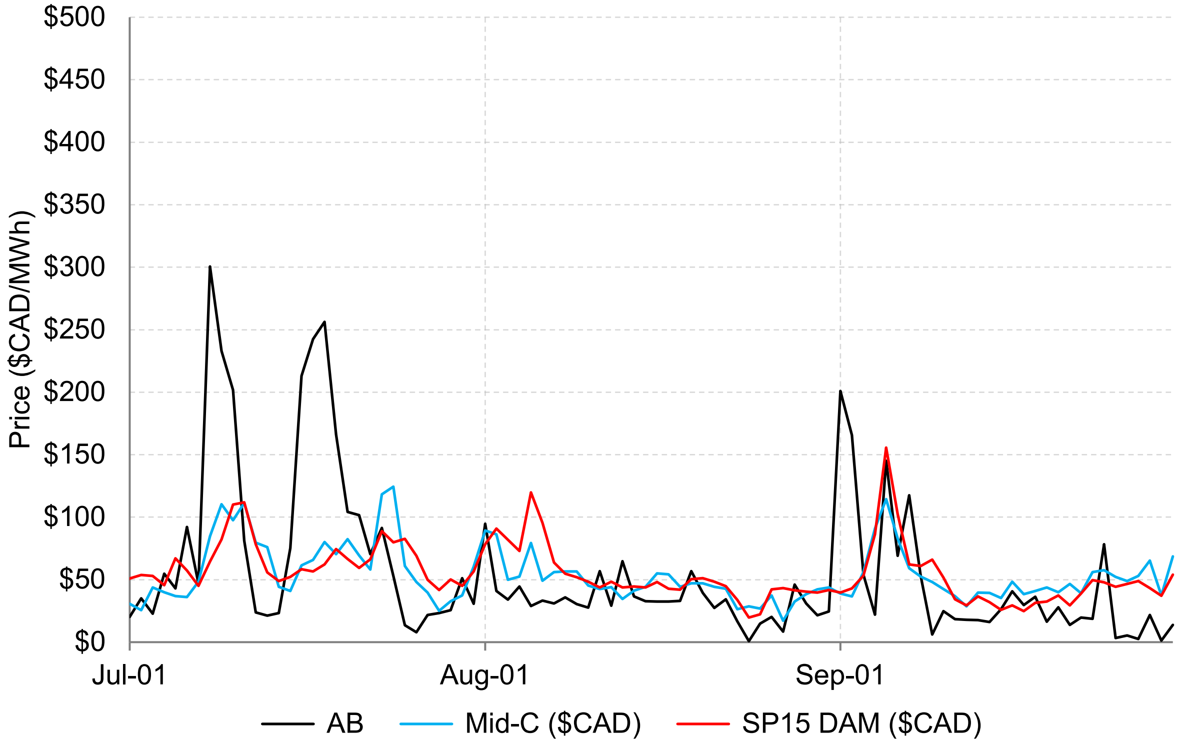


2.2 Imports and exports

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. The AESO manages the BC intertie and MATL as one shared cutplane (BC/MATL) because any trip on the BC intertie results in a direct transfer trip to MATL. These interties indirectly link Alberta's electricity market to markets in Mid-Columbia (Mid-C) and California.

Figure 36 provides the daily average power price in Alberta, Mid-C, and California (SP-15) over Q3 (shown in Canadian currency). Alberta prices averaged higher than Mid-C and SP-15 over July due to periods of price volatility early and mid-month. This period of volatility was partly driven by transmission outages which derated the BC/MATL intertie, as discussed in section 1.2. Over August and September, Alberta prices were lower than Mid-C and SP-15 on average, resulting in more exports over these months.

Figure 36: Daily average power prices in Alberta, Mid-C, and SP15 in California (Q3)



Alberta was a net exporter of electricity over the quarter, largely driven by export volumes to BC. In Q3, the scheduled net interchange on the BC intertie averaged 249 MW of exports. The highest monthly volume occurred over August which averaged 362 MW of exports (Table 11), or 538 MW during off peak hours and 275 MW during on peak hours. During Q3 2023, the BC scheduled net interchange averaged 20 MW of exports, with August 2023 averaging 3 MW of imports. The main drivers of the increased export volumes year-over-year are lower pool prices in Alberta and reduced hydro supply in BC and in Mid-C.

The scheduled net interchange on MATL averaged 47 MW of exports, compared to 83 MW of imports in Q3 2023. This increase in exports was driven by lower pool prices in Alberta and comparatively higher Mid-C prices over the course of the quarter (Table 11).

On the SK intertie the scheduled net interchange averaged 17 MW of imports, compared to 42 MW of imports in Q3 2023. Lower pool prices in Alberta compared to Q3 2023 was a driver of lower imports from Saskatchewan (Table 11).

Table 11: Average net import (+ve) and export (-ve) volumes for Q3 2023 and Q3 2024

	2023				2024			
	BC	**MATL**	**SK**	**Total**	**BC**	**MATL**	**SK**	**Total**
July	-38	83	45	90	-167	-39	22	-185
August	3	71	30	104	-362	-64	9	-418
September	-25	97	51	124	-215	-37	19	-212
Q3	**-20**	**83**	**42**	**106**	**-249**	**-47**	**17**	**-279**

Figure 37 shows the daily average schedule of intertie volumes for BC/MATL, with intertie capability and the price differential between Alberta and Mid-C also illustrated. Over Q3, BC/MATL import capability averaged 518 MW and export capability averaged 855 MW. As shown, there were several periods of intertie outages/derates on BC/MATL:

- Between July 8 and 10, import capability was derated due to a planned outage for 2L294 (BC).

- Beginning on July 16 import capability was derated due to a planned outage for 5L92 (BC) until July 18. During July 17 HE 22, the BC intertie tripped out of service due to lighting in the area, causing a MATL transfer trip, leading to an islanding event until July 18 HE 02.

- During July 22 HE 17, MATL experienced a forced outage due to weather, resulting in an outage on the BC intertie and an islanding event over the hour.

- Between August 20 and 24, import capability was derated due to a planned outage on 5L92 (BC).

- Between September 23 and October 3 Alberta was islanded due to a planned outages on the BC intertie and MATL.

Figure 37: Daily average import (+ve) and export (-ve) scheduled volumes on BC/MATL, and the average price differential between Alberta and Mid-C (Q3)

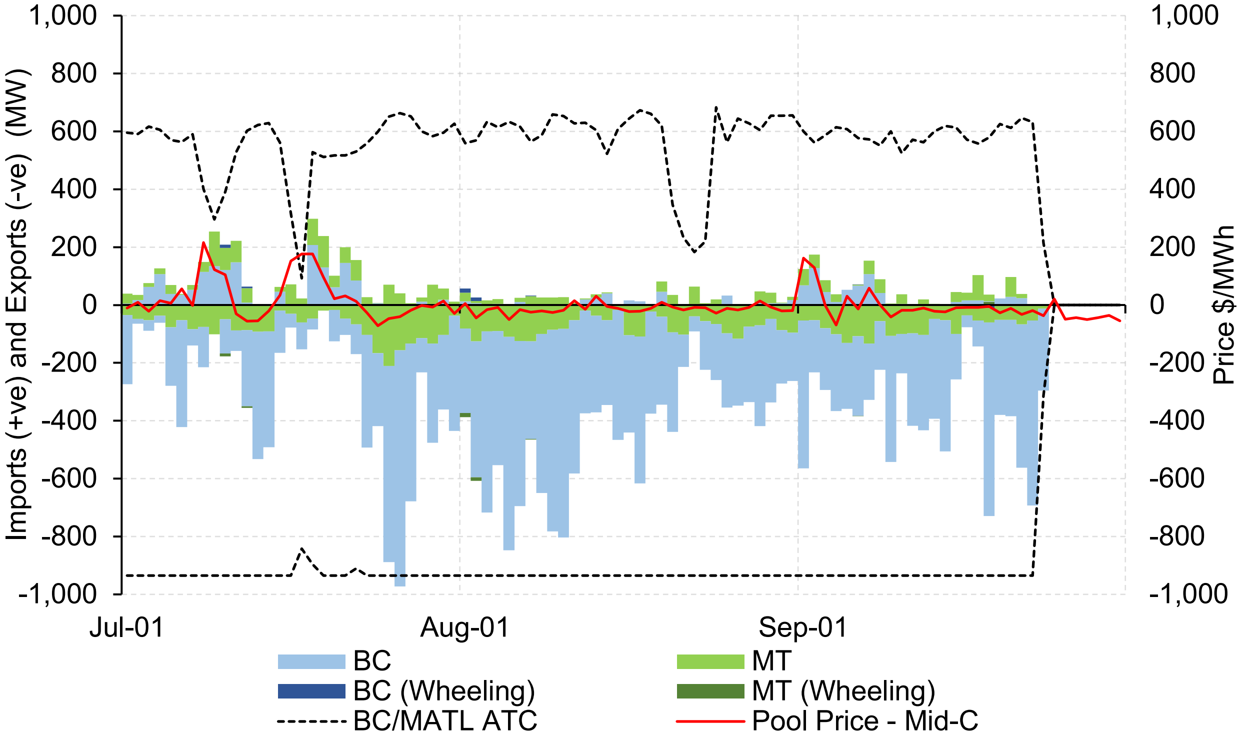


Figure 38 and Figure 39 show the BC/MATL scheduled volumes, price differential between Alberta and Mid-C, and import capability during periods of planned outages in early and mid July.

On July 8 and 9 high demand and low wind generation meant pool prices were elevated but the supply of imports on BC/MATL was restricted to around 250 MW due to a planned outage on 2L294 (Figure 38).

On July 16 and 17 high demand and low wind generation again increased pool prices however the supply of imports on BC/MATL was restricted to under 50 MW because of a planned outage on 5L92 (Figure 39). Lower intertie capability can put upward pressure on pool prices as the supply of $0/MWh imports is restricted.

Figure 38: Hourly import (+ve) and export (-ve) scheduled volumes on BC/MATL, and the average price differential between Alberta and Mid-C (July 8 to 10)

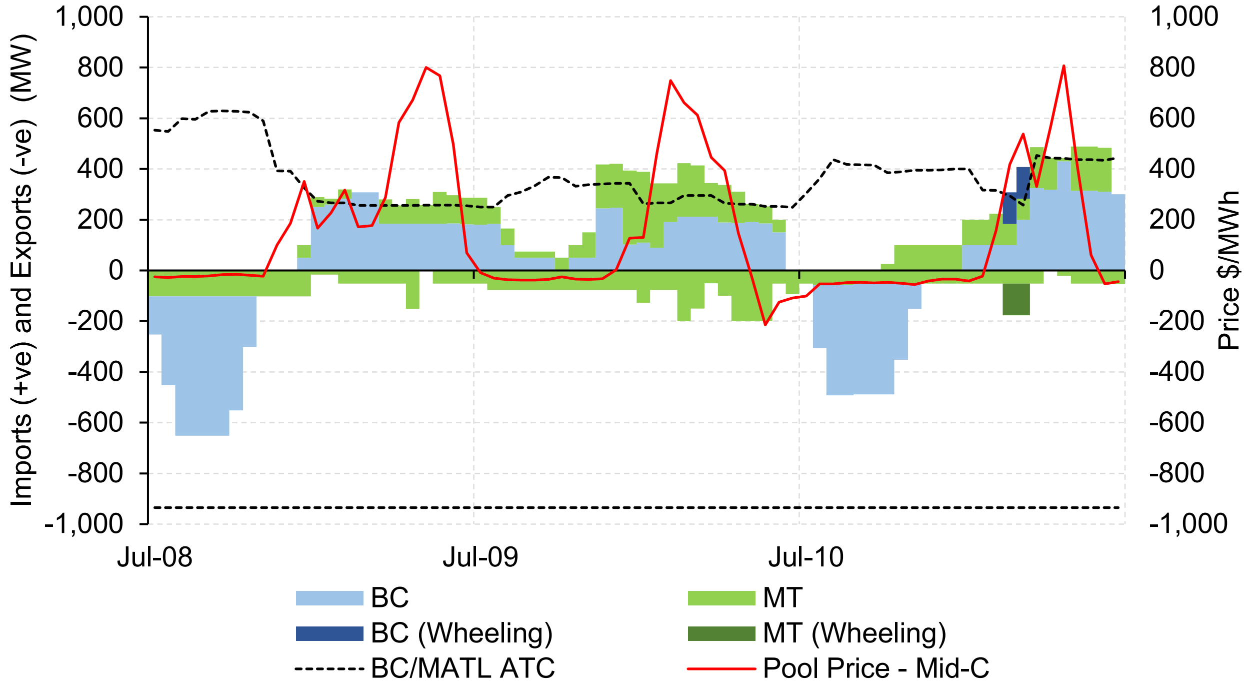
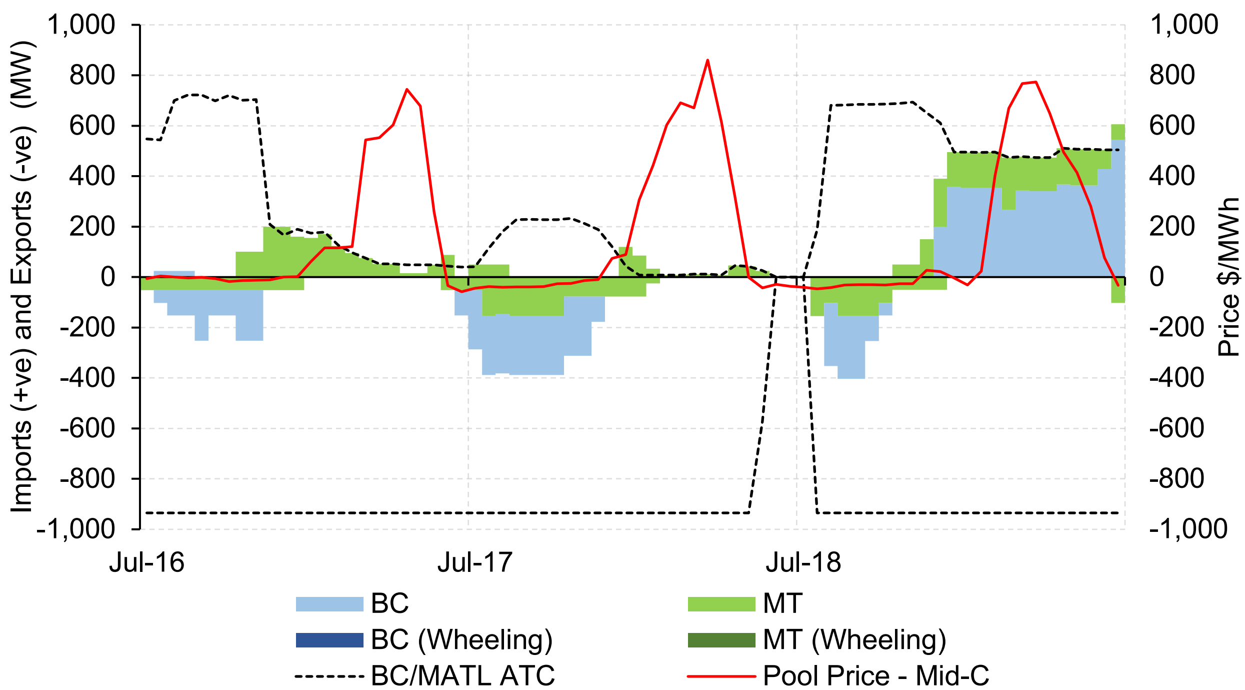


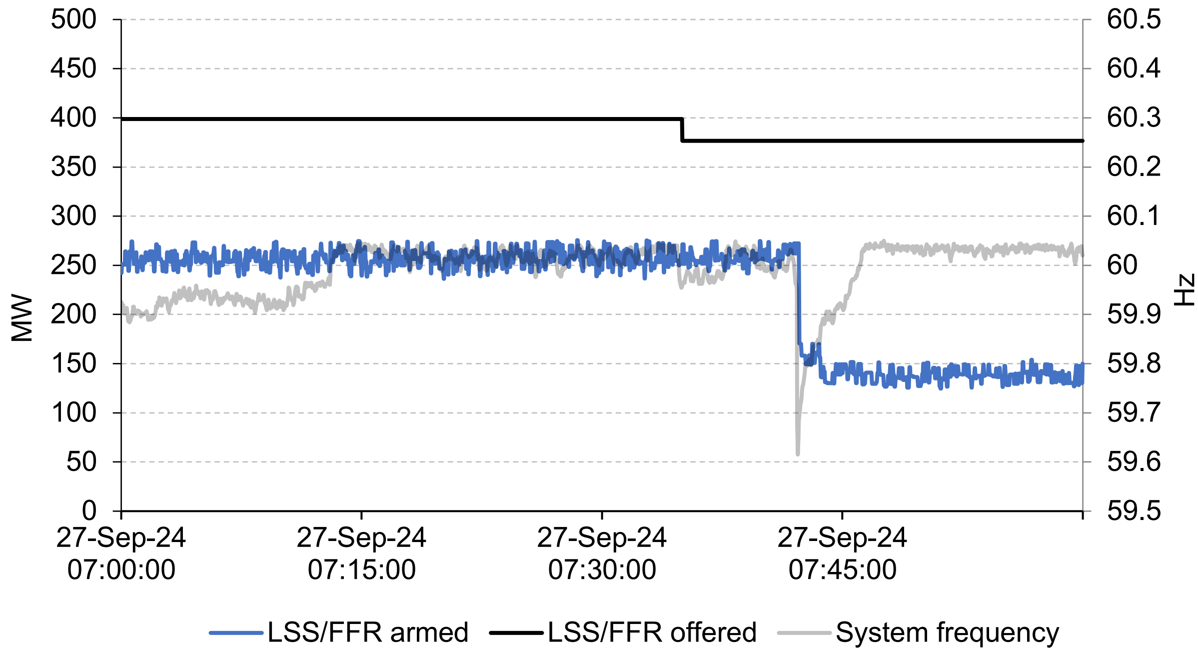
Figure 39: Hourly import (+ve) and export (-ve) scheduled volumes on BC/MATL, and the average price differential between Alberta and Mid-C (July 16 to 18)



Beginning on September 23, Alberta was islanded from the Western Interconnection as the BC intertie and MATL went offline for planned maintenance. The AESO armed Load Shed Service (LSS)[12] and Fast Frequency Response (FFR)[13] in order to maintain the Most Severe Single Contingency (MSSC) limit of 466 MW, averaging 220 MW of armed LSS/FFR over the duration of time Alberta was islanded.

