MARKET SURVEILLANCE ADMINISTRATOR

Wholesale Market Report: Q3 2025

November 13, 2025

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

- **Increased gas capacity and solar generation drive decline in prices year-over-year:**

  The average pool price in Q3 was $51.29/MWh, which is a decline of 7% relative to Q3 2024 but is an increase of 27% compared to the Q2 average of $40.48/MWh. Pool prices were lower in Q3 this year due to more available gas capacity and higher solar generation (these fundamentals offset higher demand, a higher carbon price, and more exports).

  Pool prices were higher in Q3 compared to Q2 because of higher demand, less wind generation, and a planned BC/MATL intertie outage in late September.

- **AESO declares Energy Emergency Alert level 3 on September 8:**

  Between 18:54 and 20:04 on Monday, September 8, the AESO declared an Energy Emergency Alert level 3 (EEA3), indicating that there was insufficient supply to reliably meet demand. This is the first time the AESO has declared an Energy Emergency Alert since October 22, 2024, but no firm load was shed. Prior to reaching EEA3, at 17:39 the AESO dispatched 203 MW of load bids at the top of the merit order before directing 169 MW of contingency reserves to provide energy during EEA3, which left 346 MW of available contingency reserves remaining. The event was largely the result of low intermittent supply, gas generator outages, and reduced import capability. No assets were commercially offline as the AESO committed three gas-fired steam assets totalling 955 MW of capacity. Without these unit commitments the AESO would have needed to shed firm load. Gas generation assets provided 92% of supply during this event.

- **Prices at the offer cap on July 12:**

  On the evening of Saturday, July 12, the System Marginal Price cleared at the offer cap of $999.99/MWh between 20:31 and 21:00, between 21:27 and 22:40, and between 23:00 and 23:12. In total, the System Marginal Price was at the offer cap for 1 hour and 54 minutes although the supply cushion did not fall below 301 MW and the AESO did not declare an Energy Emergency Alert. The tight market conditions on July 12 were largely driven by gas generator outages, gas-fired steam assets being commercially offline, and low intermittent generation. The Keephills 2, Sheerness 1, and Sheerness 2 assets were commercially offline for this event, accounting for 1,200 MW of capacity. These assets were not committed by the AESO for this event partly because a drop in wind generation materialized sooner than the 24-hour forecast had predicted. Further, the tight market conditions were not predicted by importers and Alberta was a slight exporter of power despite prices in Alberta being well above prices in Mid-Columbia and California.

- **Prices at the offer cap on September 16:**

  Between 18:33 and 19:08 on Tuesday, September 16 the System Marginal Price cleared at the offer cap of $999.99/MWh. During this period the supply cushion did not fall below 203 MW and no Energy Emergency Alert was declared by the AESO. The high prices in this event were driven by low intermittent supply, gas generator outages, and reduced import capability. As with the other events, prices were elevated around the net demand peak in the evening when solar generation had declined but demand remained high. With low wind generation, natural gas assets met the majority of demand during this event at 90%. There were no assets commercially offline on long lead time as the AESO committed the Battle River 4 and Sheerness 2 assets, although the start-up of Sheerness 2 was delayed by around 3 hours.

- **Lowest daily average pool price on September 21:**

  On Sunday, September 21, the daily average pool price settled at $0.75/MWh the lowest ever, undercutting the prior record of $0.79/MWh set on August 24, 2024. The System Marginal Price was at the price floor of $0/MWh for 73% of the day. The lower prices on September 21 were the result of high wind generation, low demand levels, and a planned outage on the BC/MATL intertie which meant that exports were unable to flow.

- **The AESO issued 40 unit commitment directives in the quarter:**

  The secondary offer price limit was not triggered in Q3, although net revenues in September reached 86% of the threshold. The AESO issued 40 unit commitment directives in the quarter. These unit commitment directives increased supply cushion during some tight hours, and the MSA estimates they reduced the average pool price for Q3 by $9.92/MWh or 19%.

- **Transmission constraint trends in Q3:**

  The total volume of constrained intermittent generation reached 268 GWh in Q3, a 114% increase from Q3 2024. At least 1 MW of wind and solar generation was constrained down in 54% of hours in the quarter. The constrained and unconstrained SMP differed by $1/MWh or more in 20% of hours in Q3. On September 3 in HE 20 the difference between the constrained and unconstrained SMP reached $893/MWh, the highest in the quarter.

- **New entry into regulating reserves:**

  The AESO procured an additional 50 MW of regulating reserves for the on-peak and off-peak periods during the BC/MATL intertie outage in late September to deal with more routine variation in system frequency. This additional volume put upward pressure on the prices for operating reserves. However, the received price for regulating reserves declined from $80/MW in Q2 to $72/MW in Q3 despite the higher demand and the higher pool prices in Q3. The lower received price for regulating reserves was largely driven by the entry of a small hydro and battery asset, Raymond Reservoir, in early August.

- **Forward market liquidity continued to be low:**

  Liquidity in the forward market for Alberta power continued to be low in Q3. Total trade volumes in the quarter were 4.51 TWh which is a 29% decline compared to the previous quarter and a 27% decline year-over-year. For annual contracts, the largest price moves occurred on August 5 when prices increased due to buying pressure and data centre developments. However, prices declined on subsequent days before remaining relatively flat for the duration of the quarter. At the end of Q3, Cal 26 was priced at $50.65/MWh, Cal 27 was priced at $61.00/MWh, and Cal 28 was priced at $78.00/MWh.

- **MSA public database to include data on market power and carbon emissions:**

  The MSA will be launching a public reporting site, data.albertamsa.ca, in mid-November.

1 THE POWER POOL

1.1 Quarterly summary

The average pool price in Q3 was $51.29/MWh, which is a 7% decrease relative to Q3 2024 but is a 27% increase compared to Q2. The lower pool prices year-over-year were driven by more available gas generation capacity and increased solar supply as these fundamentals offset higher demand, a higher carbon price, and more exports (Table 1). The higher pool prices in Q3 relative to Q2 were caused by higher demand, less wind generation, and a planned BC/MATL intertie outage in late September.

Table 1: Summary market statistics for Q3 2024 and Q3 2025

		2024	2025	Change
Pool price (Avg $/MWh)	Jul	$88.62	$31.19	-65%
	Aug	$34.26	$50.35	47%
	Sep	$42.80	$73.05	71%
	Q3	**$55.36**	**$51.29**	**-7%**
Demand (AIL) (Avg MW)	Jul	10,408	10,010	-4%
	Aug	9,945	10,194	3%
	Sep	9,436	9,989	6%
	Q3	**9,935**	**10,065**	**1%**
Gas price AB-NIT (2A) (Avg $/GJ)	Jul	$0.92	$0.75	-19%
	Aug	$0.58	$0.80	39%
	Sep	$0.46	$0.33	-28%
	Q3	**$0.65**	**$0.63**	**-4%**
Wind gen. (Avg MW)	Jul	1,040	1,128	8%
	Aug	1,114	1,115	0%
	Sep	1,367	1,346	-2%
	Q3	**1,172**	**1,195**	**2%**
Solar gen. (Avg MW during peak hours)	Jul	800	865	8%
	Aug	706	895	27%
	Sep	575	717	25%
	Q3	**695**	**826**	**19%**
Net imports (+) Net exports (-) (Avg MW)	Jul	-185	-505	173%
	Aug	-418	-367	-12%
	Sep	-233	-179	-23%
	Q3	**-279**	**-352**	**26%**
Available thermal capacity (Avg MW)	Jul	9,935	10,410	5%
	Aug	10,169	10,262	1%
	Sep	9,575	9,469	-1%
	Q3	**9,896**	**10,053**	**2%**

The lowest monthly price in Q3 occurred in July when pool prices averaged $31.19/MWh, a 65% decrease year-over-year and the lowest price for July since 2017. The lower prices in July were largely driven by mild weather conditions and high availability of gas generation.

In contrast, prices were higher in September which averaged $73.05/MWh, the highest monthly price since July 2024. Prices in September were increased by higher demand, reduced import capability, and planned generator outages.

Average demand was 6% higher in September this year as average temperatures increased by 1.4°C (Table 2). Similarly, higher temperatures in August this year led demand to increase by 3%.

In early September the ability of importers to supply power from BC and Montana was reduced because of a transmission outage on line 5L92. This increased pool price volatility in certain hours, particularly when intermittent generation in Alberta was low.