The armed LSS/FFR was tripped on September 27 and 28 to help maintain system frequency. On September 27 around 100 MW of armed LSS/FFR tripped in response to the trip at Cascade 1 just before 07:45 (Figure 40). On September 28 around 210 MW of armed LSS/FFR tripped in response to the trip at Cascade 1 just before 20:00 (Figure 41).

Figure 40: LSS/FFR trip event (September 27, 2024)



[12] LSS is a reliability product developed to mitigate the impact of under frequency excursions and is contracted between the AESO and load providers who agree to instantaneously shed consumption in the case of a sudden loss of imports or internal generation. Load Shed Service for imports (LSSi) refers to the specific case of using LSS for the purposes of increasing import capability.

[13] FFR is a reliability product developed to mitigate the impact of under frequency excursions caused by the sudden loss of imports or internal generation and is contracted between the AESO and eligible providers.

Figure 41: LSS/FFR trip event (September 28, 2024)

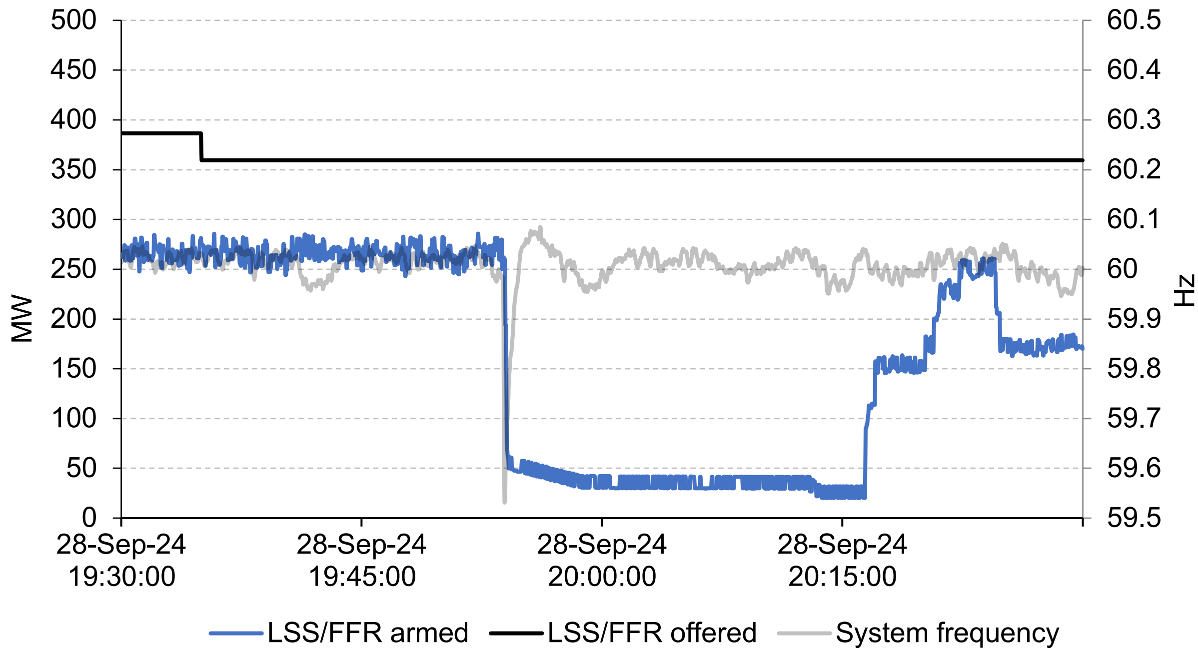
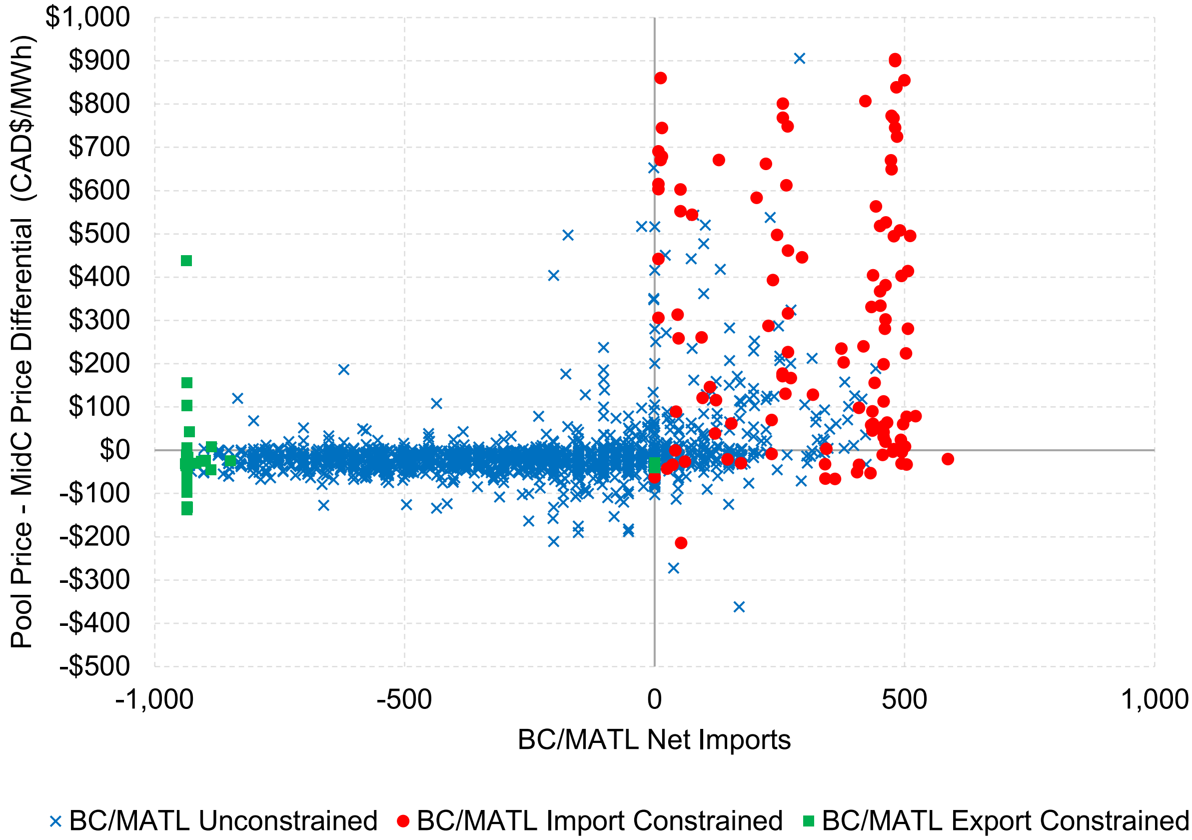


Figure 42 shows a scatterplot of the price differential between Alberta and Mid-C against the net scheduled flows on BC/MATL for each hour over the quarter. Economic flows are generally in the top right and bottom left segments based on the realized price differential (without consideration of transmission costs or other factors).

In certain hours the net import offers or schedule volumes on BC/MATL were at or above import capability, meaning that BC/MATL was import constrained (shown in red). Import constrained observations below the 400 MW range are generally associated with BC/MATL derate/outage periods. BC/MATL imports were constrained for 115 hours in Q3 or 5% of the time. While import constrained, the price differential between Alberta and Mid-C averaged $293/MWh and import capability averaged 335 MW.

There were also hours where net export bids or scheduled volumes were at or above export capability, meaning that BC/MATL was export constrained (shown in green). Constrained values at 0 MW are associated with the BC/MATL outage during the July 17 and 18 islanding event. BC/MATL exports were constrained for 226 hours or 10% of the time in Q2. While export constrained, the differential between Alberta and Mid-C averaged -$25/MWh.

Figure 42: Alberta and Mid-C price differential and net BC/MATL flows (Q3)



For a few hours in Q3, heavy scheduled volumes occurred despite prices settling in the opposite direction. For example, on September 18 in HE02, net exports on BC/MATL were 936 MW even though the pool price in Alberta was $438/MWh higher than prices in Mid-C.

Figure 43 shows import volumes in the quarter by the point of receipt (POR) and export volumes by the point of delivery (POD).[14] The Balancing Authority regions directly connected with Alberta have a high share of import and export flows.

For imports on the BC intertie, approximately 68% originated from BC, 28% from the US Northwest, and 4% from California. For exports on the BC intertie, 98% was delivered to BC, 1% to the US Northwest, and 1% to California

For imports through MATL, 73% originated from the US Northwest, 25% from California, 1% from BC, and 1% from US Central. For exports on MATL 96% was delivered to the US Northwest, 3% to BC, and 1% to California.

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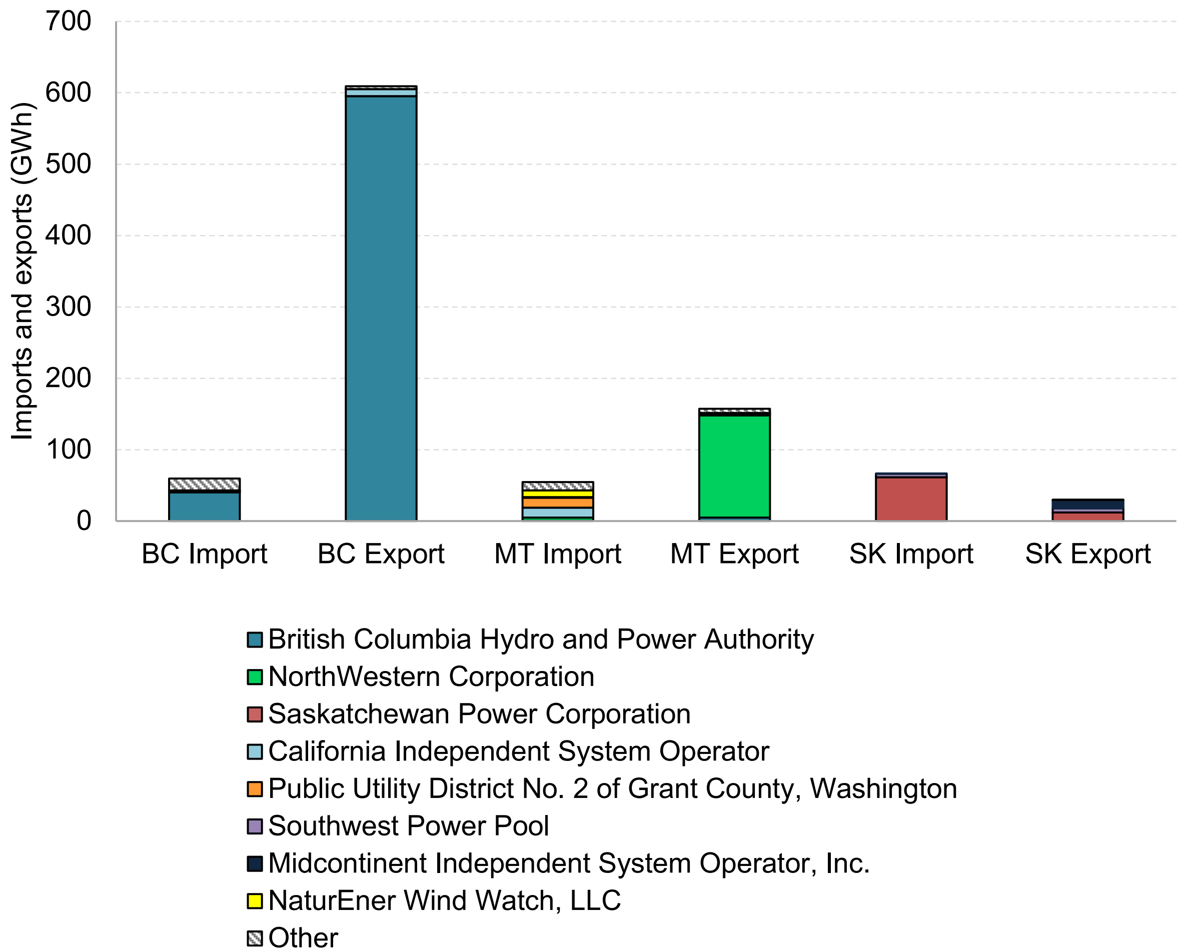
[14] The POR for imports is the point on the electric system where electricity was received from. The POD for exports is the point on the electric system where electricity was delivered to.

For imports through the SK intertie, 92% originated from Saskatchewan and 8% from Southwest Power Pool. For exports through the SK intertie, 40% was delivered to Saskatchewan, 39% to Midcontinent Independent System Operator, 19% to Southwest Power Pool, and 2% to Ontario.

Figure 43: Interchange point of receipt (imports) and point of delivery (exports) for interchange volumes by Balancing Authority (Q3)[15]



[15] This includes the highest eight Balancing Authorities by volume. Wheeled volumes are not included in the figure, these volumes represent 1,100 MWh BC to Montana and 250 MWh from Montana to BC.

3 OPERATING RESERVE MARKETS

AESO system controllers call upon three types of operating reserve (OR) to address unexpected imbalances or lagged responses between supply and demand: regulating reserve (RR), spinning reserve (SR), and supplemental reserve (SUP). Regulating reserve provides an instantaneous response to an imbalance of supply and demand. Spinning reserve is synchronized to the grid and provides capacity that the system controller can direct quickly when there is a sudden drop in supply. Supplemental reserve is not required to be synchronized but must be able to respond quickly if directed by the system controller. The AESO buys operating reserves through day-ahead auctions.

3.1 Received prices

The received prices for operating reserve are determined by indexing equilibrium prices established during the OR auctions to pool price. Figure 44 illustrates monthly average received prices for active OR products and pool price. Quarter-over-quarter, the average received price for regulating reserve increased by $13/MWh, while spinning and supplemental reserves increased by $26/MWh and $18/MWh (Table 12). The increases can be attributed to higher received prices in July.

Figure 44: Average received price for active regulating, spinning, and supplemental reserves (January 2023 to September 2024)

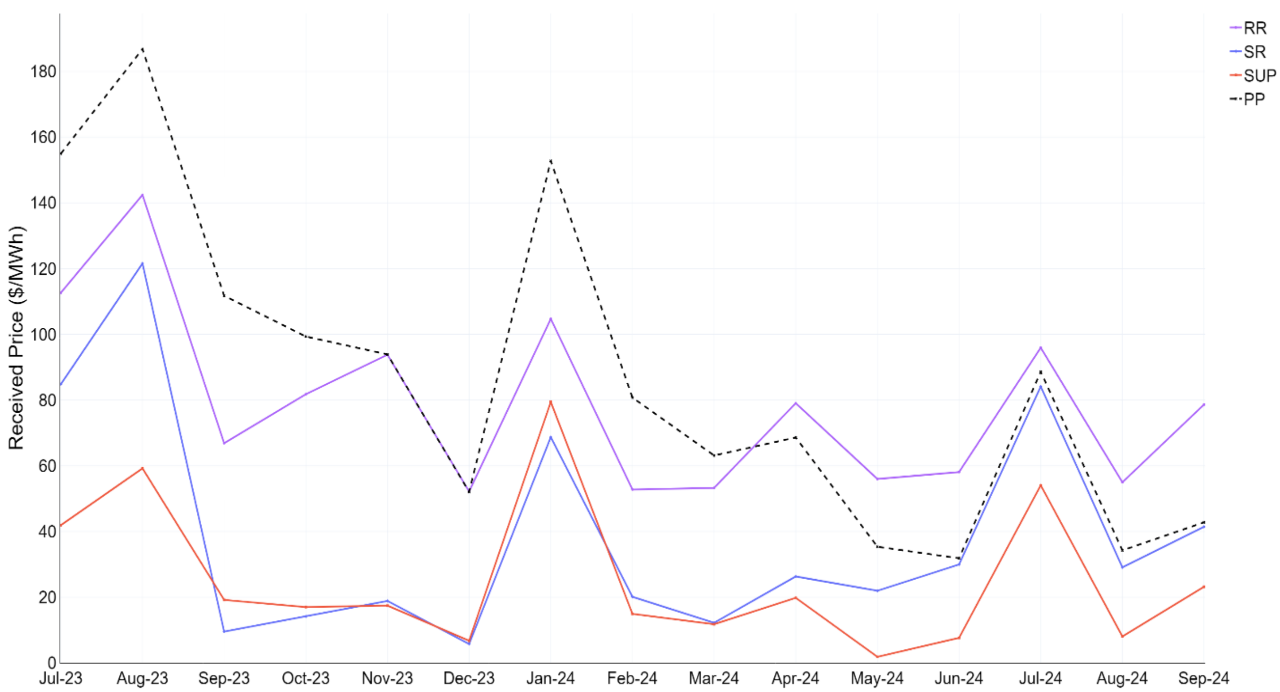


Table 12: Average received price for active regulating, spinning and supplemental reserves (Q2 2024 vs Q3 2024)

Qtr Year	Regulating Reserve	Spinning Reserve	Supplemental Reserve	Pool Price
Q2 2024	$64	$26	$10	$45
Q3 2024	$77	$52	$28	$55
Difference	$13	$26	$18	$10

Year-over-year, the quarterly average received prices for regulating, spinning, and supplemental reserves experienced a notable decline, dropping by 29%, 28%, and 29% respectively. This decline was primarily driven by a $96/MWh decrease in pool price (Table 13) resulting from increasing supply in the energy market (Section 1.1).