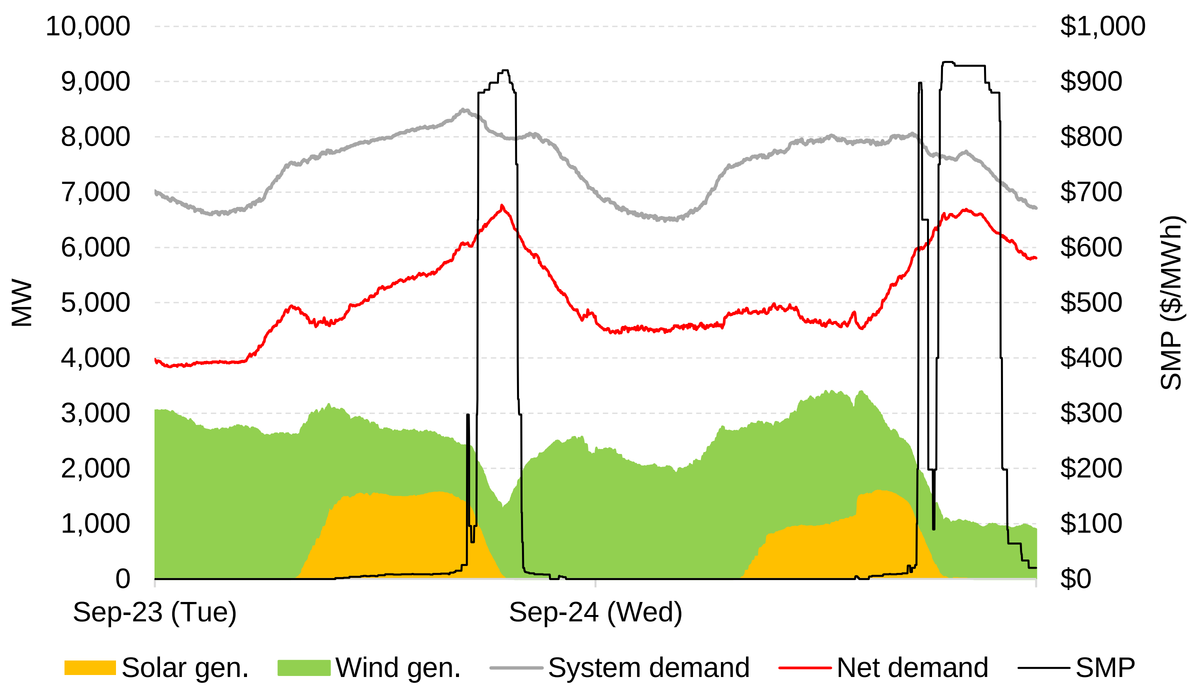
On September 8 the reduced import capability combined with low intermittent supply and some gas generator outages to cause the AESO to declare an EEA3, indicating that there was insufficient supply to reliably meet demand. In this instance, the AESO dispatched load bids at the top of the merit order and then directed some of its contingency reserves to help meet prevailing demand. This event is discussed further in section 1.2.

Table 2: Average temperature (°C) by month across Calgary, Edmonton, and Fort McMurray (Q3 2024 and 2025)

	2024	2025	Difference
Jul	21.0	17.2	-3.8
Aug	17.6	18.3	0.7
Sep	14.1	15.5	1.4

In the back half of September, pool price volatility was increased as the BC/MATL intertie was taken offline for a planned outage from September 19 to 28. This outage meant exports were not available when intermittent generation in Alberta was high, and imports were not available when intermittent generation in Alberta was low. Consequently, pool prices on some days illustrated a bimodal distribution wherein prices were at the floor of $0/MWh for extended periods during the day before increasing above $900/MWh for a few hours during the net demand peak in the evening. For example, Figure 1 illustrates the SMP and net demand for September 23 and 24.

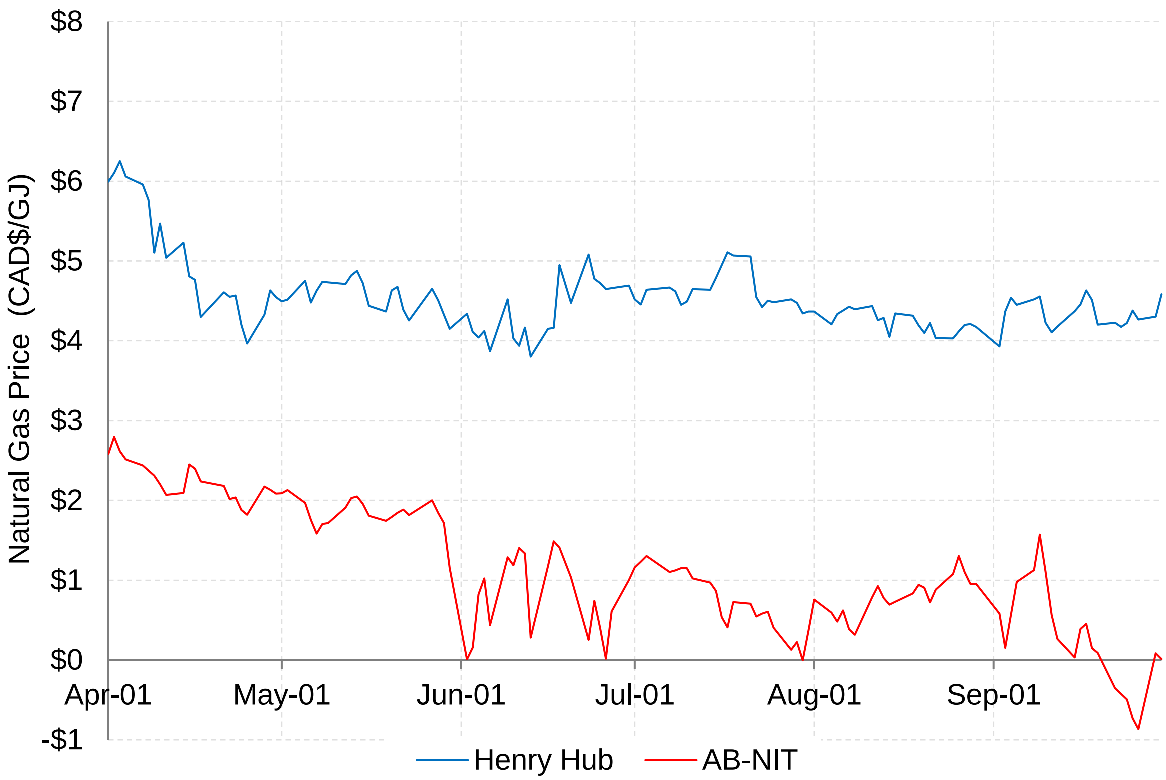
Figure 1: SMP and net demand (September 23 and 24)



In addition to increasing pool price volatility, the outage on BC/MATL also removed the frequency response Alberta gets from the Western Interconnection. As a result, the AESO procured more regulating reserves during the BC/MATL outage to deal with higher routine deviations in system frequency. In addition, the AESO procured more Fast Frequency Response (FFR) to help manage contingency events during the BC/MATL outage, as is outlined in section 1.2.

Natural gas prices in Alberta continued to be low in Q3. On average, sameday natural gas prices at the AB-NIT hub were $0.63/GJ across the quarter. Despite the commissioning of LNG Canada earlier in the year, natural gas production remains high, storage levels are elevated, and there have been pipeline constraints on shipping natural gas out of Alberta. As a result, natural gas prices in Alberta have been trading at a material discount to prices at Henry Hub (Figure 2). In late September, natural gas prices in Alberta were negative on some days, reaching a low of negative $0.87/GJ on September 26. The low natural gas prices mean low input costs for Alberta gas generators, with an average spark spread of $46.57/MWh over the quarter (assuming a heat rate of 7.5 GJ/MWh).

Figure 2: Sameday natural gas prices (April 1 to September 30)



Solar generation increased by 19% year-over-year and was a major factor in the lower prices in Q3 this year. This higher solar supply was a function of increased capacity and a higher capacity factor. Solar capacity in Alberta increased by 187 MW year-over-year; from 1,659 MW at the end of Q3 2024 to 1,846 MW at the end of Q3, which largely reflects the addition of the Big Sky Solar asset (140 MW) late last year.

Different generation assets in Alberta will receive different average prices depending upon how much they produce when pool prices are high or low. Dispatchable generators that can increase output when prices are high and reduce output when prices are low will receive a higher average price for their supply. Table 3 below provides received prices for different generator types in Q3.