Table 13: Average received price for active regulating, spinning and supplemental reserves (Q3 2023 and Q3 2024)

Qtr Year	Regulating Reserve	Spinning Reserve	Supplemental Reserve	Pool Price
Q3 2023	$107	$72	$40	$151
Q3 2024	$77	$52	$28	$55
Difference	-$30	-$20	-$12	-$96

However, the year-over-year rise in the equilibrium prices offset some of the impact from the drop in pool prices, lessening the overall decline in received prices for OR. Figure 45 illustrates the equilibrium prices for on peak OR products from January 2023 to September 2024. Average equilibrium prices for on peak regulating, spinning, and supplemental reserve products increased by $71/MWh, $256/MWh, and $287/MWh, respectively year-over-year. Off peak equilibrium prices also experienced a year-over-year increase.

In Q3, there has been an increase in volumes procured by the AESO for all OR products, compared to the previous year, which has applied some upward pressure on equilibrium prices. In particular, the AESO increased their procurement volume for both on and off peak regulating reserve while the BC/MATL intertie was offline for scheduled maintenance in September. On September 23, active on peak regulating reserve volumes increased from 210 MW to 250 MW, and procured off peak volumes increased from 135 MW to 175 MW (Figure 46 and Figure 47).

Figure 45: Average equilibrium price for on peak regulating, spinning, and supplemental reserves by month (January 2023 to September 2024)

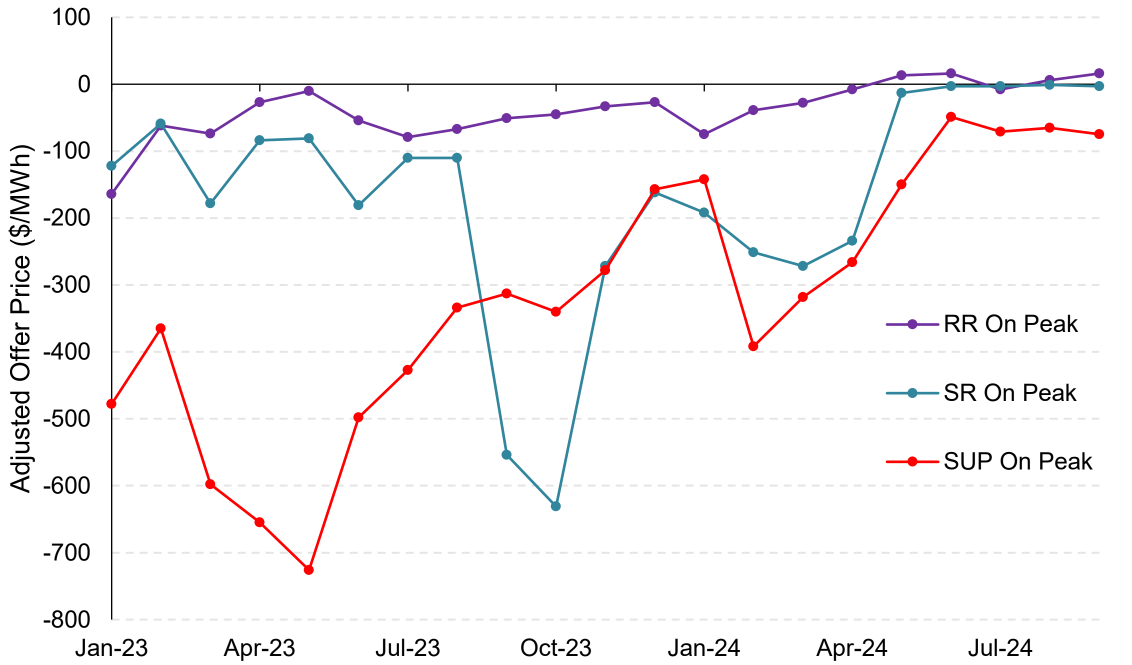


Figure 46: Active, standby and activated standby volumes for on peak regulating reserve (July 1, 2023 to September 30, 2024)

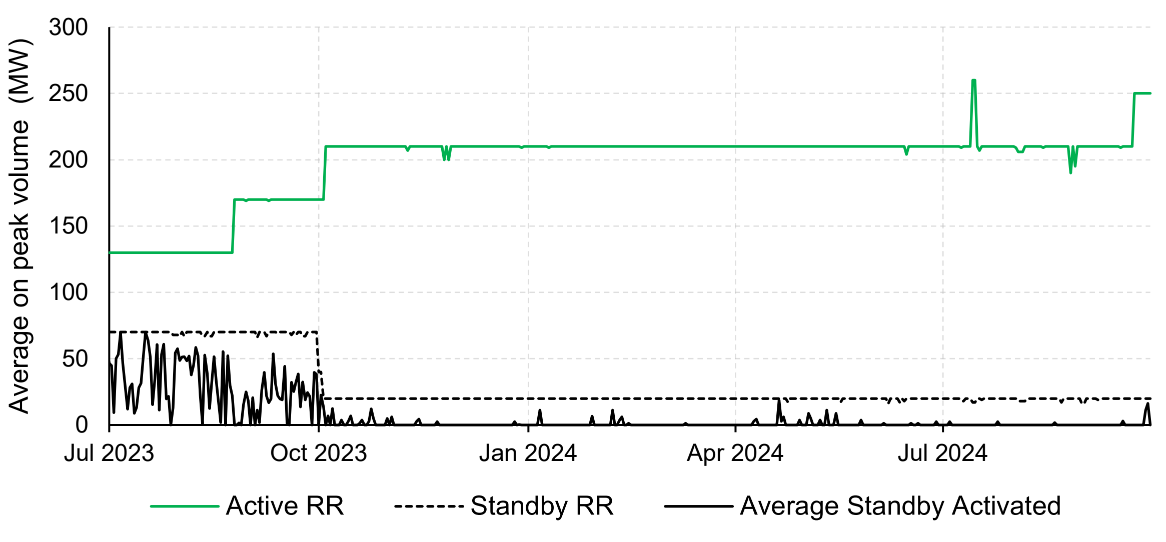
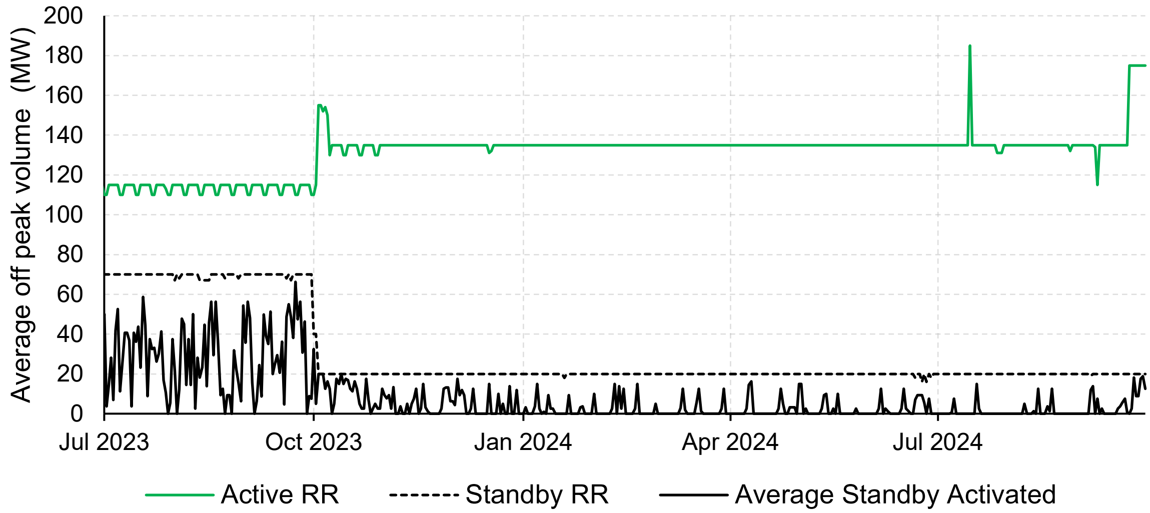


Figure 47: Active, standby and activated standby volumes for off peak regulating reserve (July 1, 2023 to September 30, 2024)



On peak supplemental reserves saw the highest increase in equilibrium prices year-over-year, primarily due to a decrease in the participation of loads. Substituting for the reduction in load participation, some energy storage assets have switched their focus from spinning reserve to the supplemental reserve market, offering substantial volumes at higher prices.

On the other hand, the decline in energy storage participation in the spinning reserve market has decreased competition in this market, leading to higher spinning reserve prices since April 2024. Figure 48 and Figure 49 illustrate daily offered volumes by fuel type for spinning and supplemental reserve from January 2023 to September 2024.

Figure 48: Spinning reserve offer volume by fuel type (on peak) (January 2023 to September 2024)

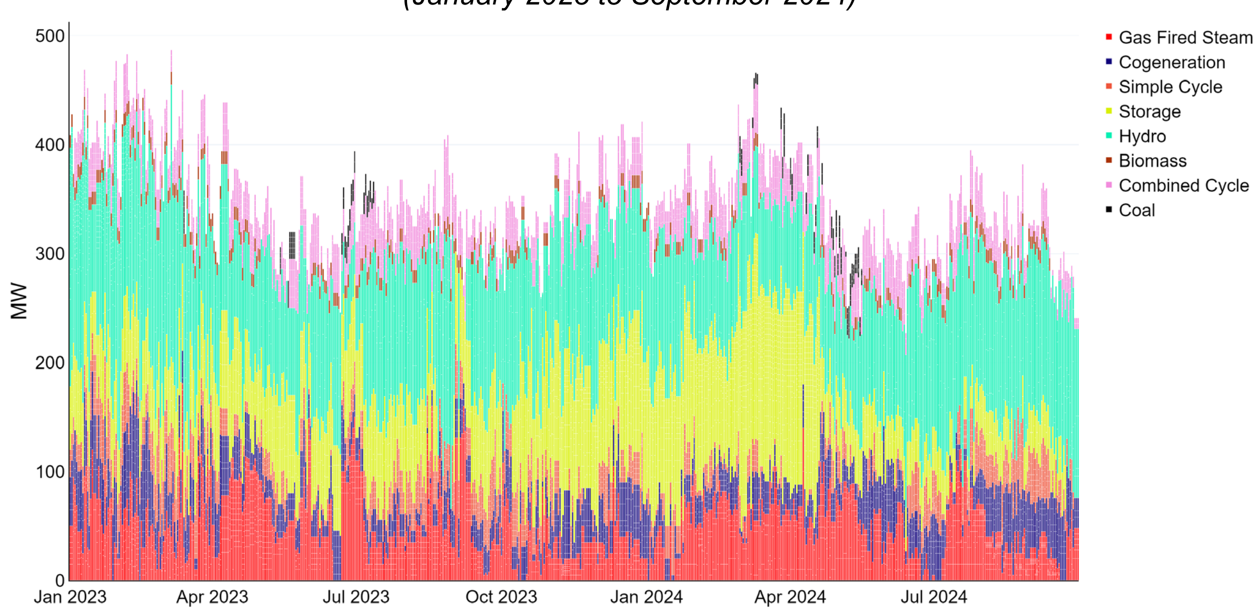
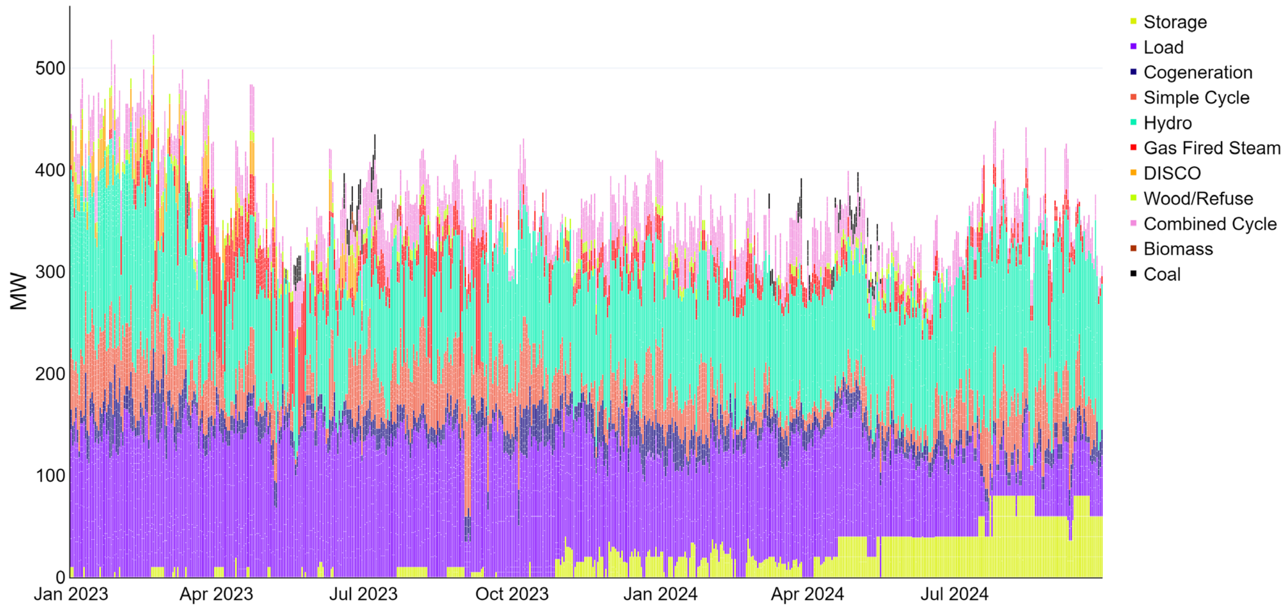


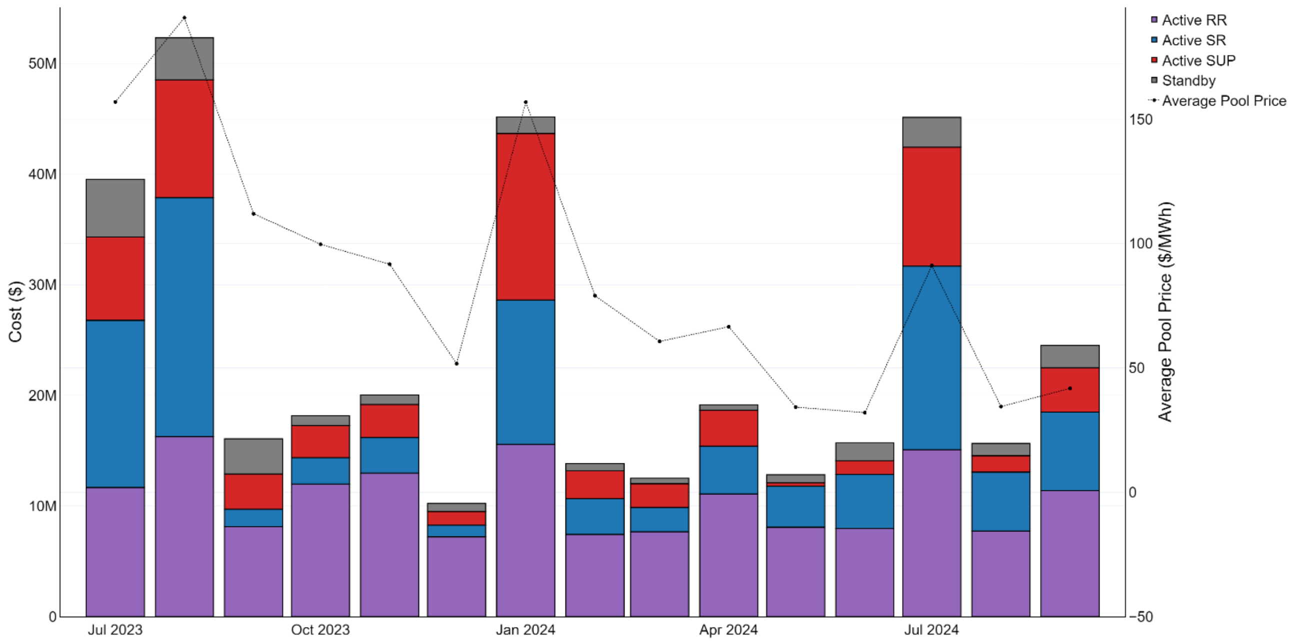
Figure 49: Supplemental reserve offer volume by fuel type (on peak) (January 2023 to September 2024)



3.2 Total operating reserve costs

Total OR costs increased by 79% from Q2 to Q3 (Figure 50) driven by higher pool prices and an increase in spinning and supplemental reserve equilibrium prices due to a changing supply mix and offer strategy (Section 3.1). Spinning reserve costs experienced the largest quarter-over-quarter increase in response to higher on peak equilibrium prices. While total operating reserve costs in Q3 surpassed Q2 levels, year-over-year costs declined by 21% due to a reduction in pool prices and standby costs.

Figure 50: Total cost of operating reserves by month (July 2023 to September 2024)



3.3 Operating reserve directives

Contingency reserves are directed by the AESO in the event of a large contingency, such as the sudden loss of a large generator. Table 14 highlights the total number of events requiring the use of contingency reserve directives in Q3 2024. Additionally, the table reports the average directive response by providers of spinning reserve and supplement reserve – with supplemental reserve being separated into load and generation.

In Q3 2024, there were 36 events which necessitated the need to direct contingency reserves. This is 10 more events than the previous quarter. In September, 63% of events occurred between September 23 and the end of the month, during which the BC/MATL intertie was offline due to a planned outage. This quarters longest contingency reserve directive occurred on September 23 at 17:21 in response to a rapid decline in solar output, causing system frequency to drop to 59.818 Hz. This event required a 40-minute response by supplemental reserve generators. Additionally, on September 28 at 19:54 the AESO directed all contingency reserve volumes (462 MW) in response to Cascade 1 tripping offline.

Table 14: Monthly contingency reserve directives (Q3 2024)

Month	Number of Events	Average SR Directed (MW)	Average SUPL Directed (MW)	Average SUPG Directed (MW)
July	14	127	45	88
August	6	119	26	107
September	16	121	38	99

3.4 Standby

Standby reserves are activated to supply additional volumes to the OR market when more reserves are required, for example when a supplier of active reserves has a forced outage. Figure 51 shows the combined on and off peak activation rates for regulating, spinning, and supplemental reserve. This quarter, the activation rates for regulating reserve remained low, decreasing by 2 percentage points, while activation rates for spinning and supplemental reserve both increased from 7% to 12% and from 7% to 13%, respectively.

Figure 51: Activation rates for regulating, spinning, and supplemental reserve (July 2023 to September 2024)

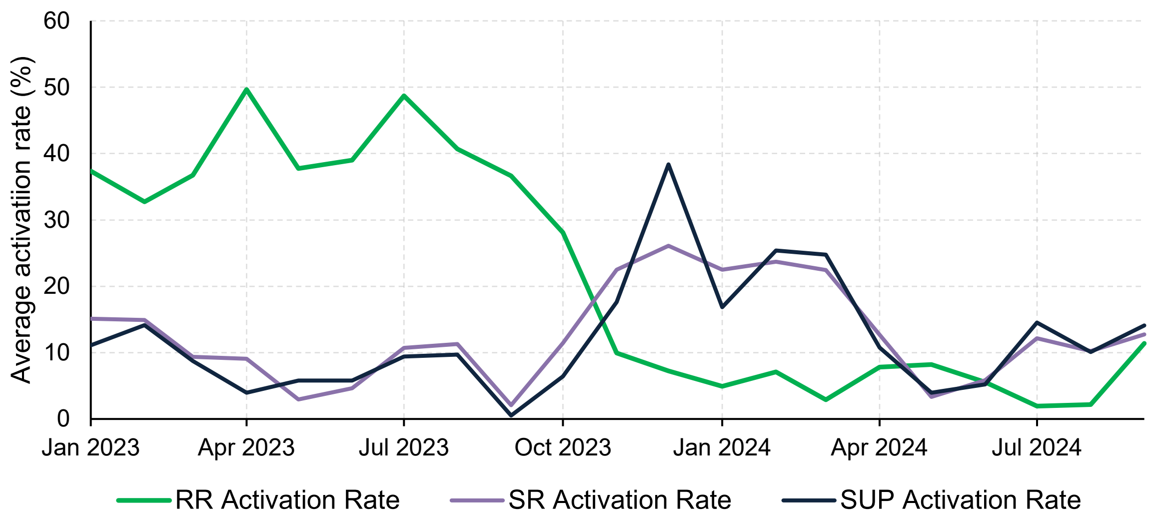
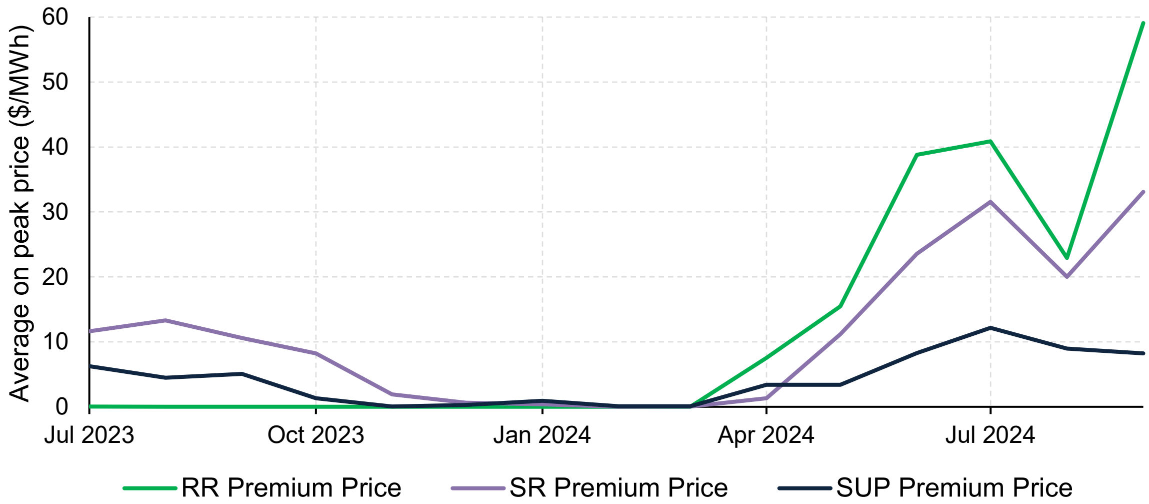


Figure 52 shows the monthly average on peak premium price for standby regulating, spinning, and supplemental reserves. Premium prices for both on and off peak operating reserve products continue to increase following the change in activation percentages last quarter (April 15, 2024).

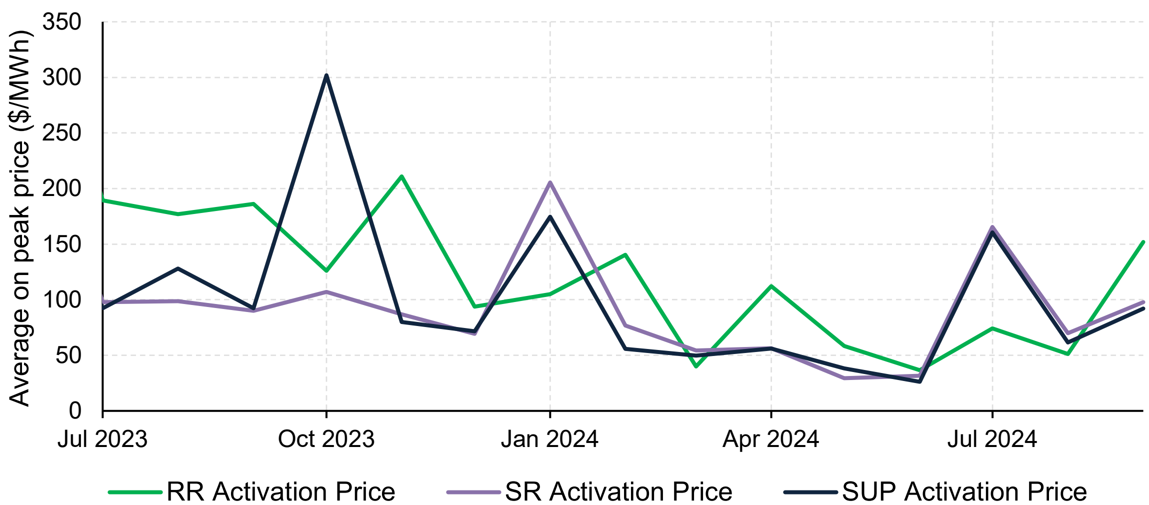
This increase was most notable in on peak regulating reserve, with a $20.46/MWh premium price hike quarter-over-quarter and a $40.83/MWh increase year-over-year. Premium prices for regulating and spinning reserves increased in September due to a reduction in offered volumes for both products.

Figure 52: Average on peak premium price (July 2023 to September 2024)



On peak activation prices for all products increased in Q3 relative to Q2. Activation prices in the previous quarter were particularly low in response to the change in activation rates. While year-over-year activation prices decreased for on peak regulating reserves by $48.69/MWh, spinning and supplemental reserves experienced an increase of $29.41/MWh and $11.64/MWh (Figure 53).

Figure 53: Average on peak activation price (July 2023 to September 2024)



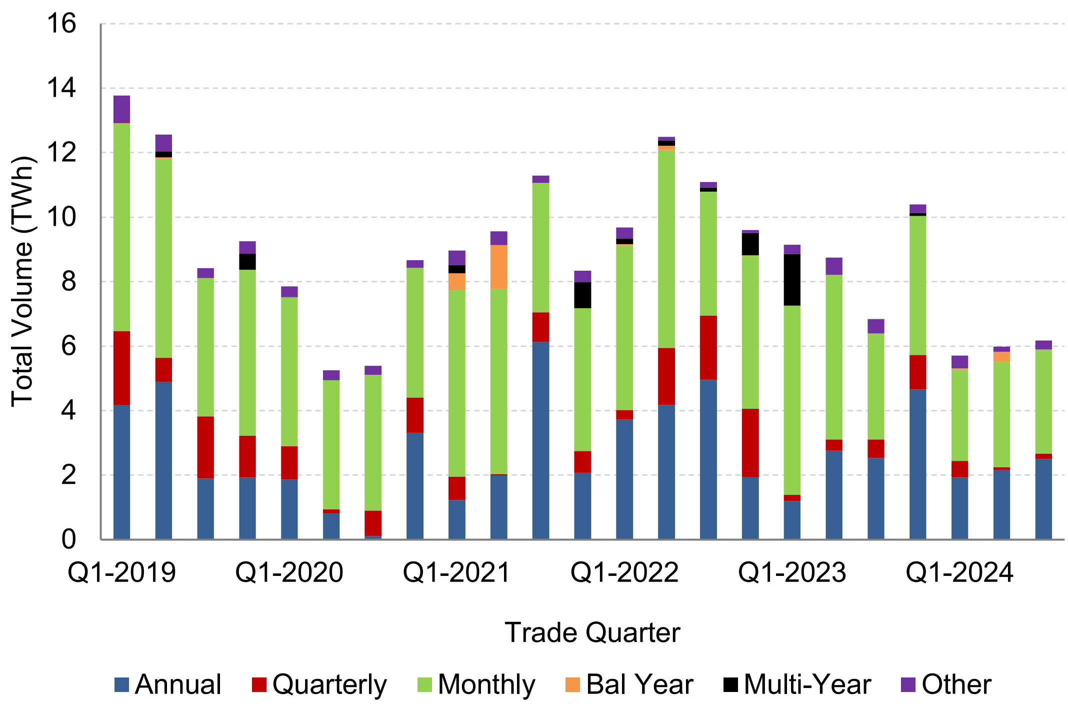
4 THE FORWARD MARKET

Alberta's financial forward market for electricity is an important component of the market because it allows for generators and larger loads to hedge against pool price volatility, and it enables retailers to reduce price risk by hedging sales to retail customers.[16]

4.1 Forward market volumes

Low liquidity in the forward market continued in Q3. Trade volumes on ICE NGX or through brokers totalled 6.18 TWh over the quarter, which represents a decline of 10% year-over-year. As shown by Figure 54, trade volumes so far in 2024 have been low. Indeed, total volumes in the first three quarters of 2024 have been comparable with the levels observed in Q2 and Q3 of 2020, when uncertainty around the COVID-19 pandemic reduced trading activity.

Figure 54: Total volumes by trade quarter and product term (excludes direct bilateral volumes) (Q1-2019 to Q3-2024)



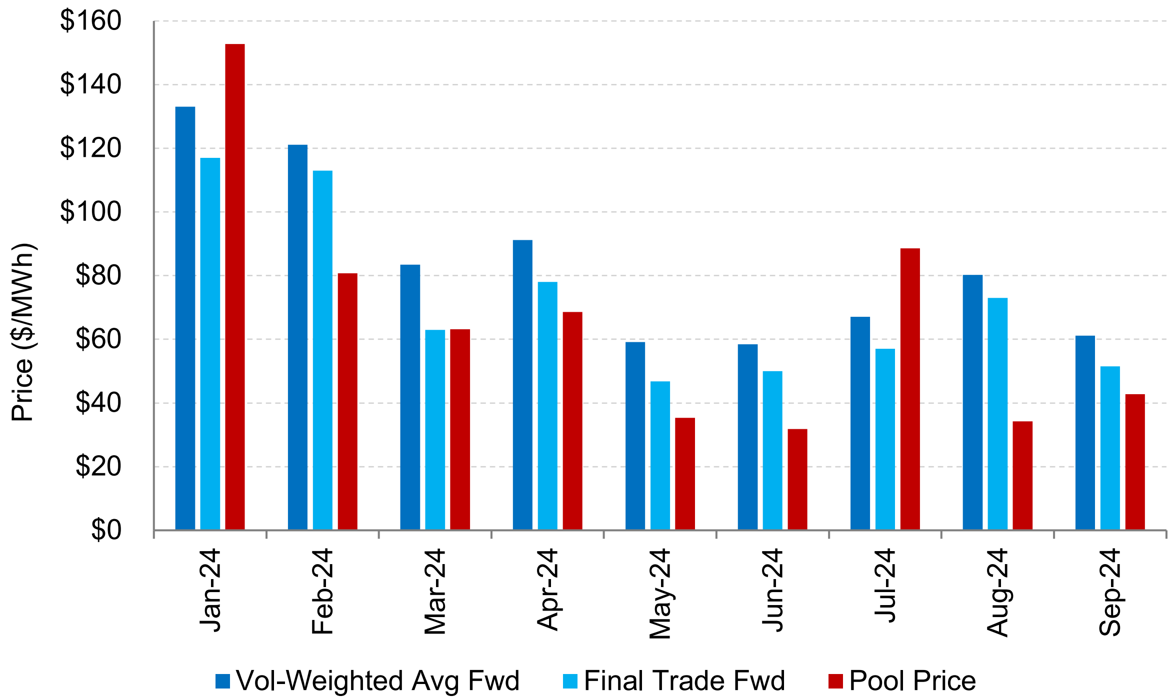
[16] The MSA's analysis in this section incorporates trade data from ICE NGX and two over the counter (OTC) brokers: Canax and Velocity Capital. Data from these trade platforms are routinely collected by the MSA as part of its surveillance and monitoring functions. Data on direct bilateral trades up to a trade date of December 31, 2023 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.

4.2 Trading of monthly products

Figure 55 compares monthly flat forward prices with realized average pool prices. The average pool price in July was $88.62/MWh, which was above forward market expectations with a volume-weighted average forward price of $67.05/MWh and a final forward price of $57.00/MWh. High temperatures and low wind generation were some of the main factors which increased pool prices in July above forward market expectations.

In August and September pool prices came in below forward market expectations. In August the average pool price was $34.26/MWh, well below forward prices with the volume-weighted average forward price of $80.26/MWh and a final forward price of $73.00/MWh. In contrast with July, weather conditions in August were mild and this lowered demand putting downward pressure on pool prices.

Figure 55: Monthly flat forward prices and realized average pool prices by month (January 2024 to September 2024)



The evolution of select monthly forward prices over the course of Q3 is shown in Figure 56. The dashed lines in the figure illustrate the marked prices for July, August, and September. These marked prices combine realized prices and forward prices for balance-of-month to calculate the expected average price for a month as of a certain date.

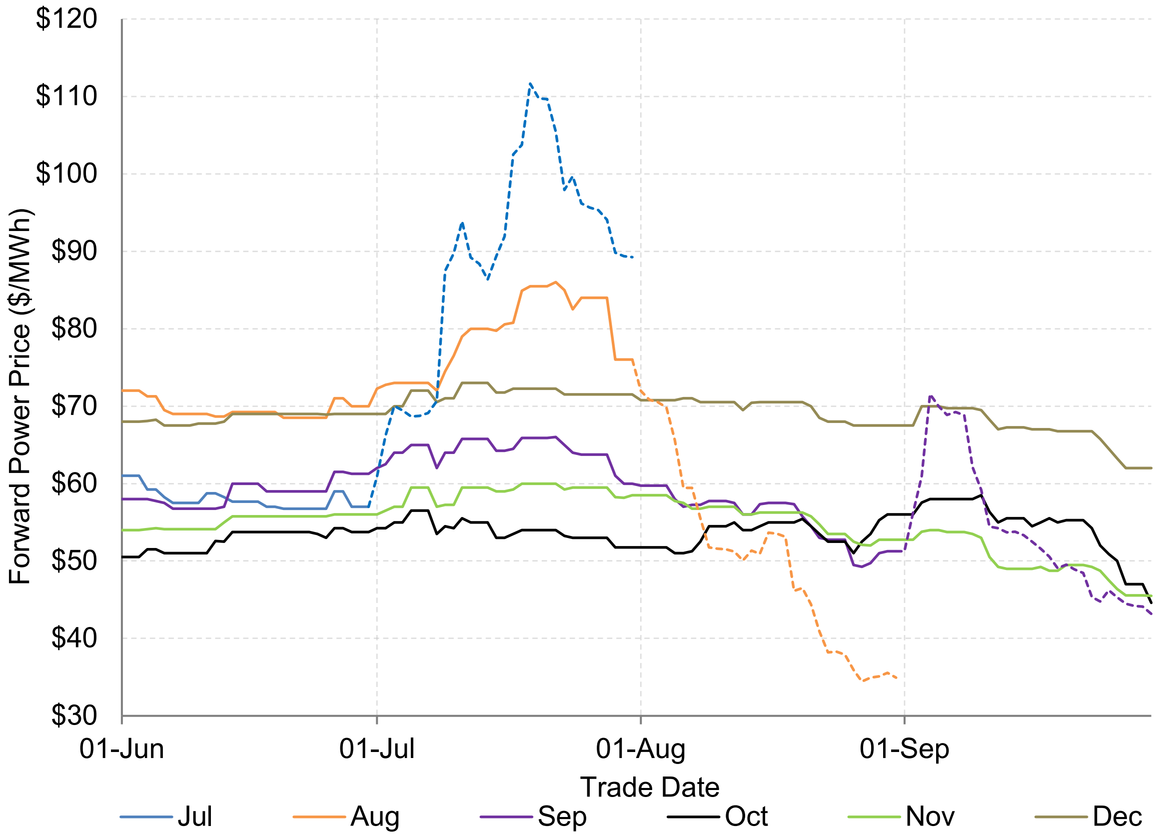
Events in the energy market during Q3 influenced forward prices. For example, the pool price volatility in early July put upward pressure on forward prices, particularly for August. Conversely, when pool prices came in below market expectations in late August this put downward pressure on forward prices.