Table 3: Received price by generator fuel type (Q3)

Generator type	Average received price ($/MWh)	Premium to avg. pool price
Simple cycle	$115.47	125%
Gas-fired steam	$70.57	38%
Hydro	$64.08	25%
Combined cycle	$53.57	4%
Avg. pool price	***$51.29***	***0%***
Cogeneration	$49.59	-3%
Solar	$43.53	-15%
Wind	$26.41	-49%

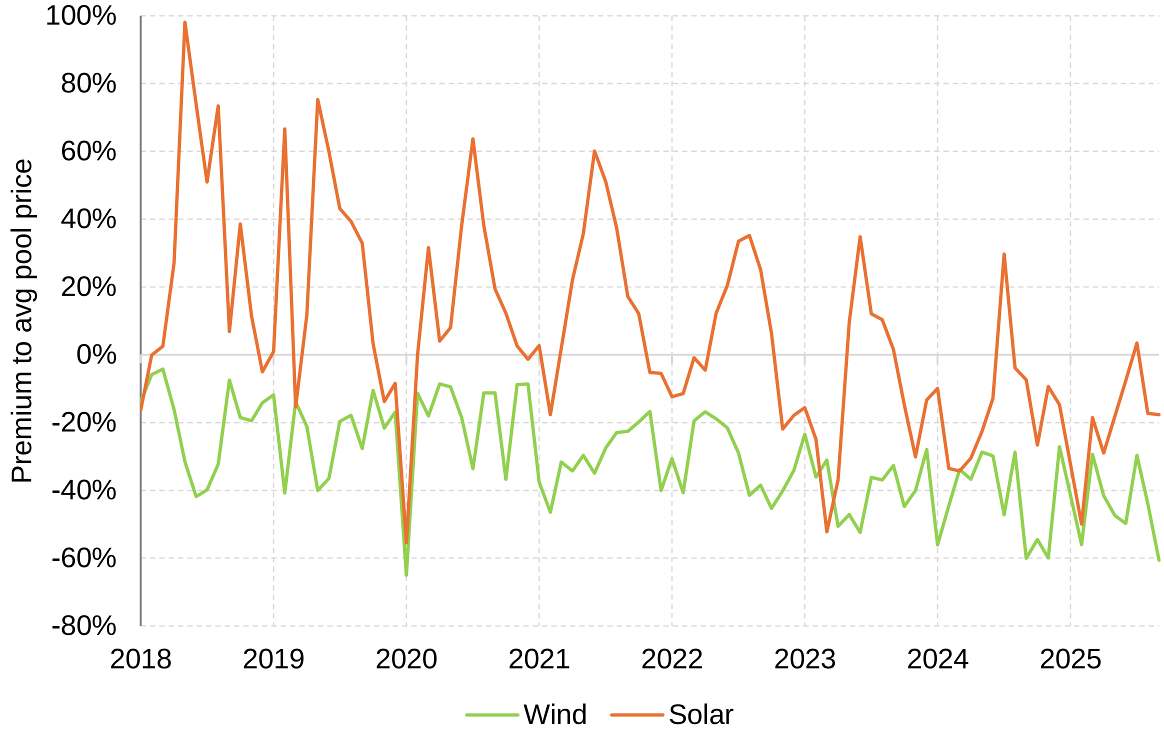
Simple cycle assets received the highest price in Q3 with an average received price of $115/MWh, which is a 125% premium to the average pool price. Gas-fired steam and hydro assets also used their ability to dispatch to obtain a higher received price. Combined cycle and cogeneration assets both had received prices that were comparable to the average pool price, which reflects their consistent supply over the quarter.

Solar assets had an average received price of $43.53/MWh in Q3, a 15% discount to the average pool price. Solar assets received a discount to the average pool price because the output of solar generators across Alberta is highly correlated. When solar generation is high at one solar farm it is likely to be high at other solar assets as well. This increased supply puts downward pressure on pool prices and lowers the received price for solar generators, even though they are generally producing during hours of higher demand.

For wind assets, the received price in Q3 was $26.41/MWh which is a 49% discount to the average pool price. As with solar assets, the generation across most wind farms in Alberta is highly correlated and when wind output is high, pool prices are generally low. In addition, wind generation is often higher on days of mild weather and overnight when demand is lower, which puts further downward pressure on the received price.

The received price of wind generation has been at a discount to average pool prices for many years (Figure 3). However, it is only in recent years, as more solar capacity has been added, that the received price of solar generation has cleared at a discount to the average pool price. So far in 2025, only July has seen the received price of solar generation clear at a slight premium; $32.27/MWh compared to an average pool price of $31.19/MWh.

Figure 3: Premium of wind and solar received prices to the average pool price (January 2018 to September 2025)



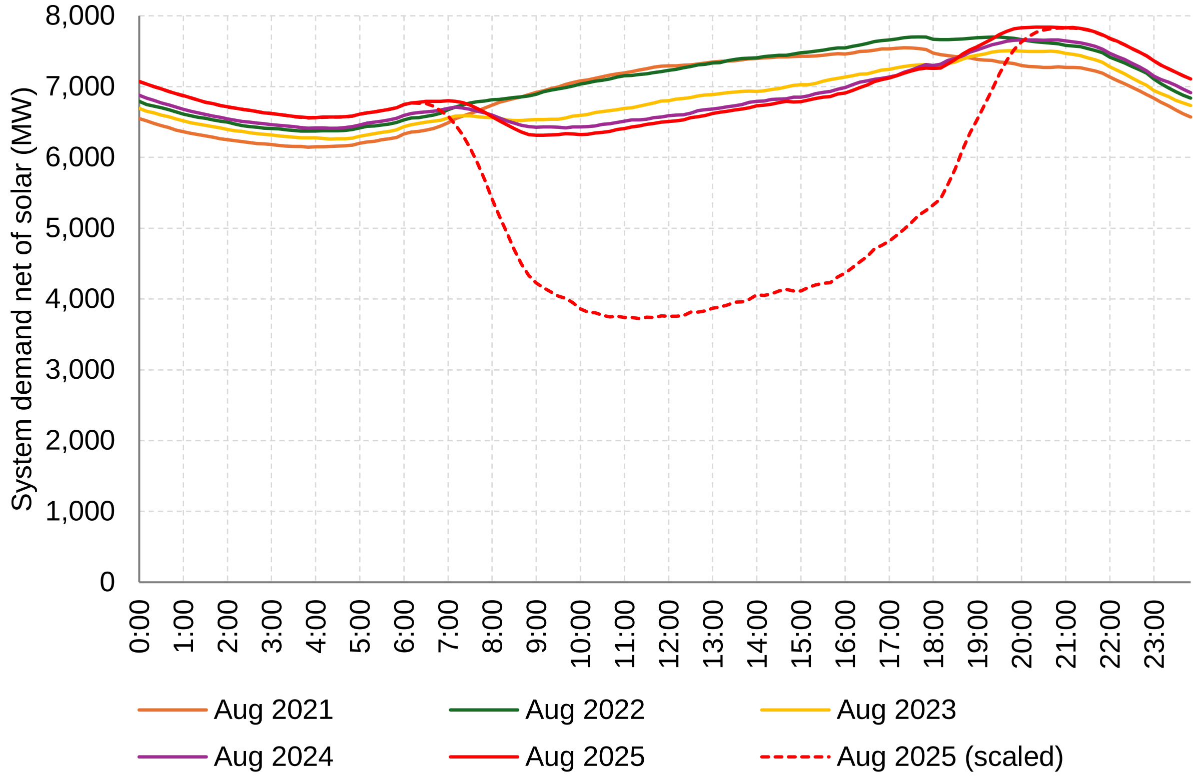
The addition of more solar capacity in recent years has reduced the amount of system demand left to be served during daylight hours (Figure 4). In August, the average amount of system demand left to be served after netting out solar generation was lower at 09:00 than at 04:00 by 450 MW.

Further to this, more solar capacity is scheduled to be developed. The AESO's November *Long Term Adequacy Metrics* note that 3,405 MW of solar capacity is under development and has met the project inclusion criteria. These additions would take total solar capacity in Alberta to 5,255 MW, or almost three times current levels.

Scaling current solar generation up to account for this additional capacity leads to a material impact on the daily profile of system demand net of solar generation (Figure 4). As shown by the August 2025 scaled line, the development of all this solar capacity would cause the daily profile to hit a low of under 4,000 MW at around 11:00, whereas the current low in August was around 6,300 MW at 09:00.

However, the additional solar capacity will not offset system demand at the net demand peak in the evening, which occurs when the sun sets. As a result, the addition of further solar capacity will likely lead to a more bimodal distribution of pool prices as we are currently starting to observe (see Figure 1 for example).

Figure 4: Average system demand net of solar generation by time of day (August 2021 to 2025)



1.2 Market outcomes and events

In Q3, prices continued to spend a large amount of time at the price floor. Over the quarter, the SMP cleared at $0/MWh 8% of the time although this is down from 10.3% in Q2 and 9.7% in Q3 2024 (Figure 5). As discussed in previous reports, prices have been clearing at the floor more often since mid-2024 because of increased intermittent supply and higher must-run gas generation.

The SMP also cleared at the offer cap during three events in Q3: on July 12, September 8, and September 16. These events all occurred around the net demand peak in the evening hours and are discussed in detail below. In total the SMP cleared at the offer cap for 5 hours and 53 minutes or 0.3% of the time in the quarter.