In early September, forward prices rose along with the high pool prices as the expected price of September increased from $51.25/MWh on August 31 to $71.55/MWh on September 4. However forward prices later declined as pool prices came in below expectations causing the marked price of September to fall, with the month eventually settling at $42.80/MWh.

Falling natural gas futures also put downward pressure on monthly contract prices over the quarter. For example, the natural gas price for October fell from $1.05/GJ to $0.47/GJ over Q3, a decline of 55%, while natural gas prices for November and December fell by 29% and 18%, respectively.

The forward price for October increased in early and late August with the latter increase taking the price of October above September and November. The price of October increased on the back of a number of planned thermal generator outages which were scheduled to occur in October.

Figure 56: The evolution of select monthly flat forward prices (June 1 to September 30)



4.3 Trading of annual products

The marked price of Calendar 2024 (CAL24) peaked at $73.47/MWh on July 20 before declining to end the quarter at $62.59/MWh. The decline in the marked price of CAL24 meant that in late September the expected price of CAL24 fell below the forward price of CAL28 for the first time.

Annual forward prices were largely unchanged for much of Q3 but the prices of CAL25 and CAL26 declined in late September in response to the low pool prices in the energy market, and the large number of hours settling at the $0.00/MWh price floor. The price of CAL25 fell from $50.00/MWh on September 17 to $46.50/MWh on September 26, a decline of 7%.

Forward prices for natural gas fell significantly over the quarter with the price of natural gas for CAL25 falling by 25% and the price of CAL26 falling by 19%. As a result, the estimated operating margin for a hypothetical combined cycle asset increased over Q3 for all years (Table 15). The estimated operating margin for CAL27 increased by 24% as the price of power for CAL27 increased slightly while the price of natural gas fell by 17%.

Figure 57: Annual flat forward prices (January 1 to September 30)

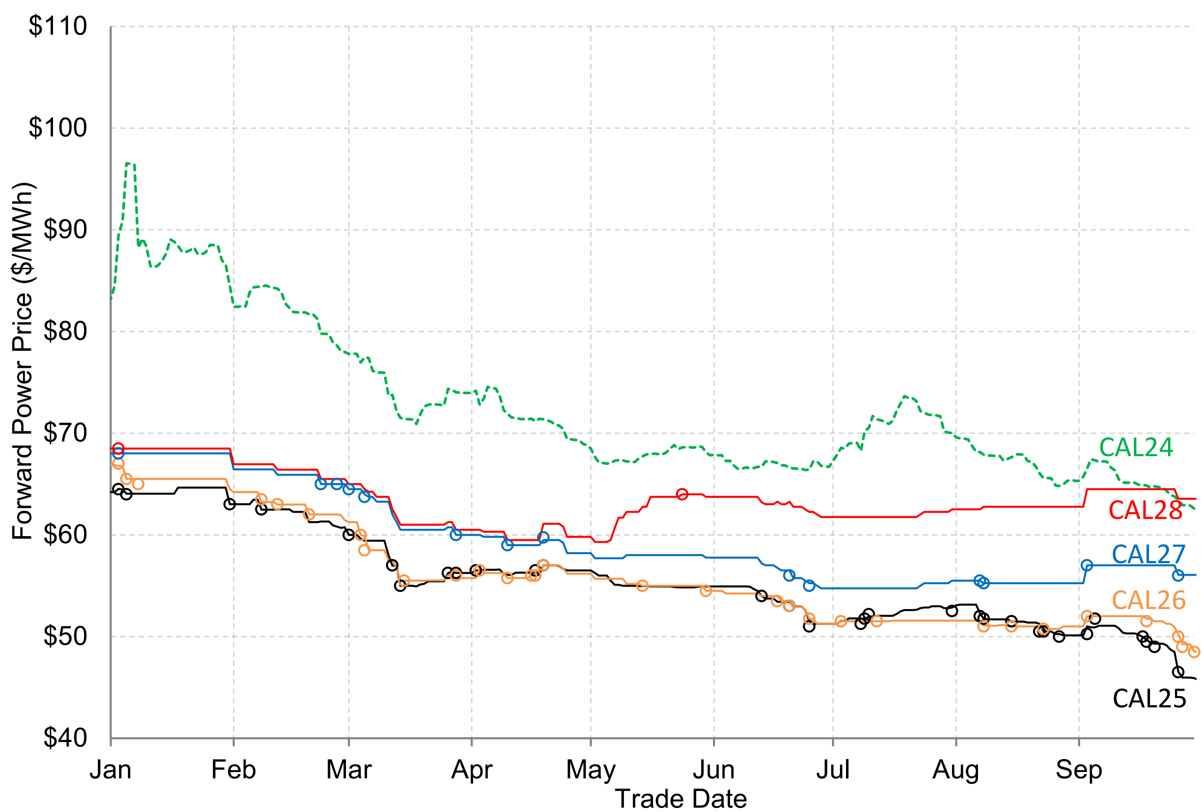


Table 15: Forward power and natural gas price changes over Q1

Contract	Power price ($/MWh)			Natural gas price ($/GJ)			Operating margin[17] ($/MWh)		
	Jun 30	**Sep 30**	**% Chg**	**Jun 30**	**Sep 30**	**% Chg**	**Jun 30**	**Sep 30**	**% Chg**
CAL24 (marked)	$66.70	$62.59	-6%	$1.94	$1.30	-33%	$51	$52	1%
CAL25	$51.24	$45.91	-10%	$3.11	$2.33	-25%	$26	$26	2%
CAL26	$51.24	$48.50	-5%	$3.51	$2.85	-19%	$22	$24	10%
CAL27	$54.75	$56.05	2%	$3.51	$2.93	-17%	$24	$30	24%
CAL28	$61.75	$63.55	3%	$3.41	$2.96	-13%	$30	$35	17%

[17] The operating margin figures assume a heat rate of 7.5 GJ/MWh and consider the carbon costs associated with an emissions intensity of 0.37 tCO2e/MWh.

5 THE RETAIL MARKET

5.1 Quarterly summary

Residential retail customers can choose from several retail energy rates. By default, retail customers are on the regulated rate option (RRO). RRO prices vary monthly and by distribution service area.

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

The average residential RRO rate in Q3 this year decreased by 59% compared to Q3 2023 (Table 16) but remained relatively consistent with the rates in Q2 2024. The RRO rates shown in Table 16 include the collection rates.[18] The collection rates increased the RRO rates in July, August and September by around 3.1 ¢/kWh, 3.3 ¢/kWh and 3.5 ¢/kWh respectively. Effective January 1, 2025, the RRO will be replaced with Rate of Last Resort (RoLR). Additional information about RoLR is provided later in this section.

Table 16: Monthly retail market summary for Q3 (Residential customers)

		2023	2024	Change
RRO (Avg ¢/kWh)	Jul	27.50	11.86	*-57%*
	Aug	32.27	13.19	*-59%*
	Sep	27.63	11.17	*-60%*
	Q3	**29.15**	**12.08**	***-59%***
DRT (Avg $/GJ)	Jul	2.45	0.64	*-74%*
	Aug	3.21	1.33	*-58%*
	Sep	2.85	0.84	*-70%*
	Q3	**2.84**	**0.94**	***-67%***
Competitive Variable Electricity Rate (Avg. ¢/kWh)	Jul	18.09	11.35	*-37%*
	Aug	21.49	4.65	*-78%*
	Sep	12.70	5.81	*-54%*
	Q3	**17.48**	**7.29**	***-58%***
Competitive Variable Natural Gas Rate (Avg. $/GJ)	Jul	3.42	1.92	*-44%*
	Aug	3.61	1.58	*-56%*
	Sep	3.44	1.46	*-58%*
	Q3	**3.49**	**1.66**	***-53%***
Expected Cost, 3-Year Electricity Contract (Avg. ¢/kWh)	Jul	10.27	5.69	*-45%*
	Aug	9.16	5.52	*-40%*
	Sep	8.51	5.46	*-36%*
	Q3	**9.32**	**5.56**	***-40%***
Expected Cost, 3-Year Natural Gas Contract (Avg. $/GJ)	Jul	3.45	2.87	*-17%*
	Aug	3.64	2.84	*-22%*
	Sep	3.47	2.72	*-22%*
	Q3	**3.52**	**2.81**	***-20%***

The average residential Default Rate Tariff (DRT) rate in Q3 this year also declined, by 67% relative to last year (Table 16). The quarterly average DRT rate of $0.94/GJ in Q3 marked the lowest ever recorded. In Q3, DRT rate was lowest in July and highest in August. The average DRT rate of $0.64/GJ in July, across all service areas, is the lowest since July 2019.

The average competitive variable electricity rate faced by residential customers was 58% lower year-over-year. Variable electricity rates were in line with pool prices in that they were lowest in August and highest in July.

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[18] Collection rates result from the deferred revenue associated with the rate ceiling set on RRO rates for January, February, and March 2023. The deferred revenue is being recovered from the RRO customers from April 2023 until December 2024

The average competitive variable natural gas rates in Q3 also experienced a 53% year-over-year decline. Variable natural gas rate was lowest in September and highest in July (Table 16).

Retailers' expected cost of providing 3-year fixed rate electricity contracts in Q2 was 40% lower year-over-year and 5% lower than in Q2 2024. The expected cost of providing 3-year fixed rate natural gas contracts dropped by 20% year-over-year and by 13% relative to Q2 2024.

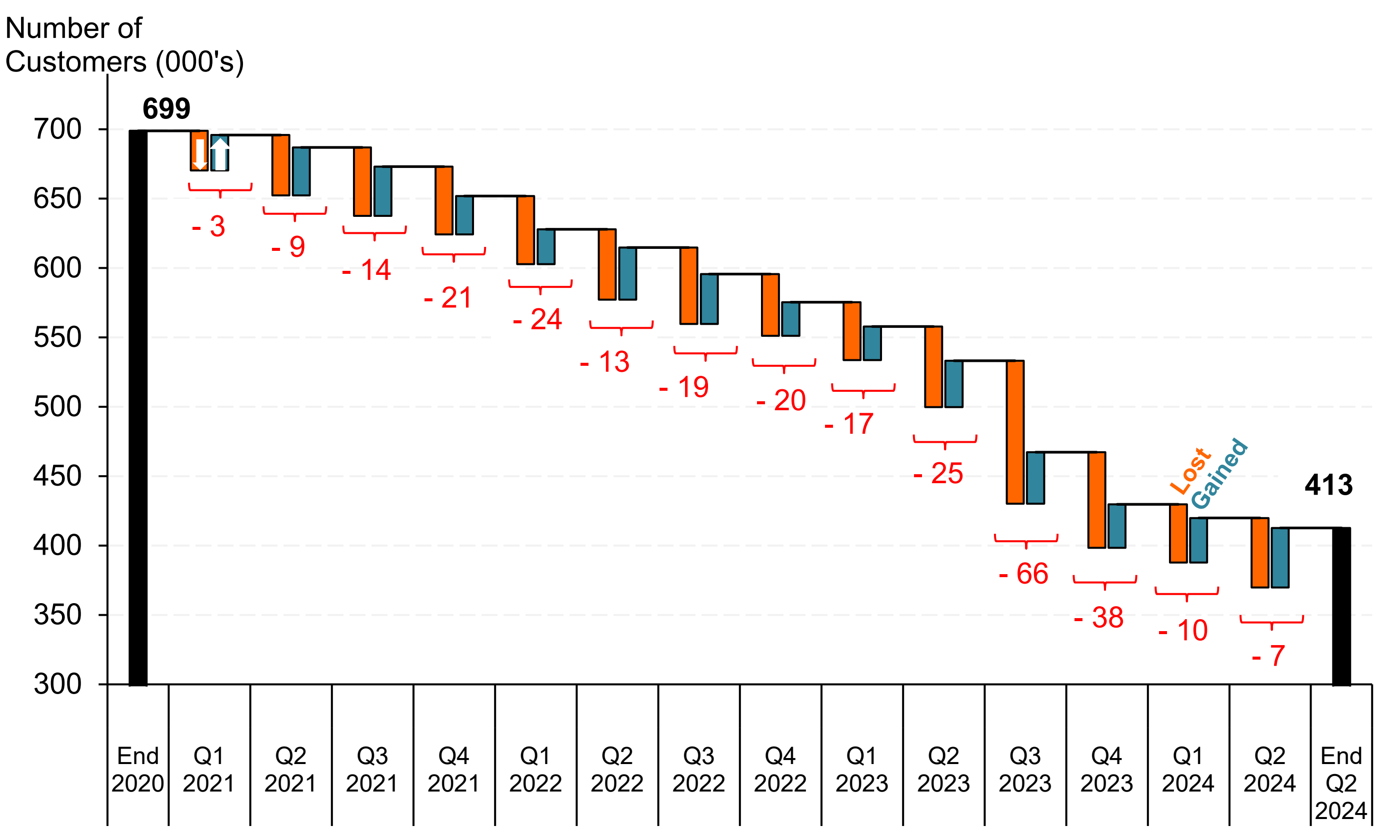
5.2 Retail customer movements

The MSA collects and tracks retail switching data on a one-quarter lagged basis. As such, the discussion in this section focuses on retail switching in and prior to Q2 2024.

5.2.1 Regulated retailer customer losses

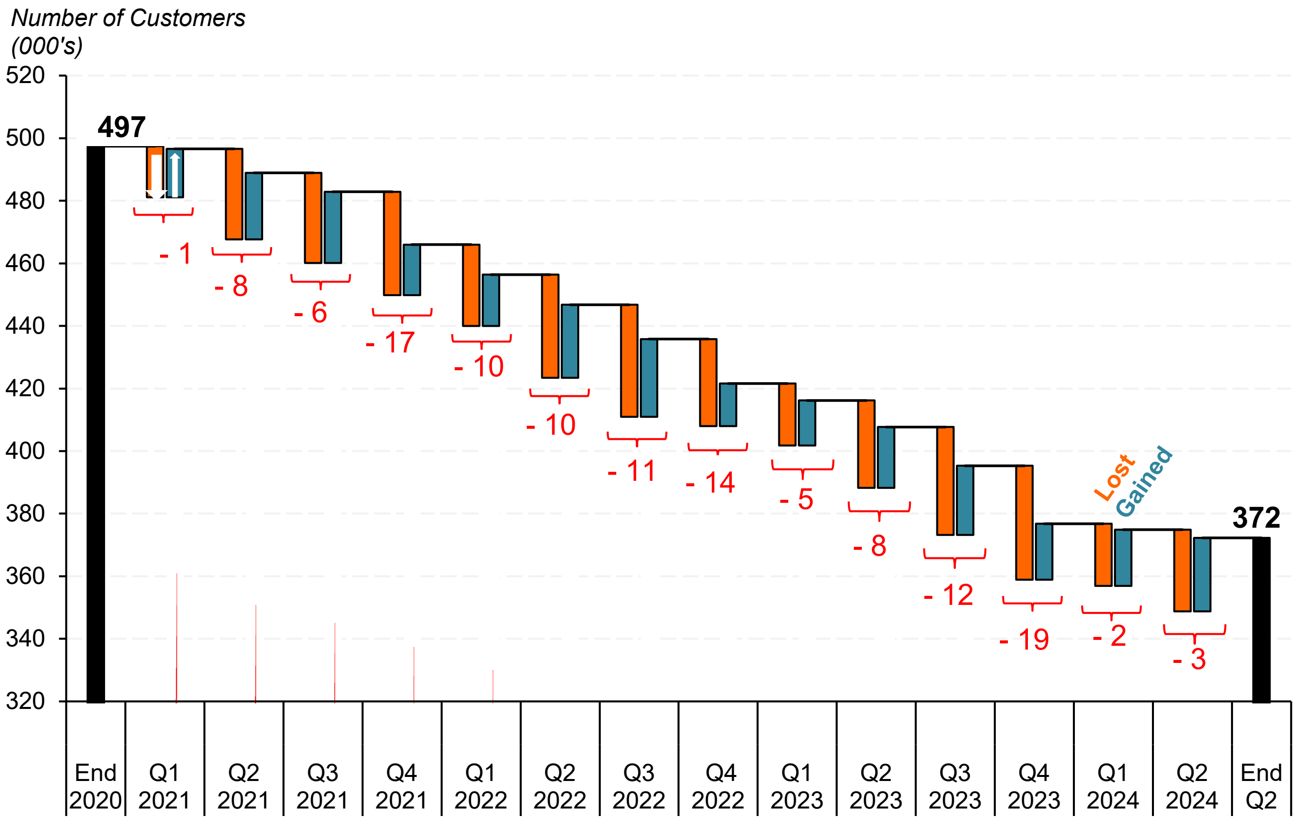
In Q2, the net residential RRO customer loss was approximately 7,000, marking the lowest loss since Q2 2021 (Figure 58). While around 50,000 residential customers left the RRO, approximately 43,000 customers joined the RRO in Q2. The gain of 43,000 new customers in Q2 is the highest number of residential customers joining the RRO in a quarter since Q3 2013. The RRO rates in April, May, and June (excluding collection rates) were comparable to or even lower than some of the available fixed-rate electricity contract pricing. This may have contributed to the increased number of RRO customers gained in Q2. As of June 2024, there are around 413,000 residential customers on the RRO.

Figure 58: RRO customer net losses, residential customers (Q1 2021 to Q2 2024)



The DRT customer net loss in Q2 was approximately 3,000, slightly higher than in Q1, but lower than to the losses observed in all other quarters since Q1 2021 (Figure 59). While around 26,000 customers left the DRT, around 23,000 new customers joined. In Q2, both customer departures from the DRT and new enrollments into the DRT were at the highest in May. As of June 2024, there are around 372,000 residential customers on DRT.