The distribution of prices in Q3 was comparable to Q3 2024 (Table 4). In Q3, prices in the top 10% of minutes averaged $349.23/MWh and contributed 68% to the quarterly average price. At the other end of the distribution, prices in the bottom 50% of minutes averaged $9.36/MWh and contributed 9% to the average price.

These figures illustrate that prices are low most of the time and it is only in a small number of hours that higher prices occur. However, these higher prices are a major driver of average prices. In Q2 the average price was lower at $40.48/MWh largely because fewer high-priced events occurred; the average price in the top 10% of minutes was $216.30/MWh in Q2 which is $132.92/MWh less than in Q3 (Table 4).

Figure 5: The percent of time the SMP was at the price floor and cap (Q1 2018 to Q3 2025)

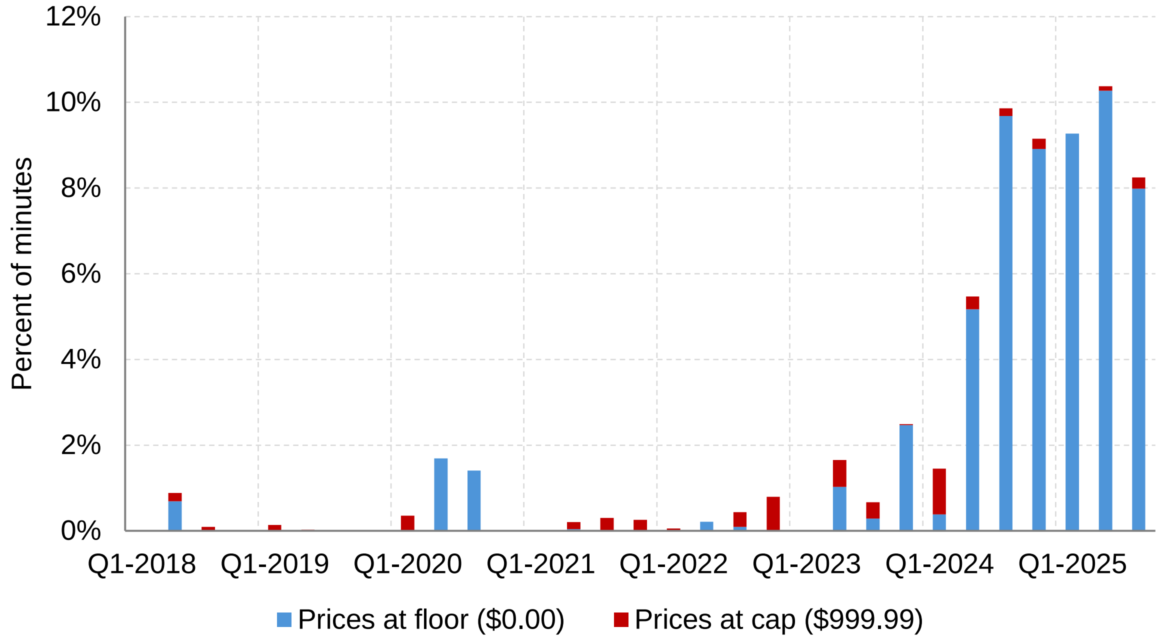


Table 4: Distribution of SMPs (Q3, Q2, and Q3 2024)

	Q3 2025 (Avg. $51.29)		**Q2 2025 (Avg. $40.48)**		**Q3 2024 (Avg. $55.36)**	
Percentile	**Avg price**	**Contribution to avg.**	**Avg price**	**Contribution to avg.**	**Avg price**	**Contribution to avg.**
Top 10%	$349.23	68%	$216.30	53%	$349.48	63%
10 to 50%	$29.22	23%	$33.43	33%	$36.18	26%
Bottom 50%	$9.36	9%	$10.96	14%	$11.89	11%

1.2.1 September 8 EEA3 event

On the evening of Monday, September 8, the AESO declared an EEA3 event for over an hour, between 18:54 and 20:04, indicating there was not enough generation supply to reliably meet demand. This is the first EEA event since October 22, 2024, and was largely the result of low intermittent supply, gas generator outages, and reduced import capability.

During this event, the AESO directed up to 169 MW of contingency reserves to provide energy to help meet demand. This left the AESO with 346 MW of available contingency reserves remaining. No firm load was shed during the event and the SMP did not reach $1,000/MWh.

The reduced supply on September 8 increased prices, with the daily average settling at $409.93/MWh, the highest since April 5, 2024. For three and a half hours between 16:52 and 20:16 the SMP cleared at the offer cap of $999.99/MWh, indicating very tight market conditions.

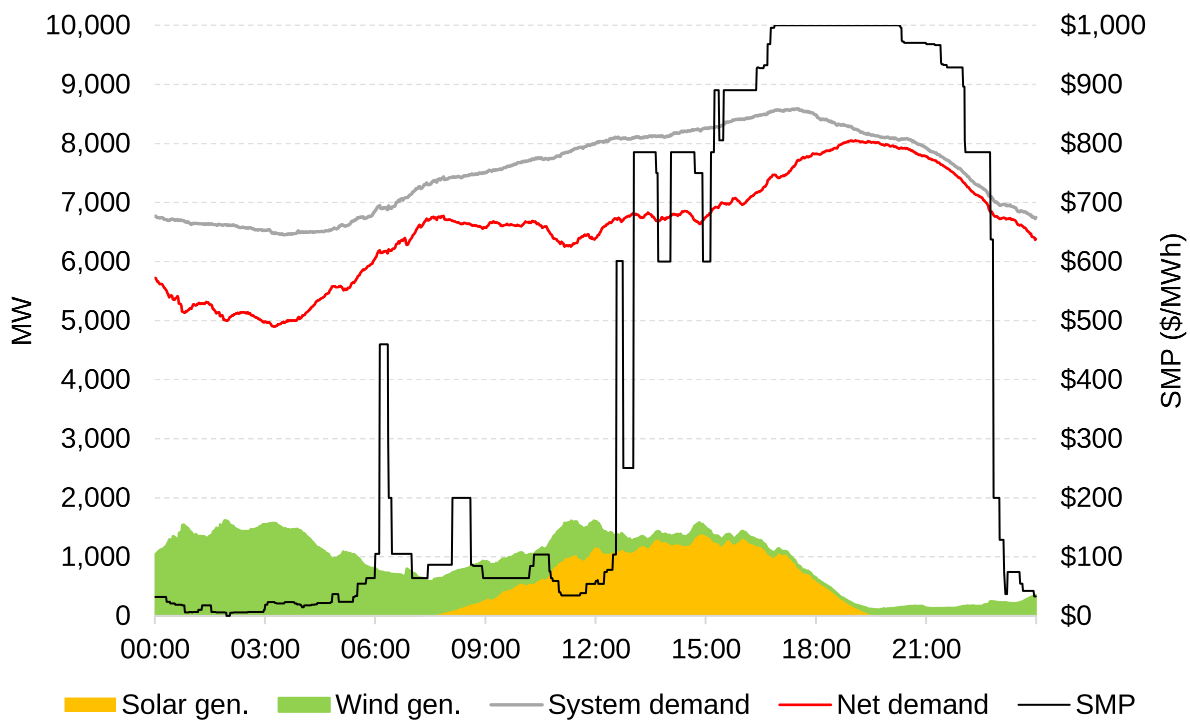
For 2 hours and 37 minutes, between 17:39 and 20:16, the SMP was set by MWAD, a load asset bid at the offer cap at the top of the merit order. In total, 203 MW of load bids were dispatched during this event (Table 5). In July three load assets started to bid into the energy merit order at the offer price cap. In response to dispatches these assets reduce their consumption, which is equivalent to generation increasing supply. The participation of load assets in the energy market is not something that has occurred historically.

Table 5: Load assets bidding into the energy market

Asset ID	Capacity (MW)	Start date
ANCD	83	July 1, 2025
MWFD	65	July 24, 2025
MWAD	55	July 24, 2025

Wind generation during this event was low (Figure 6). During the EEA3 declaration period, wind generation averaged only 87 MW compared to total wind capacity of 5,676 MW. Solar generation on September 8 peaked at 1,400 MW around 15:00 but was lower during the EEA3 event, falling from 200 MW at 18:54 to 0 MW by 19:45.

Figure 6: SMP and net demand (September 8)



On September 8, prevailing temperatures were above normal with peaks of 24°C in Calgary (6°C above normal), 27°C in Edmonton (8°C above normal), and 19°C in Fort McMurray (3°C above normal). As a result, Alberta Internal Load (AIL) reached a high of 11,055 MW in HE 18. For context, this is around 1,200 MW below the summer demand record of 12,221 MW (set on July 22, 2024) but is higher than normal demand for September. Therefore, the EEA3 event on September 8 was not strictly driven by high demand levels.

On the supply side, there were several large generator outages during this event (Table 6). As demand is typically lower in September than during summer months, scheduled generator outages are more likely to occur in September.

There were a number of generators offline at Base Plant on September 8, so a large amount of capacity was on outage at this asset. However, this was the case for much of the quarter as Suncor continued to integrate new generation units at the site.

The Genesee Repower 2 asset was offline on a delayed forced outage on September 8 to repair the steam turbine. This outage was scheduled at 00:43 on September 7 with the asset coming offline in HE 24 of September 7 and returning to the market in HE 15 of September 9.

There were no assets commercially offline on long lead time for the EEA3 event on September 8 as the AESO committed Sheerness 2, Battle River 4, and Sheerness 1 to come online and provide power (Table 7).

Table 6: Generator outages greater than 100 MW (HE 20 of September 8)

Asset name	Asset ID	Fuel type	Capacity on outage (MW)
Base Plant	SCR1	Cogeneration	689
Genesee Repower 2	GNR2	Combined cycle	466
Mackay River	MKRC	Cogeneration	207
Bow River	BOW1	Hydro	194
Firebag	SCR6	Cogeneration	167
Syncrude	SCL1	Cogeneration	165
Dow Hydrocarbon	DOWG	Cogeneration	146
Nexen Inc #2	NX02	Cogeneration	135
Battle River 5	BR5	Gas-fired steam	105
Shepard	EGC1	Combined cycle	102
MEG1 Christina Lake	MEG1	Cogeneration	102
Cloverbar #2	ENC2	Simple cycle	101

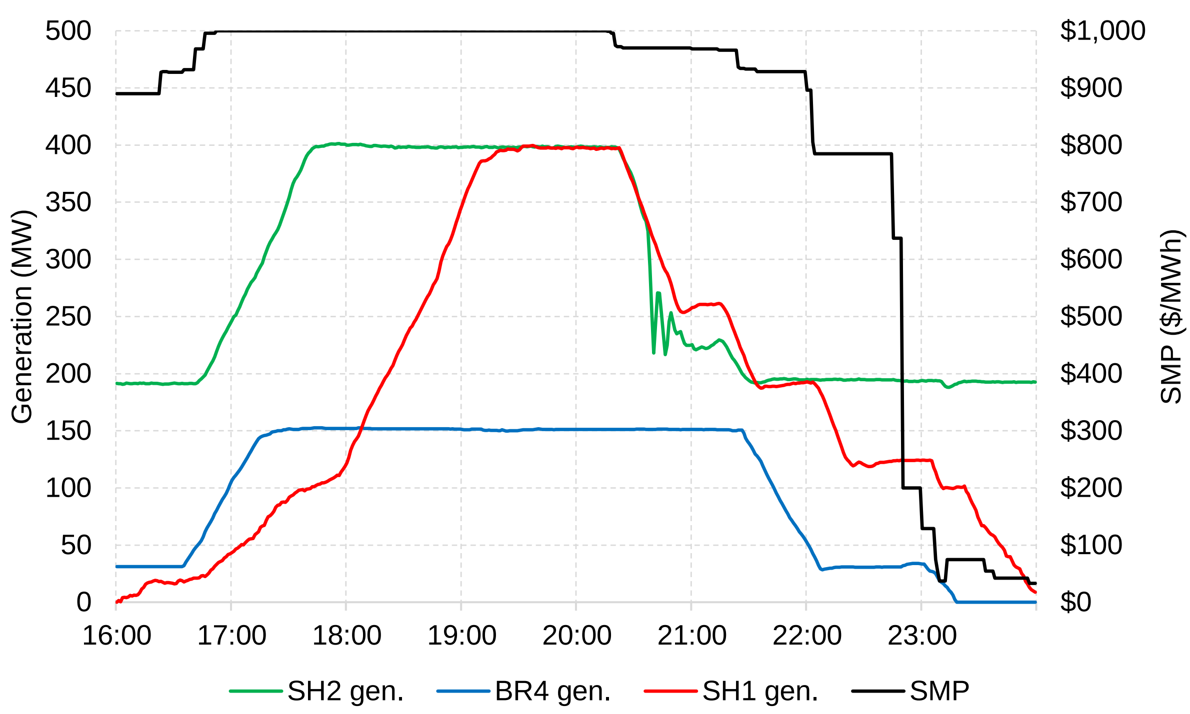
Table 7: Unit commitment directives for September 8

Asset ID	Capacity (MW)	Issued time	Begin time	Operation start time	Operation end time
SH2	400	09/07/2025 07:25:37	09/07/2025 08:00:00	09/08/2025 08:00:00	09/08/2025 23:00:00
BR4	155	09/07/2025 09:50:15	09/07/2025 10:00:00	09/08/2025 10:00:00	09/08/2025 23:00:00
SH1	400	09/07/2025 15:26:29	09/07/2025 16:00:00	09/08/2025 16:00:00	09/08/2025 22:00:00
SH1	400	09/08/2025 21:51:09	09/08/2025 22:00:00	09/08/2025 22:00:00	09/08/2025 23:00:00

Figure 7 illustrates the generation of these committed assets alongside the SMP on the evening of September 8. In combination, the three assets provided up to 950 MW during the event, a meaningful increase in supply. Without these unit commitments, the AESO would have shed firm load on the evening of September 8 to balance supply and demand.

Import constraints were an important factor in reducing supply for this event. On the morning of August 28, a transmission outage on line 5L92 was scheduled to begin in HE 08 of September 8. This outage went ahead as scheduled and lowered available import capability on BC/MATL until the evening of September 18. During the EEA3 event on September 8, import capability on BC/MATL was derated to around 80 MW whereas it would normally be available to supply around 400 MW.

Figure 7: SMP and the generation of SH2, BR4, and SH1 (September 8)



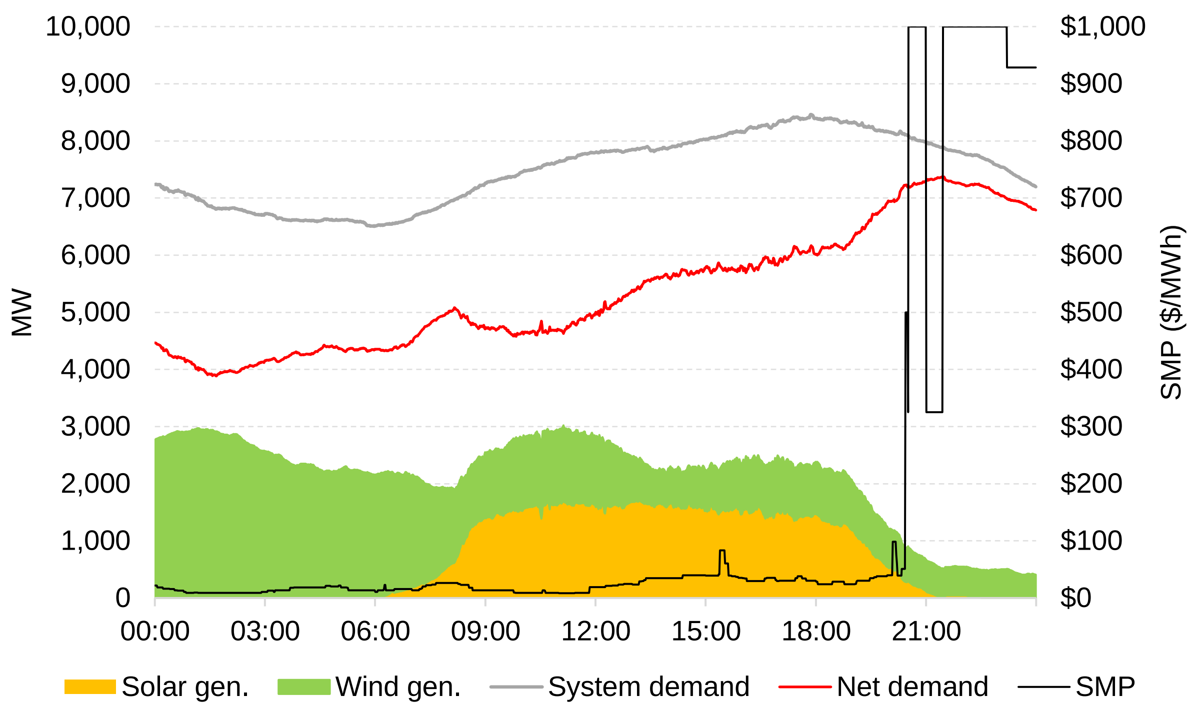
1.2.2 July 12 prices at the offer cap

On the evening of Saturday, July 12 the SMP cleared at the offer cap of $999.99/MWh between 20:31 and 21:00, between 21:27 and 22:40, and between 23:00 and 23:12. In total the SMP was at the offer cap for 1 hour and 54 minutes. The tight market conditions on July 12 were largely driven by gas generator outages, gas generators being commercially offline, and low intermittent generation.