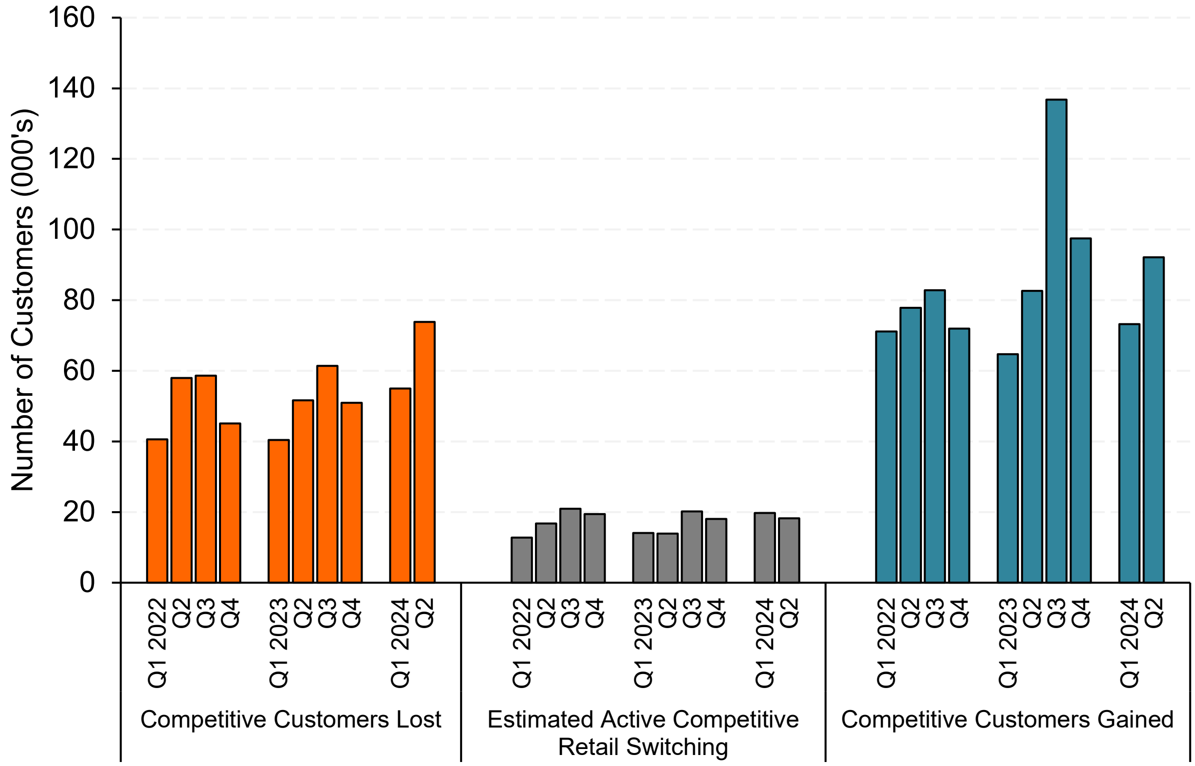
Figure 59: DRT customer net losses, residential customers (Q1 2021 to Q2 2024)



5.2.2 Competitive retailer customer gains

Customers leaving the RRO typically choose to enter the competitive market. The competitive customers gained in Q2 was approximately 92,000, a 26% increase over Q1 2024. At the same time 74,000 left the competitive market, a 34% increase over Q1 2024 (Figure 60). Out of the 74,000 customers who left in Q2, the MSA estimates that around 18,000 residential customers left their competitive retailer for reasons unrelated to a move or as a result of being dropped by their retailer. The MSA counts such a switch as an 'Active Switch', as the decision to leave for these customers may be motivated by economic factors, such as a decision to change retailers to take advantage of a competing rate offering. The count of active switches has remained consistent or close in the last few quarters (Figure 60).

Figure 60: Competitive electricity customer losses & gains, Q1 2022 to Q2 2024 (residential customers)



5.2.3 Competitive retailer market share

The competitive retail electricity market has shown only a marginal increase in market share during Q2, with a 0.60% growth from 74.39% in March to 74.98% in June (Figure 61). This limited growth can be attributed to the comparable pricing between competitive fixed-rate options and the default regulated rate (RRO), which may have reduced the incentive for consumers to switch to competitive offerings. The increase in market share (electricity) was highest in the ATCO Electric service area at 0.9%, and lowest in ENMAX service area at 0.2% (Table 17).

The competitive natural gas market also experienced only a slight increase in Q2, with market share rising by 0.31%, from 71.24% in March to 71.56% in June. In Q2, the Apex service area recorded the largest increase in market share (0.5%), while the ATCO Gas South service area had the lowest growth of 0.2% (Table 18).

Figure 61: Competitive retail customer share (electricity) by service area, residential customers (January 2015 to June 2024)

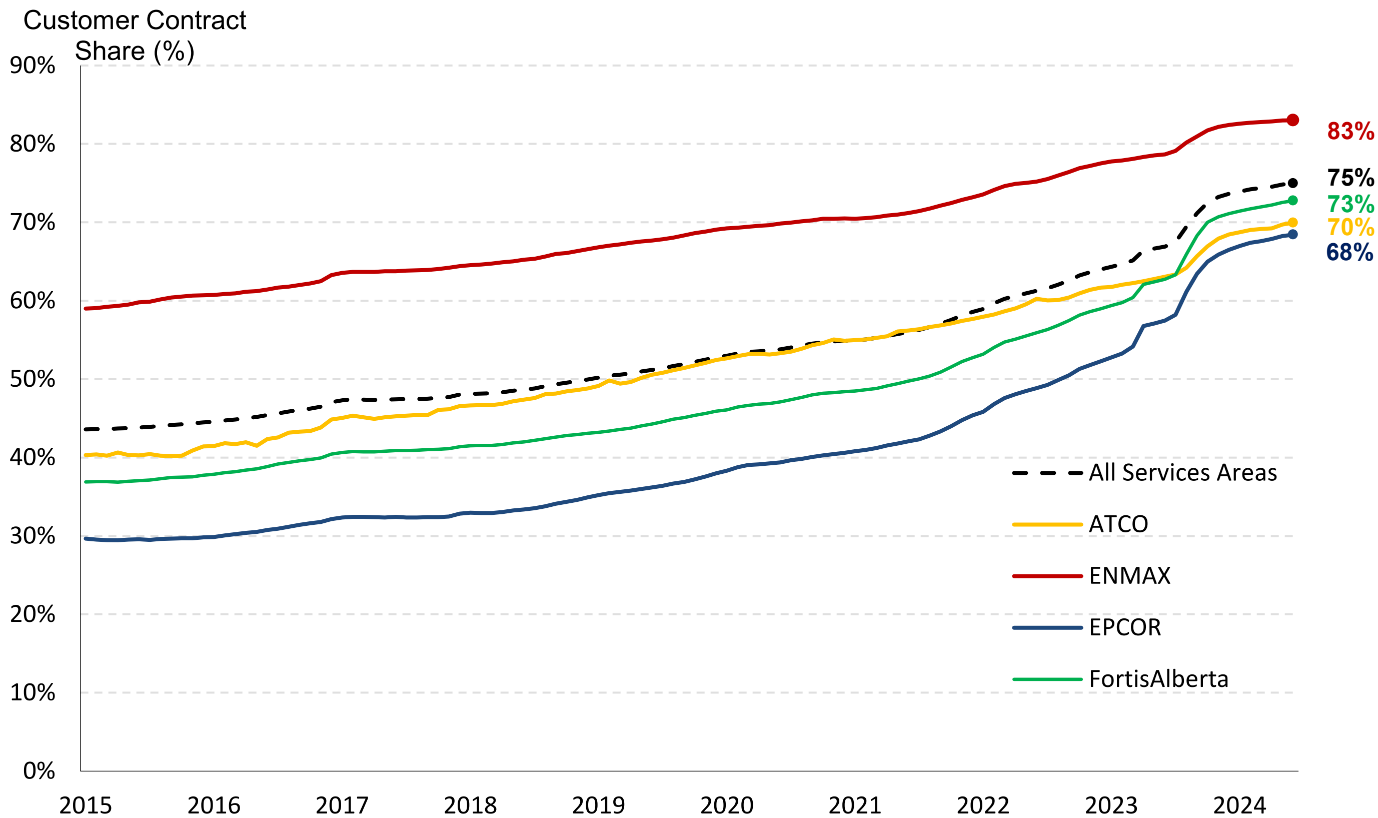


Table 17: Change in retail competitive shares (electricity) by service area, residential customers

	ENMAX	EPCOR	FortisAlberta	ATCO
Change (Q1 - 2024)	+ 0.4%	+ 1.1%	+ 0.9%	+0.7%
Change (Q2 - 2024)	+ 0.2%	+ 0.8%	+ 0.8%	+0.9%
Competitive Share (June 2024)	83.0%	68.4%	72.8%	70.0%

Figure 62: Competitive retail customer share (natural gas) by service area, residential customers (January 2015 to June 2024)

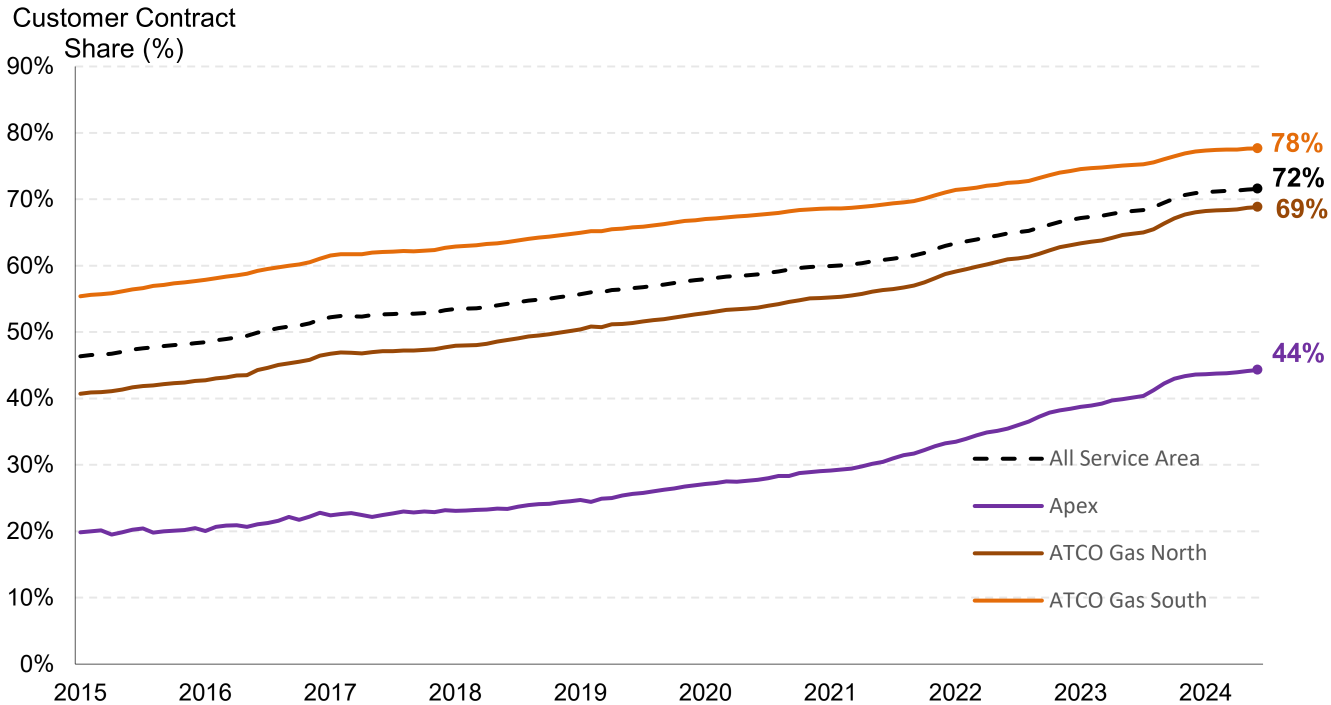


Table 18: Change in retail competitive shares (natural gas) by service area, residential customers

	ATCO Gas North	ATCO Gas South	Apex
Change (Q1 - 2024)	+ 0.4%	+ 0.3%	+ 0.2%
Change (Q2 - 2024)	+ 0.4%	+ 0.2%	+ 0.5%
Competitive Share (June 2024)	68.8%	77.7%	44.3%

5.3 Competitive fixed retail rates

Most retail customers can choose to sign a contract with a competitive retailer instead of remaining on regulated rates. Competitive retailers typically offer fixed and variable energy rates. Fixed rates are fixed over a defined contract term; usually one, three or five years. Variable rates are energy rates that vary by month and can be tied to pool prices or regulated rates.

Retailers offering fixed rates to customers face energy costs associated with that customer's consumption over the length of the contract term. The MSA refers to these energy costs as expected costs.[19] In the long-run, competitive retailers may adjust the fixed rates offered to new

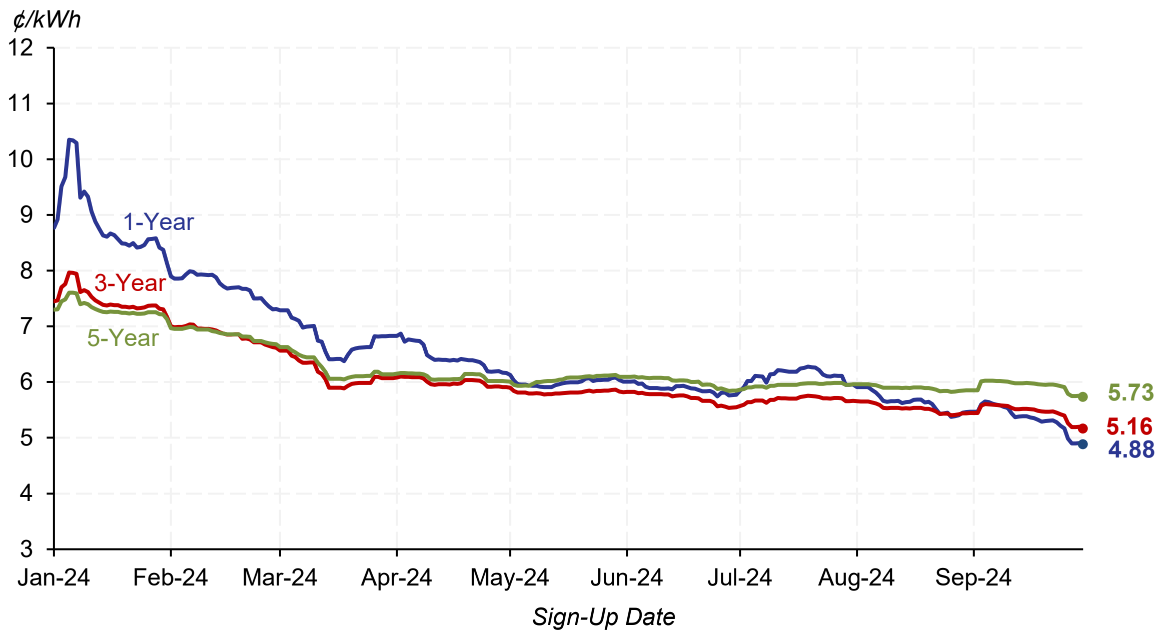
[19] "Expected costs" as used here is a risk-free metric that assumes future prices and load is known with certainty.

customers in response to changes in the expected cost of fixed rate contracts as retailers compete for customers.

The MSA calculates retailer expected costs of serving residential customers based on prevailing forward settlement prices. Earlier this year, the expected cost of a 1-year contract was higher than that of 3- and 5-year contracts, a trend consistent with previous years. However, the 1-year expected cost has since decreased significantly, now falling below the expected costs of both 3- and 5-year contracts (Figure 63). This shift is due to nearby annual contracts, such as Cal 25 and Cal 26, being priced lower than the more distant annual contracts, such as Cal 27 and Cal 28 (Figure 57).

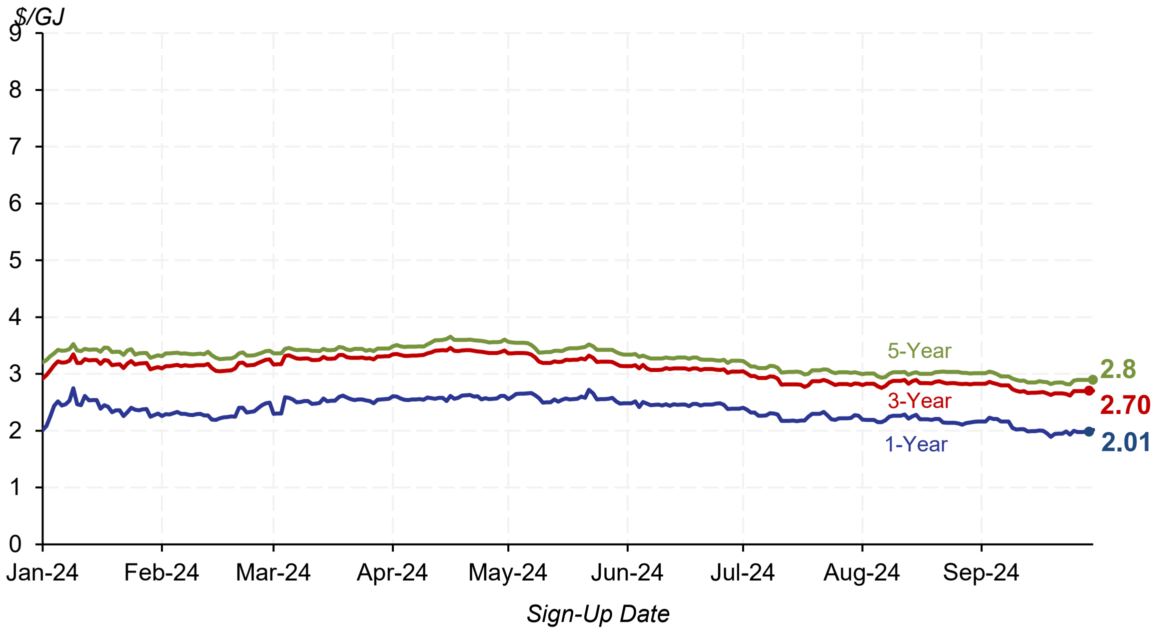
The expected cost for 1-, 3-, and 5-year fixed rate electricity contracts generally decreased in Q3. Expected cost dropped by 15%, 7%, and 2% for 1-, 3-, and 5-year contracts respectively. The expected cost for 1-year contracts increased in July, driven by a rise in near-term monthly power contract prices. However, these costs dropped significantly in August and September. Meanwhile, the cost of 3- and 5-year contracts remained relatively stable, with a slight decline observed towards the end of September. On September 30, the expected cost for 1-, 3-, and 5-year fixed rate electricity contracts were at 4.88 ¢/kWh, 5.16 ¢/kWh and 5.73 ¢/kWh respectively (Figure 63).