Despite the high prices, the supply cushion did not fall to 0 MW in this event as there was still capacity available for dispatch at the top of the energy market merit order. The AESO did not declare an EEA for this event and contingency reserves were not directed to provide energy.

Intermittent generation was relatively low and declining during this event (Figure 8). Wind generation declined from 850 MW at 19:00 to 500 MW at 21:30, and while the SMP cleared at the offer cap, wind generation averaged 515 MW. In terms of solar generation, supply fell from 280 MW to 0 MW while the SMP was at the offer cap, compared to a peak of 1,700 MW earlier in the day.

Figure 8: SMP and net demand (July 12)



Demand on July 12 was moderate as AIL peaked at 10,990 MW in HE 18 with temperature highs of 29°C in Calgary, 26°C in Edmonton, and 22°C in Fort McMurray. Further to this, AIL had fallen to 10,207 MW by HE 23 when pool price settled at the offer cap. Therefore, high demand was not a major driver of the tight market conditions in this event.

The main generation outages on July 12 were at Genesee Repower 2 and Joffre. The Genesee Repower 2 asset (466 MW) was taken offline beginning in HE 23 of July 11 through to HE 23 of July 13 for a filter replacement. The Joffre asset (474 MW) was derated by around 200 MW because the steam turbine was unavailable from July 12 HE 04 to July 16 HE 17. Further to this, the Base Plant asset (856 MW) was operating around 500 MW below its maximum capacity as commissioning activities at the site continued.

In addition to these outages there was 1,200 MW of gas-fired steam capacity that was commercially offline on long lead time for this event. Specifically, Keephills 2 (395 MW), Sheerness 1 (400 MW), and Sheerness 2 (400 MW) were all commercially offline when the SMP cleared at the offer cap on July 12.

Table 8 provides the anticipated supply cushions 24 hours out for the evening hours of July 12. As shown, the anticipated supply cushions were all above the 932 MW threshold and therefore neither of the Sheerness assets were committed by the AESO at this time.

Table 8: Actual and anticipated supply cushion (HE 20 to 24 of July 12)

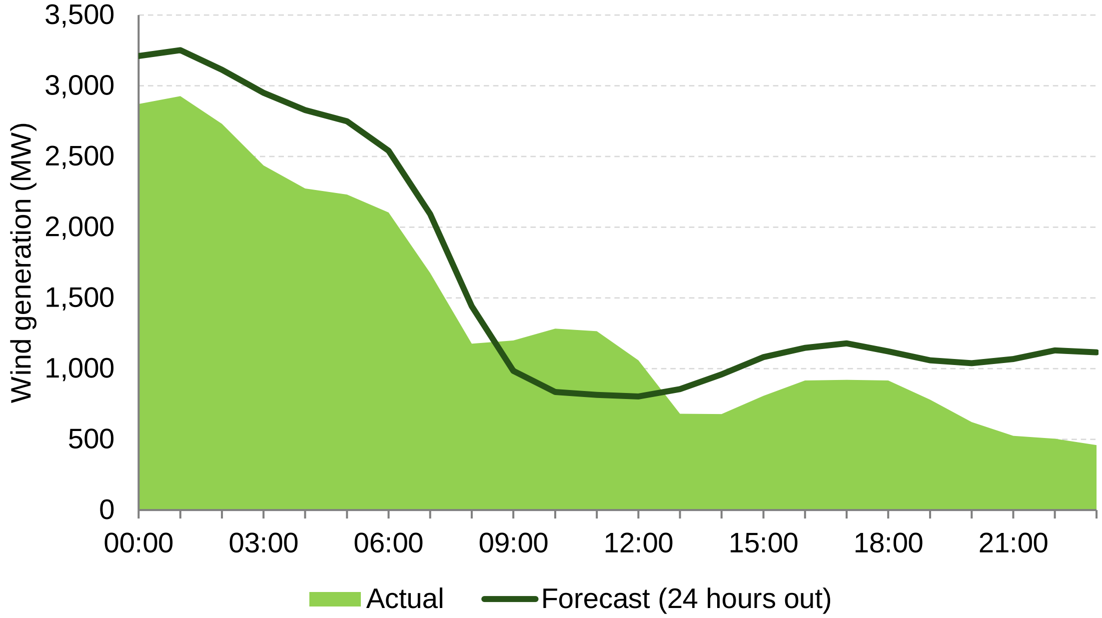
Hour ending	Anticipated supply cushion (24 hours out) (MW)	Actual supply cushion (MW)	Actual pool price ($/MWh)
20	1,570	911	$33.31
21	1,189	430	$547.19
22	1,229	391	$696.24
23	1,324	376	$999.99
24	1,514	631	$942.63

These anticipated supply cushions were higher than the actual supply cushions largely because the prevailing forecasts for wind generation were an overestimate of actual wind generation (Figure 9). For example, the wind generation forecast for HE 23 was 1,128 MW compared to actual wind generation of 458 MW, a difference of 670 MW.

However, the AESO did commit the Battle River 4 asset (155 MW) to be online for this event. Specifically, at 07:28 on July 12 Battle River 4 was committed by the AESO to run from 18:00 to 22:00. The asset came online at 18:01 and was initially dispatched for 30 MW before ramping higher when the SMP increased to $999.99/MWh at 20:31.

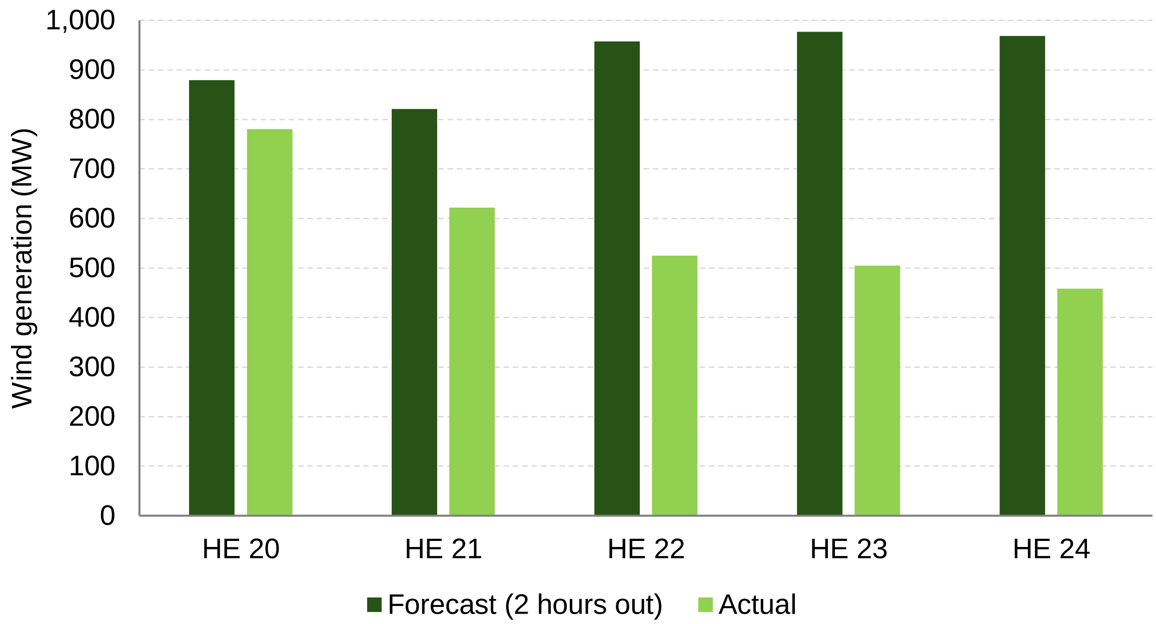
In HE 12 of July 12, the Keephills 2 asset became available again having returned from a boiler leak outage which began in HE 11 of July 8. However, the asset was commercially offline when prices hit the offer cap on July 12.

Figure 9: Wind generation and wind generation forecast 24 hours out (July 12)



The wind generation forecast continued to overestimate actual wind generation closer to real time, particularly for HE 22 to HE 24 (Figure 10). For HE 23 the wind forecast 2 hours ahead overestimated actual wind generation by 472 MW and for HE 24, the over forecast amount was 510 MW.

Figure 10: Wind generation and wind generation forecast 2 hours out (HE 20 to 24 of July 12)



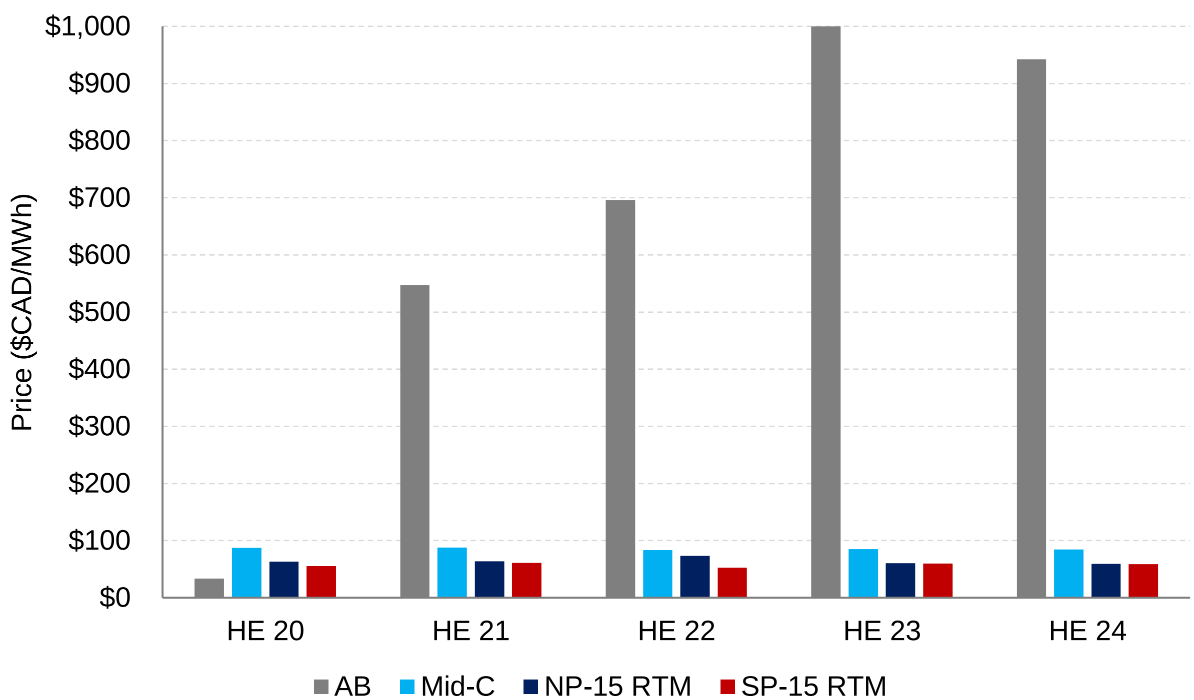
In part because of the wind forecasts, imports did not fully use the available BC/MATL capability during the July 12 event. In HE 23, when the pool price cleared at the offer cap, Alberta was a slight exporter of power (Table 9). This dynamic occurred despite pool prices in Alberta being much higher than prevailing prices in Mid-Columbia and California (Figure 11).

Table 9: Imports and exports (HE 20 to 24 of July 12)

Hour ending	BC/MATL import capability	BC/MATL net imports	BC		MATL	
			Imports	Exports	Imports	Exports
20	476	-2	175	100	0	77
21	438	98	275	100	0	77
22	367	123	300	100	0	77
23	367	-27	150	100	0	77
24	357	-109	100	100	0	109

As noted above, the Battle River 4 asset was committed by the AESO to run from HE 19 to HE 22. Beginning in HE 23 Battle River 4 was priced to come offline with the asset's entire capacity priced at $999.99/MWh. However, because of the high prices, the asset remained dispatched until the SMP fell to $999.98/MWh at 22:40. At this point the asset was dispatched to 0 MW and ramped offline. Therefore, it was subsequently unavailable for dispatch later as prices cleared at the offer cap again between 23:00 and 23:12.

Figure 11: Alberta pool prices compared to prices in other markets (HE 20 to 24 of July 12)



1.2.3 September 16 prices at the offer cap

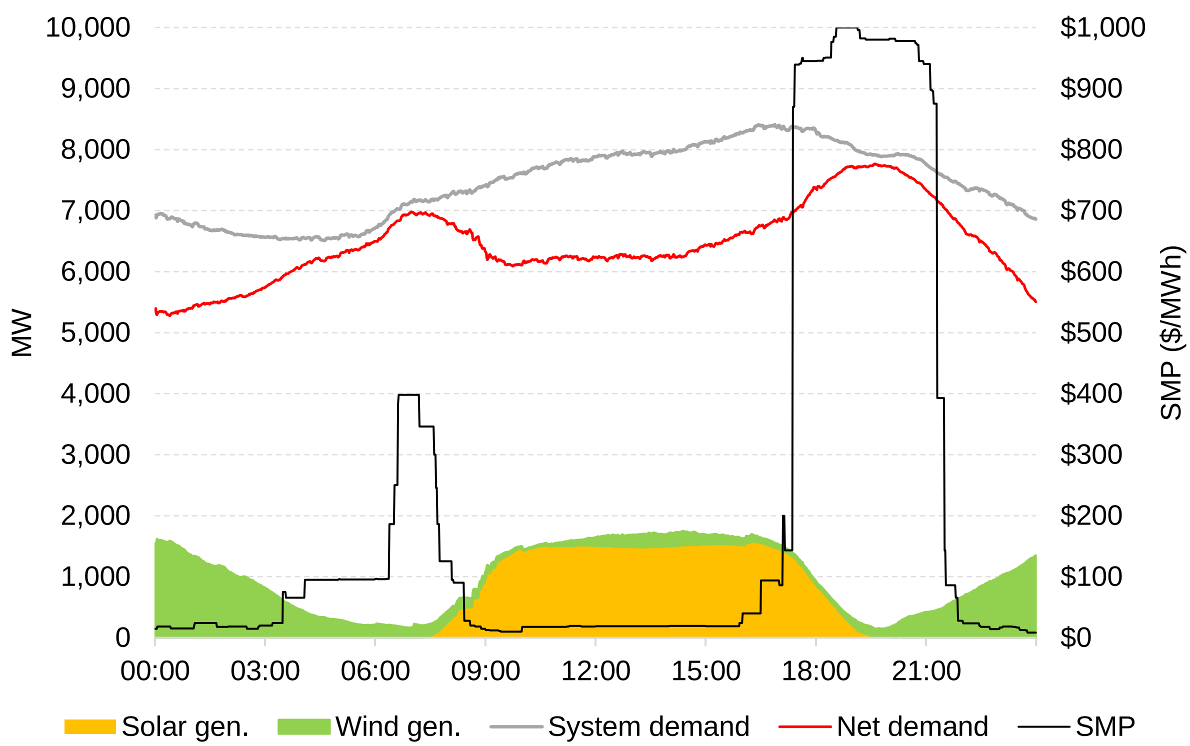
Between 18:33 and 19:08 on Tuesday, September 16, the SMP cleared at the offer cap of $999.99/MWh. The high prices in this event were driven by low intermittent supply, gas generator outages, and reduced import capability. Figure 12 illustrates the evolution of the SMP and net demand over the course of September 16. As shown, prices were elevated around the net demand peak in the evening when solar generation was declining but demand was still relatively high.

Although prices increased to the offer cap in this event, the supply cushion did not fall to 0 MW as there was still capacity available for dispatch at the top of the energy market merit order. The AESO did not declare an EEA for this event and contingency reserves were not directed to provide energy.

Wind generation during this event was low, averaging only 108 MW when the SMP was at the offer cap (Figure 12). Solar generation was declining when the SMP peaked, falling from 480 MW at 18:33 to 120 MW at 19:08. As with the EEA3 event on September 8, generation from gas-fired assets dominated supply during the SMP peak on September 16, with the generation from gas assets accounting for 90% of supply.

The import restrictions stemming from the transmission outage on line 5L92 continued on September 16. During the high prices in the evening hours, imports on BC/MATL were restricted to around 85 MW which represents a supply reduction of around 315 MW.

Figure 12: SMP and net demand (September 16)



Temperatures on September 16 were moderate with highs of 24°C in Calgary, 25°C in Edmonton, and 19°C in Fort McMurray. As a result, demand was not particularly high. AIL peaked at 10,961 MW in HE 17 which is around 1,200 MW below the record for summer demand.

Table 10 provides the major generation outages for the high price event on September 16. As shown, there were planned outages at MacKay River and Northern Prairie Power Project in addition to derates at Genesee Repower 2 and Battle River 5.

In terms of unit commitments, Sheerness 1 had been committed by the AESO earlier in the day for the morning ramp period (Table 11). This asset stayed online for the duration of the day and was fully available for the net demand peak in the evening.

The AESO also committed the Sheerness 2 and Battle River 4 assets to come online and provide power during the net demand peak on September 16 (Table 11). The Sheerness 2 asset was committed from 16:00 to 21:00 and the Battle River 4 asset was initially committed from 16:00 to 20:00, although this was later extended to 21:00. These commitments meant that there were no remaining assets commercially offline on long lead time for this event.