Figure 63: Expected cost, fixed rate electricity contract, residential customer (January 1, 2024 to September 30, 2024)



In Q3, the expected costs for 1, 3, and 5-year natural gas contracts also declined, consistent with the drop in forward natural gas prices (Figure 64). Expected costs declined by 17%, 11%, and 10%, respectively, for 1, 3, and 5-year gas contracts. On September 30, the expected cost for 1-, 3-, and 5-year fixed rate natural gas contracts are at $2.01/GJ, $2.70/GJ and $2.89/GJ respectively. (Figure 64).

Figure 64: Expected cost, fixed rate natural gas contract, residential customer (January 1, 2024, to September 30, 2024)



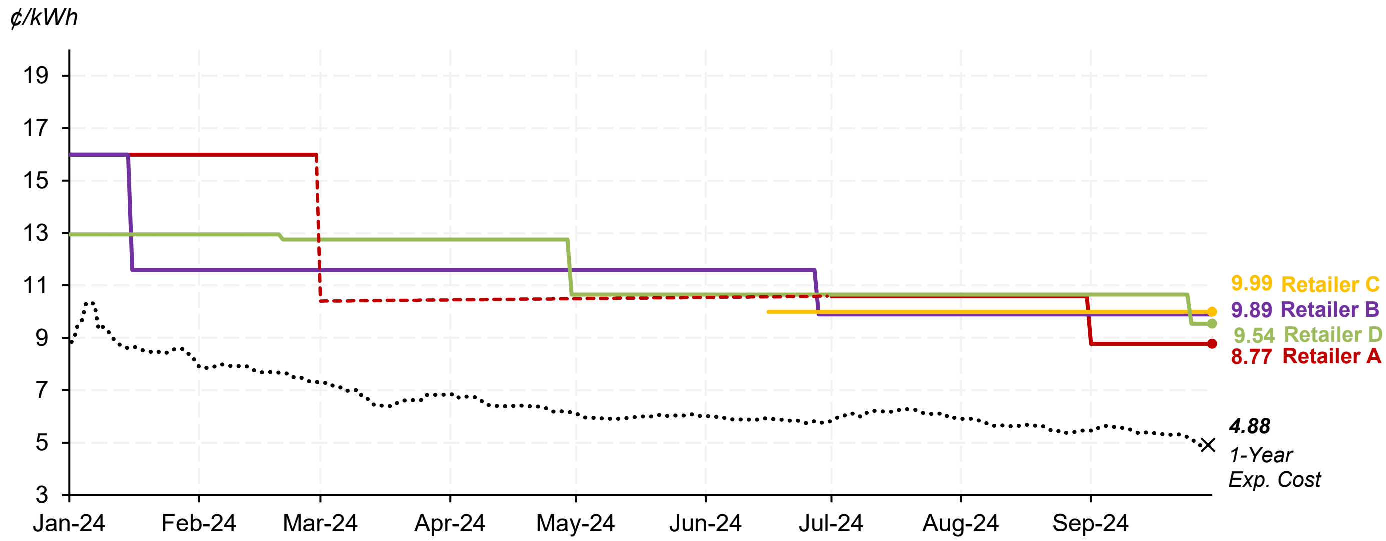
No fixed rate electricity retail provider raised their rates in Q3, as the expected cost decreased (Figure 65). Retailer A discontinued their limited time offer of 7.77 ¢/kWh, which was available from March 1 to June 30. During this period Retailer A was able to increase their residential customer base, which can be attributed to the appeal of their limited-time offer. Retailer E discontinued offering 3-year fixed-rate electricity contracts and instead started to provide 2-year fixed-rate contracts. As of September 30, Retailer E's 2-year fixed rate electricity contract was priced at 11.09 ¢/kWh. Retailer C, which recently began offering 1- and 3-year fixed-rate contracts, did not make any changes to their rates in Q3. No provider of 5-year fixed-rate electricity contracts made any changes to their pricing in Q3.

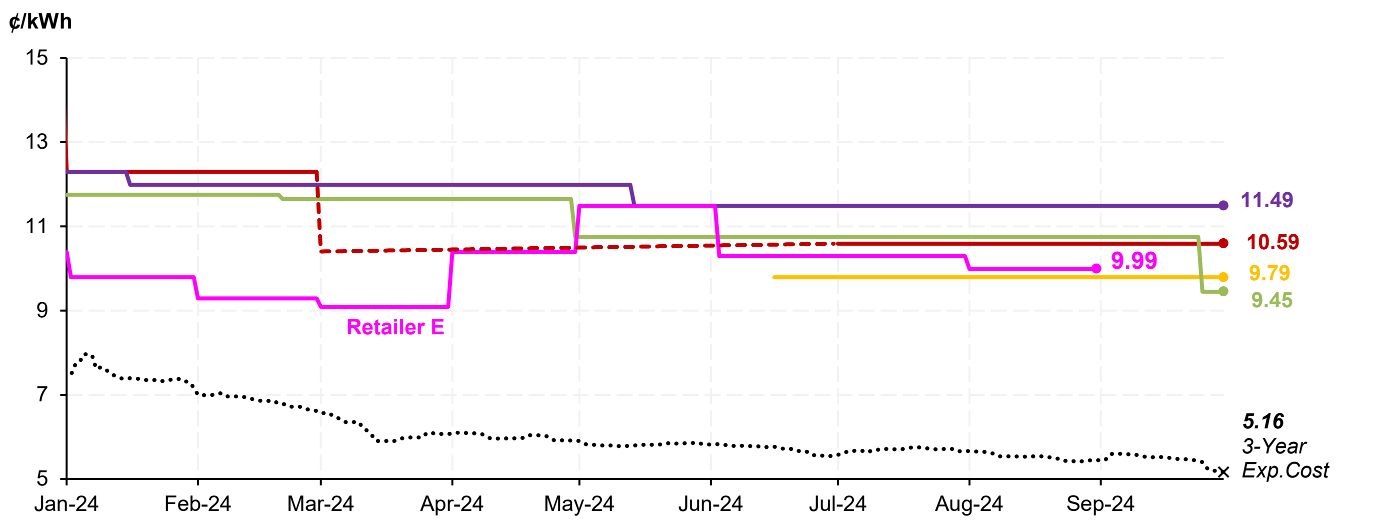
As of September 30, Retailer A offers the lowest one-year fixed rate electricity contracts at 8.77 ¢/kWh. Retailer D provides the lowest three-year fixed rate electricity contracts at 9.45 ¢/kWh, while Retailer F offers the lowest five-year fixed rates at 9.79 ¢/kWh (Figure 65).

Similar to Q2, most retailers kept their 1-, 3-, and 5-year fixed-rate natural gas contract prices unchanged in Q3. However, Retailer E increased their 3-year fixed rate from $4.59/GJ to $5.39/GJ in September. Retailer A reduced their 1-year fixed rate from $4.79/GJ to $3.77/GJ in late August while keeping their 3- and 5-year rates largely unchanged (Figure 66).

As of September 30, Retailer A offers the lowest one-year fixed rate natural gas contracts at 3.77 $/GJ. Retailer C provides the lowest three-year fixed rate natural gas contracts at 4.59 $/GJ, while Retailers B and G offer the lowest five-year fixed rates at 4.79 $/GJ (Figure 66).

Figure 65: 1-, 3-, and 5-year fixed rate electricity contract prices, residential customers, ENMAX service area (January 1, 2024 to September 30, 2024)





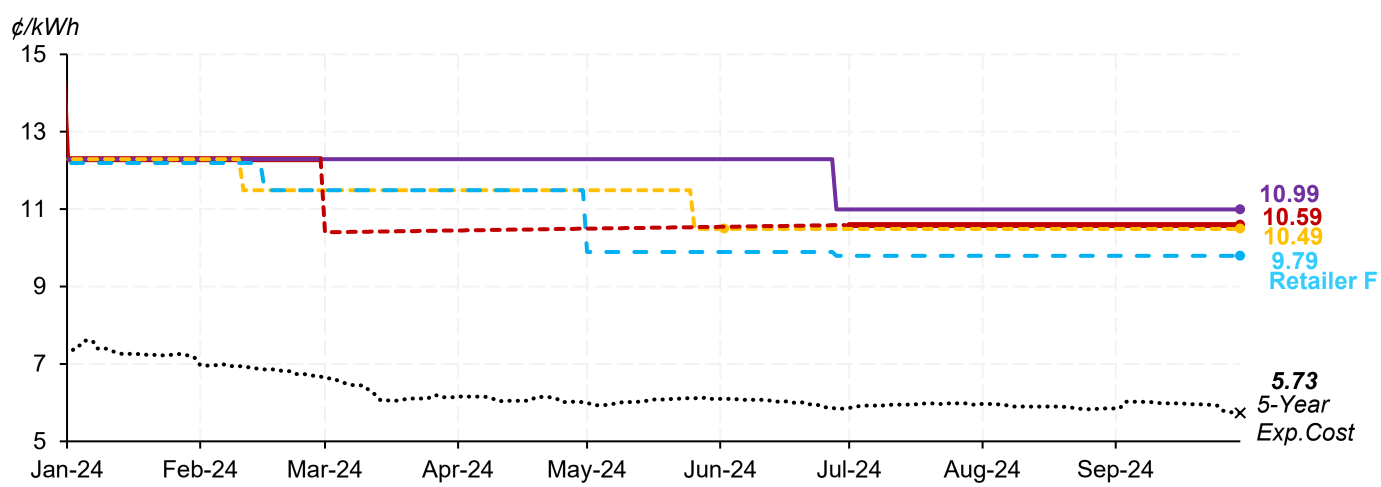
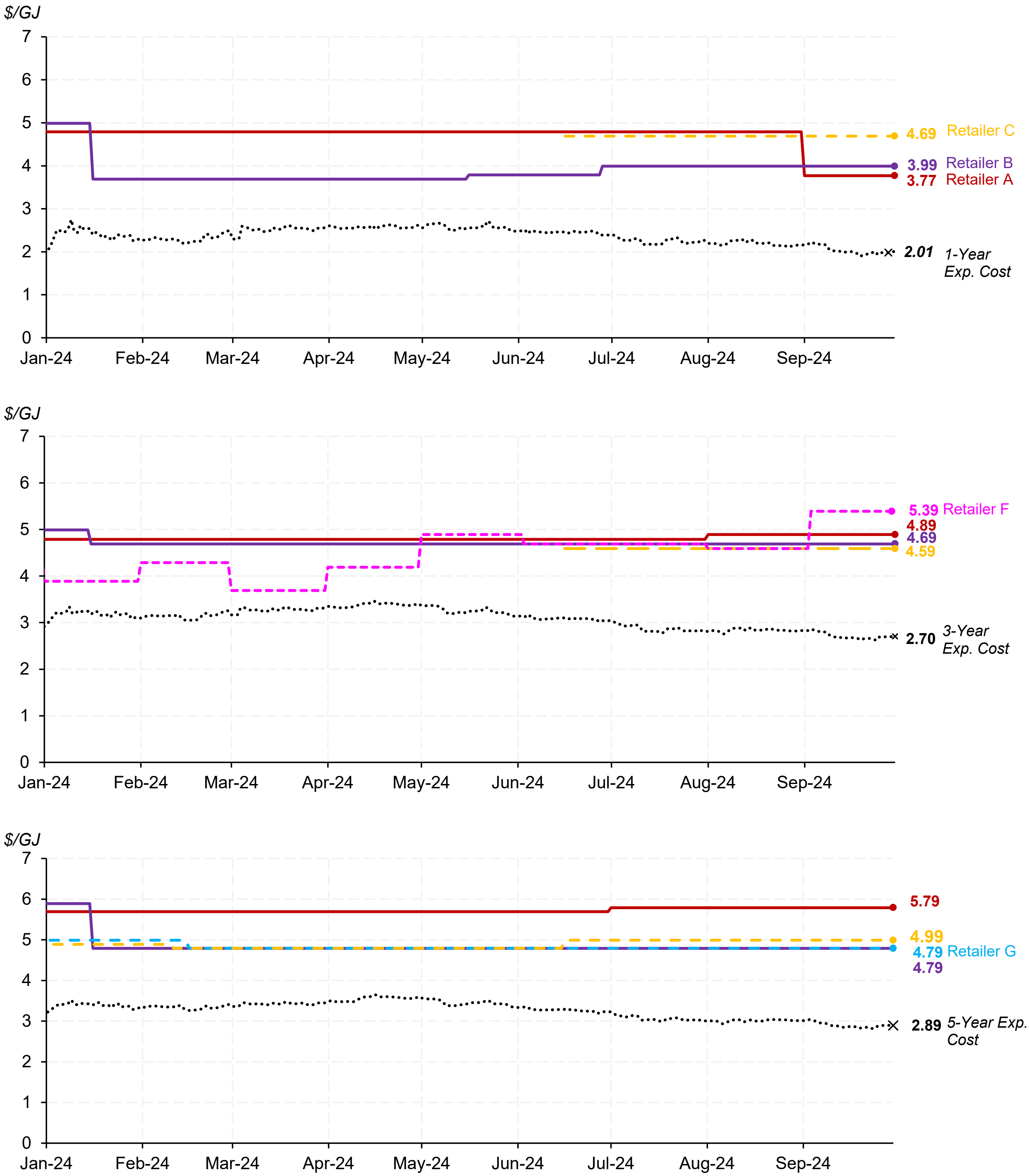


Figure 66: 1-, 3-, and 5-year fixed rate natural gas contract prices, residential customers, ATCO Gas South service area (January 1, 2024 to September 30, 2024)



5.4 Retail regulations and legislations

5.4.1 Rate of Last Resort (RoLR)

In September 2024, the *Regulated Rate Option* (AR 262/2005) was amended to become the *Rate of Last Resort Regulation* (AR 262/2005).[20] In accordance with this regulation, the Regulated Rate Option (RRO) will become the Rate of Last Resort (RoLR) on January 1, 2025. Presently, RRO rates change monthly and there is no limit to the change in rate between months. RoLR rates will be fixed for 2-year terms and will include a risk margin for the RoLR provider, as well as a 0.1 ¢/kWh consumer awareness surcharge. Additionally, RoLR rates between 2-year terms cannot change by more than 10%.

RoLR providers will continue to have their EPSPs approved by their regulatory authority. The RoLR rates in ENMAX, EPCOR, FortisAlberta, and ATCO Electric distribution service areas will be regulated by the Alberta Utilities Commission (AUC). Rural electrification association (REA) board of directors and municipal councils will continue as regulatory authorities for RoLR providers for REAs and wire-owning municipalities respectively. A rate-reopener provision will enable a regulatory authority to adjust a RoLR rate within a 2-year term if a RoLR provider experiences unacceptable financial performance. The rate re-opener will operate independently from the EPSP development process.

The RoLR energy rate line item must be displayed as the “Rate of Last Resort” on bills, with an additional statement on bills and Terms and Conditions. The Utilities Consumer Advocate (UCA) will contact RoLR consumers every 90 days to confirm they wish to stay on the RoLR. RoLR providers must share customer information with the UCA every two months to support this activity. The 0.1 ¢/kWh consumer awareness surcharge will fund this activity.

5.4.2 The role of the MSA in RoLR implementation

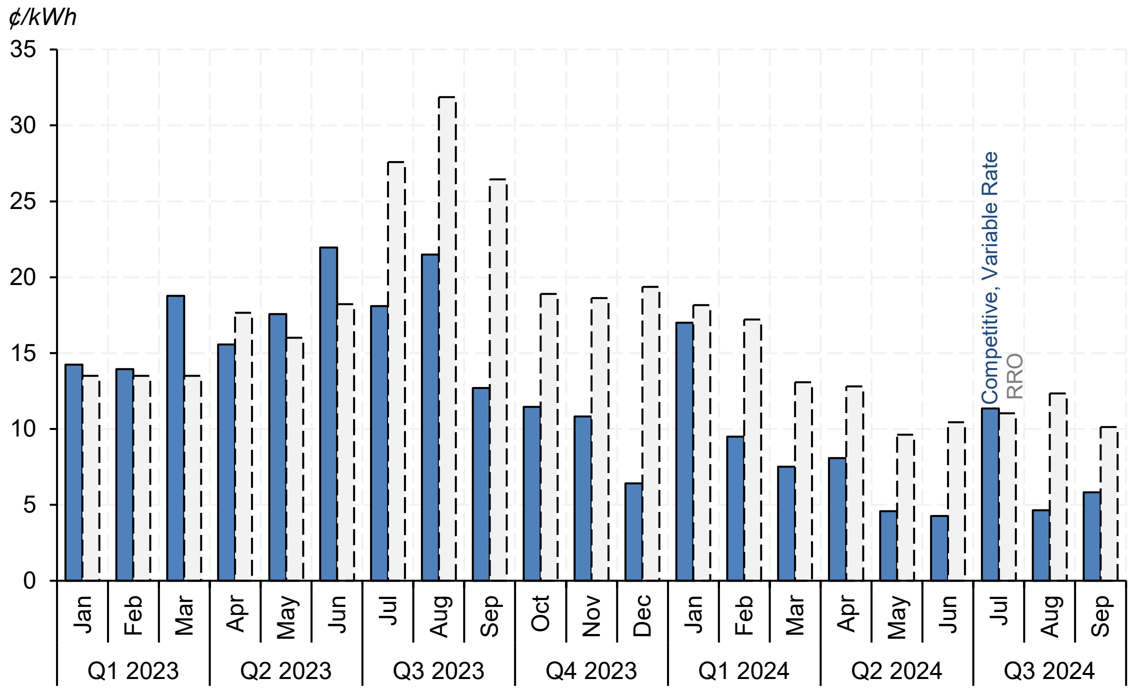
The MSA has two roles in EPSP development. Firstly, the MSA may provide advice to RoLR providers during the development of their EPSPs. Secondly, the MSA must provide a determination report on EPSPs submitted by RoLR providers (FEOC determination). This FEOC determination indicates whether the EPSP complies with the requirements for a fair, efficient, and openly competitive electricity market. RoLR providers must submit their EPSP to the MSA to receive a FEOC determination. RoLR providers must submit the MSA’s FEOC determinations to the regulatory authority when applying for approval of their EPSP. The MSA will also play a role in RoLR monitoring and the rate re-opening process. The MSA will be responsible for reporting on the financial performance of RoLR providers and recommending a rate re-opener if a RoLR provider’s financial performance falls outside of parameters set by the MSA.

[20] *Rate of Last Resort Regulation* (AR 262/2005)

5.5 Competitive variable retail rates

In August and September, competitive variable rates faced by residential electricity customers were lower, reflecting lower pool prices during those months. However, July experienced higher rates, driven by elevated pool prices relative to August and September. The high variables rates in July increased the quarterly average by 1.6 ¢/kWh compared to Q2 2024. Despite this, the average rate in Q3 2024 was 10.15 ¢/kWh lower than in Q3 2023. The variable rate of 11.35 ¢/kWh in July was on par with the default electricity rate (RRO) for the same month. However, in August and September, residential customers obtained a significant discount on competitive variable rates over the RRO (Figure 67).

Figure 67: Estimated competitive variable electricity rates vs. RRO, residential customers, ENMAX service area (Q1 2023 to Q3 2024)[21]



Competitive variable natural gas rates were higher than the default rates for natural gas (DRT) in all three months of Q3, continuing the trend observed in Q2 2024 (Figure 68). The variable gas rates were 116%, 69%, and 72% higher than the DRT in July, August, and September, respectively.

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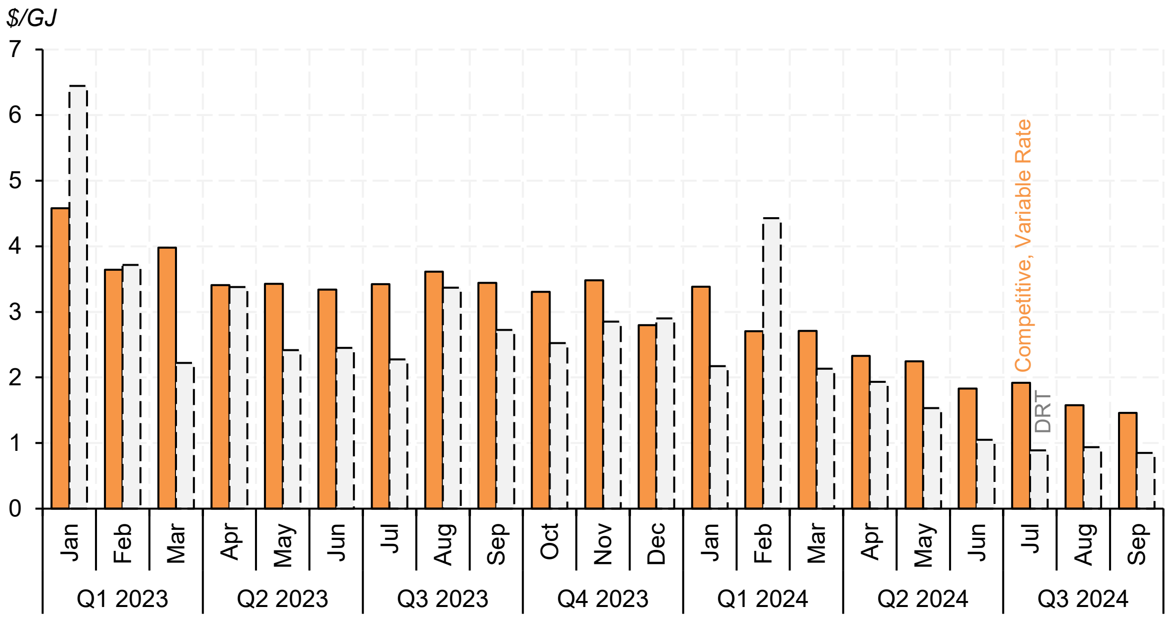
[21] Competitive variable electricity rates calculated as residential load-shaped pool price; includes a 1 ¢/kWh adder.

Figure 68: Estimated competitive variable natural gas rates vs. DRT, residential customers, ATCO Gas South service area (Q1 2023 to Q3 2024)



6 REGULATORY AND ENFORCEMENT MATTERS

6.1 Regulated Rate Option Stability Act investigation

On December 15, 2022, the *Regulated Rate Option Stability Act* (RROSA) was amended to impose a maximum regulated rate option (RRO) rate that could be charged in January, February, and March 2023. The amendments required RRO providers to calculate a deferral amount in each month based on the difference between the maximum rate and the RRO rate they would have otherwise charged during those months, and to establish a deferral account so they could track that deferral amount. That deferral account was to be established on or before December 23, 2022.

The MSA investigated an issue related to RROSA implementation at a Rural Electrification Association (REA) and found that the REA failed to establish the required deferral account, in contravention of section 4.2(1) of the RROSA. In addition, the MSA found the REA moved all its RRO customers to a retail tariff without their consent, contrary to section 5 of the *Code of Conduct Regulation,* to circumvent the requirement to establish a deferral account under the RROSA and thereby contravened section 2(l) of the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation). In accordance with MSA's Investigation Procedures, the MSA provided a summary of its findings to the REA for comment. The REA disputes the MSA's findings, and no entity with jurisdiction to do so has made a final determination as to whether the REA contravened the RROSA, FEOC Regulation, or other applicable enactment.

Section 26 of the *Rural Utilities Act* empowers the Minister of Affordability and Utilities (Minister) to direct the Director of Rural Electrification Associations to conduct an inquiry into the affairs of a rural utility.[22] When the MSA determines that a matter is within the jurisdiction of another body, the MSA is required to notify that body.[23] Accordingly, and based on information gathered in the course of its investigation, the MSA referred this matter to the Minister pursuant to section 45(1) of the *Alberta Utilities Commission Act*.

6.2 Rate of Last Resort engagement sessions

Following the announcement of the Rate of Last Resort (described in section 5.4), the MSA held stakeholder sessions for Rural Electrification Associations and municipalities on August 16,[24] September 3,[25] and October 7.[26] These sessions provided updates on the development of the Rate of Last Resort and provided a discussion forum for interested parties.

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[22] Rural Utilities Act RSA 2000 c R-21 [RUA], at ss. 1(c)(i), 1(e) and 26; Designation and Transfer of Responsibility Regulation AR 11/2023 s. 3(1)(o)

[23] Alberta Utilities Commission Act s. 45(1)

[24] MSA, Rate of Last Resort Implementation by Rural Electrification Associations and municipalities, August 16, 2024.

[25] MSA, Rate of Last Resort Implementation by Rural Electrification Associations and municipalities, September 3, 2024.

[26] MSA, Rate of Last Resort Implementation by Rural Electrification Associations and municipalities, October 7, 2024.

6.3 MSA report about Alberta electricity system events on January 13 and April 5

This MSA report[27] reviews and makes seven recommendations to the AESO and market participants related to two electricity system events that occurred on January 13 and April 5, 2024. While both events involved stressed grid conditions, the driving factors were very different. In addition, the MSA indicates it will place high priority on potential contraventions that hinder the AESO's ability to effectively discharge its responsibilities under the SCR.

6.4 Comments on Restructured Energy Market and Strategic Reserves

On September 9, the MSA provided comments on the AESO's initial approach to the Restructured Energy Market.[28] With the increasing complexity of the power system, market design evolution is required. In these comments, the MSA advocated for the implementation of a modern electricity market design that incorporates best practices and decades of experience in other jurisdictions. The MSA also cautioned that a bespoke market design may not be expected to persist and may undermine confidence in Alberta's electricity market.

On September 27, the MSA provided comments on the AESO's plans to contract for Strategic Reserves.[29] The AESO has described Strategic Reserves as an "insurance policy" responsive to "supply and demand uncertainties over the next five to seven years."[30] In its comments, the MSA identified a number of outstanding issues, including insufficient information to assess the AESO's proposal, AESO forecasts not supporting strategic reserves, the complexity and uncertainty of modelling asset retirements, and the blunting of incentive signals.

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[27] MSA, Alberta electricity system events on January 13 and April 5, 2024: MSA review and recommendations, August 6, 2024

[28] MSA, Comments re AESO's initial approach to the Restructured Energy Market technical design, September 9, 2024

[29] MSA, Comments re: AESO's Strategic Reserve proposal, September 27, 2024.

[30] AESO, Strategic Reserves to Address Supply Adequacy, September 5, 2024.

7 ISO RULES COMPLIANCE

The ISO rules promote orderly and predictable actions by market participants and facilitate the operation of the Alberta Interconnected Electric System (AIES). The MSA enforces 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 a contravention has occurred and determines 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 September 30, 2024, the MSA closed 357 ISO rules compliance matters, as reported in Table 19.[31] An additional 313 matters were carried forward to the next quarter. During this period 80 matters were addressed with NSPs, totalling $872,750 in financial penalties, with details provided in Table 20.

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

Table 19: ISO rules compliance outcomes from January 1 to September 30, 2024

ISO rule	Forbearance	Notice of specified penalty	No contravention
103.1	1	-	-
201.1	1	-	-
201.3	1	2	-
201.7	21	13	-
203.1	10	-	-
203.3	77	6	5
203.4	57	10	3
203.6	23	1	-
205.3	1	4	-
205.4	4	-	-
205.5	5	1	1
205.6	5	20	2
301.2	9	4	-
303.1	1	-	-
304.3	3	-	-
304.4	1	-	-
304.6	1	-	-
304.9	2	-	-
306.4	3	2	-
306.5	6	5	-
502.1	-	1	-
502.4	6	6	-
502.5	1	-	-
502.6	2	1	-
502.8	5	2	-
502.14	-	1	-
502.15	3	-	-
502.16	6	-	-
504.4	2	-	-
505.3	3	-	-
505.4	6	1	-
Total	266	80	11

Table 20: Specified penalties issued between January 1 and September 30, 2024 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)																	Total ($)	Matters
	201.3	201.7	203.3	203.4	203.6	205.3	205.5	205.6	301.2	306.4	306.5	502.1	502.4	502.6	502.8	505.4	502.14		
Air Liquide Canada Inc.		7,000				2,000												9,000	5
AltaGas Ltd.		500		6,500														7,000	3
ATCO DB Solar GP Services Ltd.		250																250	1
ATCO Electric Ltd.										250								250	1
BHE Canada Rattlesnake L.P.															500			500	1
Canadian Hydro Developers, Inc.						500	678,500										250	679,250	3
Capital Power (CBEC) L.P.						500												500	1
Castle Rock Ridge LP			500															500	1
Concord Monarch Partnership			500															500	1
Concord Stavely Partnership									500									500	1
Concord Vulcan Partnership									500						500			1,000	2
Conrad Solar Inc.									5,000									5,000	1
Cypress 2 Renewable Energy Centre Limited Partnership		13,750											1,250					15,000	4
Cypress Renewable Energy Centre Limited Partnership	250	13,750									500		1,250					15,750	6
Enel X Canada Ltd.								62,500										62,500	13
Forty Mile Granlea Wind GP Inc.		23,750		1,000						250								25,000	5
Ghost Pine Windfarm, LP				500														500	1
Grande Prairie Generation Inc.											500							500	1
Halkirk I Wind Project LP				250										250				500	2
Hays Solar LP			500															500	1
Heartland Generation Ltd.								250										250	1
Jenner 3 Limited Partnership			500															500	1
Kneehill Solar LP											500		500					1,000	2
Lanfine Wind 1 LP											500							500	1
MEG Energy Corp.				250														250	1
Michichi Solar LP											500		500					1,000	2
Morgan Stanley Capital Group Inc.					10,000													10,000	1

Table 21: Specified penalties issued between January 1 and September 30, 2024 for contraventions of the ISO rules (continued)

Market participant	Total specified penalty amounts by ISO rule ($)																	Total ($)	Matters
	201.3	201.7	203.3	203.4	203.6	205.3	205.5	205.6	301.2	306.4	306.5	502.1	502.4	502.6	502.8	505.4	502.14		
NAT-1 Limited Partnership				250														250	1
Oldman 2 Wind Farm Limited									500									500	1
Pincher Creek Limited Partnership			500															500	1
Signalta Resources Limited	250																	250	1
Syncrude Canada Ltd.																250		250	1
Taber Solar 1 Inc.			500															500	1
Tourmaline Oil Corp.		500																500	1
TransAlta Generation Partnership				750														750	1
Voltus Energy Canada Ltd.								30,000										30,000	6
Wheatland Wind Project LP				500														500	1
Whitecourt Power Ltd.		500																500	1
Windrise Wind LP												250						250	1
Total	500	60,000	3,000	10,000	10,000	3,000	678,500	92,750	6,500	500	2,500	250	3,500	250	1,000	250	250	872,750	80

The ISO rules listed in Table 19 and Table 20 fall into the following categories:

103 Administration
201 General (Markets)
203 Energy Market
205 Ancillary Services Market
301 General (System Reliability and Operations)
304 Routine Operations
306 Outages and Disturbances
502 Technical Requirements
504 Legal Owners of Transmission Facilities and Load Facilities
505 Legal Owners of Generating Facilities

8 ARS COMPLIANCE

The MSA assesses market participant compliance with Alberta Reliability Standards (ARS) and issues NSPs where appropriate.

The ARS ensure the various entities involved in grid operation have practices in place, including procedures, communications, coordination, training, and maintenance to support the reliability of the AIES.[32] 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 focuses on promoting awareness of obligations and a proactive compliance stance. The MSA's process, 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 only reports aggregated statistics regarding CIP ARS outcomes.

From January 1 to September 30, 2024, the MSA addressed 111 O&P ARS compliance matters (Table 22).[33] 25 O&P ARS matters were carried forward to the next quarter. During this period, 34 matters were addressed with NSPs, totalling $148,500 in financial penalties (Table 23). For the same period, the MSA addressed 81 CIP ARS compliance matters, as reported in Table 24, two matters were addressed with NSPs, totalling $7,500. 105 CIP ARS matters were carried forward to next quarter.

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[32] Entities subject to ARS include legal owners and operators of generators, transmission facilities, distribution systems, as well as the independent system operator.

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

Table 22: O&P ARS compliance outcomes from January 1 to September 30, 2024

Reliability standard	Forbearance	Notice of specified penalty	No contravention
COM-001	17	4	1
COM-002	2	-	-
EOP-005	-	1	-
EOP-008	6	8	-
EOP-011	1	1	-
FAC-008	12	1	-
IRO-008	1	-	-
PER-003	-	1	-
PER-005	-	3	-
PER-006	3	-	-
PRC-001	2	-	-
PRC-002	3	-	1
PRC-005	11	7	2
PRC-018	1	-	-
PRC-019	5	2	-
VAR-002	7	5	2
VAR-501	-	1	-
Total	71	34	6

Table 23: Specified penalties issued between January 1 and September 30, 2024 for contraventions of O&P ARS

Market participant	Total specified penalty amounts by ARS ($)											Total ($)	Matters
	COM-001	EOP-005	EOP-008	EOP-011	FAC-008	PER-003	PER-005	PRC-005	PRC-019	VAR-002	VAR-501-WECC		
City of Lethbridge					2,250			3,750				6,000	2
City of Medicine Hat	15,000		5,000									20,000	5
City of Red Deer								3,750				3,750	1
Forty Mile Granlea Wind GP Inc.										10,000		10,000	2
MEG Energy Corp.								2,500				2,500	1
Suncor Energy Inc.			32,500	12,500		12,500	14,500					72,000	12
Syncrude Canada Ltd.								5,500				5,500	3
TA Alberta Hydro LP		3,750						5,000	2,500	5,000	5,000	21,250	6
Windrise Wind LP										7,500		7,500	2
Total	15,000	3,750	37,500	12,500	2,250	12,500	14,500	20,500	2,500	22500	5,000	148,500	34

The ARS outcomes listed in Table 22 and Table 23 are contained within the following categories:

COM Communications
EOP Emergency Preparedness and Operations
FAC Facilities Design, Connections, and Maintenance
IRO Interconnection Reliability Operations and Coordination
PER Personnel Performance, Training, and Qualifications
PRC Protection and Control
VAR Voltage and Reactive

Table 24: CIP ARS compliance outcomes from January 1 to September 30, 2024

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-002	5	1	-
CIP-003	11	-	-
CIP-004	19	-	-
CIP-005	4	-	-
CIP-006	6	-	-
CIP-007	10	-	-
CIP-009	2	-	-
CIP-010	15	-	-
CIP-011	5	1	-
CIP-012	2	-	-
Total	79	2	-

The ARS outcomes listed in Table 24 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-009	Recovery Plans for BES Cyber Systems
CIP-010	Configuration Change Management and Vulnerability Assessments
CIP-011	Information Protection
CIP-012	Communications between Control Centres