Table 10: Generator outages greater than 100 MW (HE 20 of September 16)

Asset name	Asset ID	Fuel type	MW on outage
Base Plant	SCR1	Cogeneration	686
Syncrude	SCL1	Cogeneration	240
MacKay River	MKRC	Cogeneration	207
Bow River	BOW1	Hydro	194
Nexen inc #2	NX02	Cogeneration	175
Dow Hydrocarbon	DOWG	Cogeneration	142
Nabiye	IOR2	Cogeneration	124
Genesee Repower 2	GNR2	Combined cycle	121
Battle River 5	BR5	Gas-fired steam	105
Northern Prairie Power Project	NPP1	Simple cycle	105
MEG1 Christina Lake	MEG1	Cogeneration	105
Cloverbar 2	ENC2	Simple cycle	101

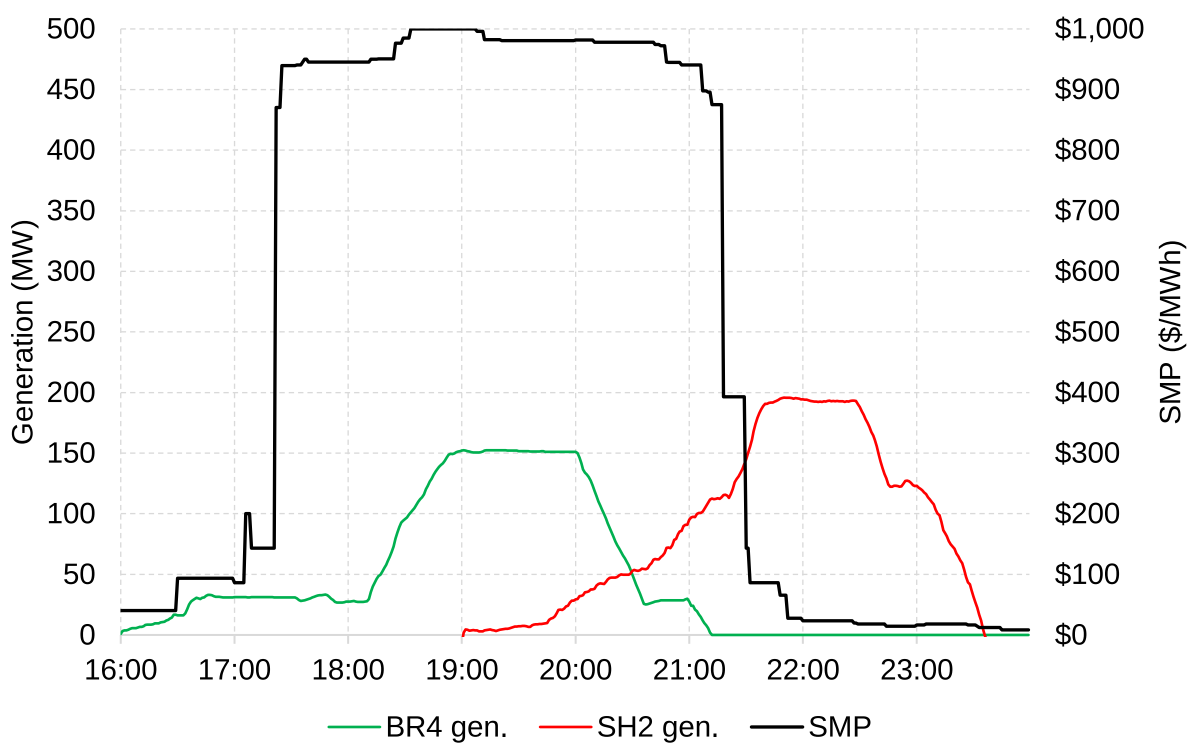
Table 11: Unit commitment directives (September 16)

Asset ID	Capacity (MW)	Issued time	Begin time	Operation start time	Operation end time
SH1	400	09/15/2025 18:26:45	09/15/2025 19:00:00	09/16/2025 06:00:00	09/16/2025 10:00:00
SH2	400	09/15/2025 15:29:38	09/15/2025 16:00:00	09/16/2025 16:00:00	09/16/2025 21:00:00
BR4	155	09/16/2025 05:28:46	09/16/2025 06:00:00	09/16/2025 16:00:00	09/16/2025 20:00:00
BR4	155	09/16/2025 19:52:12	09/16/2025 20:00:00	09/16/2025 20:00:00	09/16/2025 21:00:00

While the Battle River 4 asset started on time at 16:00, the Sheerness 2 asset was delayed and did not come online until 19:00 (Figure 13). The reason provided for the delay was that an extended tube leak outage pushed the cold start requirements. Sheerness 2 had been offline since September 12 HE 22, around four days prior to the event. Because of this delay, the Sheerness 2 asset was generating minimal amounts when the SMP peaked at the offer cap (Figure 13).

Generation from Sheerness 2 did increase to around 200 MW by 21:40 and this additional supply combined with increasing wind generation and declining demand to put downward pressure on prices; by 22:00 the SMP had fallen to $23.44/MWh.

Figure 13: SMP and the generation of BR4 and SH2 (September 16)



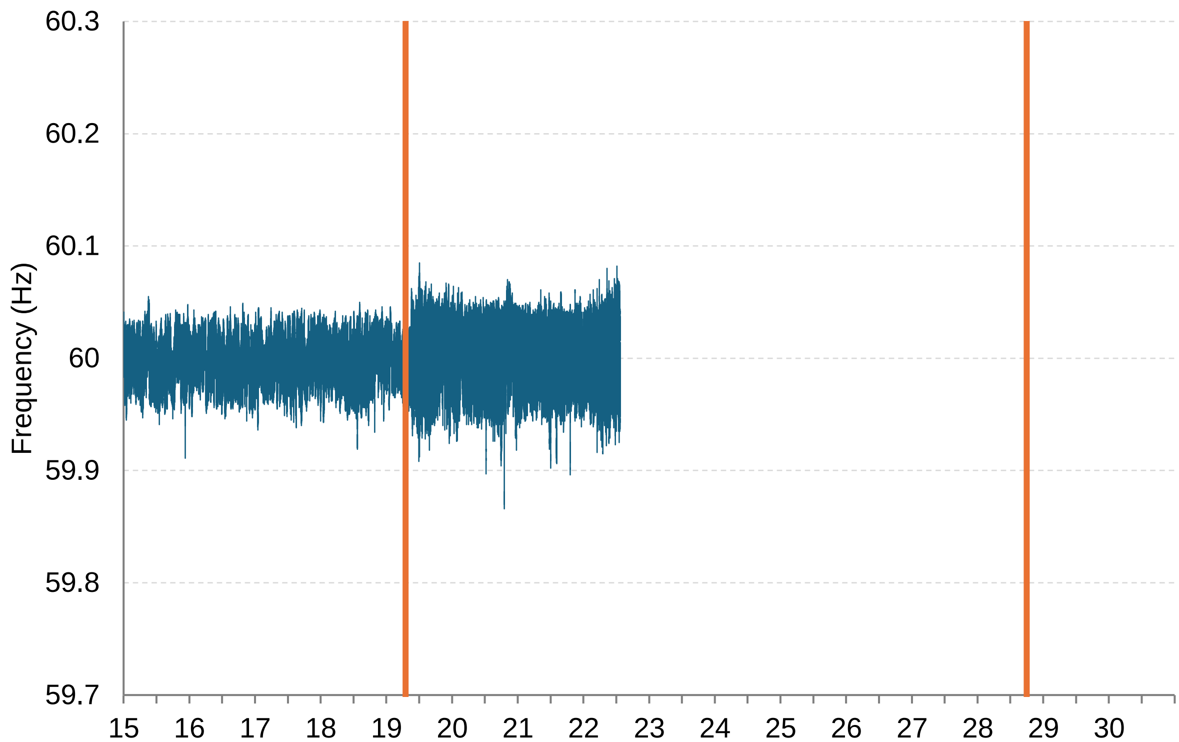
1.2.4 *September 19 to 28 BC/MATL intertie outage*

In late September the BC and MATL interties were taken offline due to planned maintenance on the BC intertie. The BC/MATL outage lasted around 10 days, running from September 19 HE 08 to September 28 HE 18. The outage was scheduled well in advance on March 31. The planned BC/MATL outage typically occurs on an annual basis in the fall as electricity demand is relatively low during this period, and it avoids the BC hydro run-off in the spring. Last year the outage ran from September 23 to October 3.

In addition to providing market access for imports and exports, the BC/MATL intertie plays an important role in stabilizing system frequency in Alberta. When the BC/MATL intertie is out of service, Alberta is islanded from the Western Interconnection and consequently has a higher routine variation in system frequency and is more susceptible to large frequency deviations when contingency events, such as generator trips, occur.

Figure 14 illustrates the higher routine variation in system frequency during the BC/MATL outage, with the orange lines depicting the start and end of the outage. In response to the higher routine variation in system frequency the AESO procured more regulating reserves during the BC/MATL outage.

Figure 14: System frequency during and around the BC/MATL outage (September 15 to 30; data increment is 2 seconds)



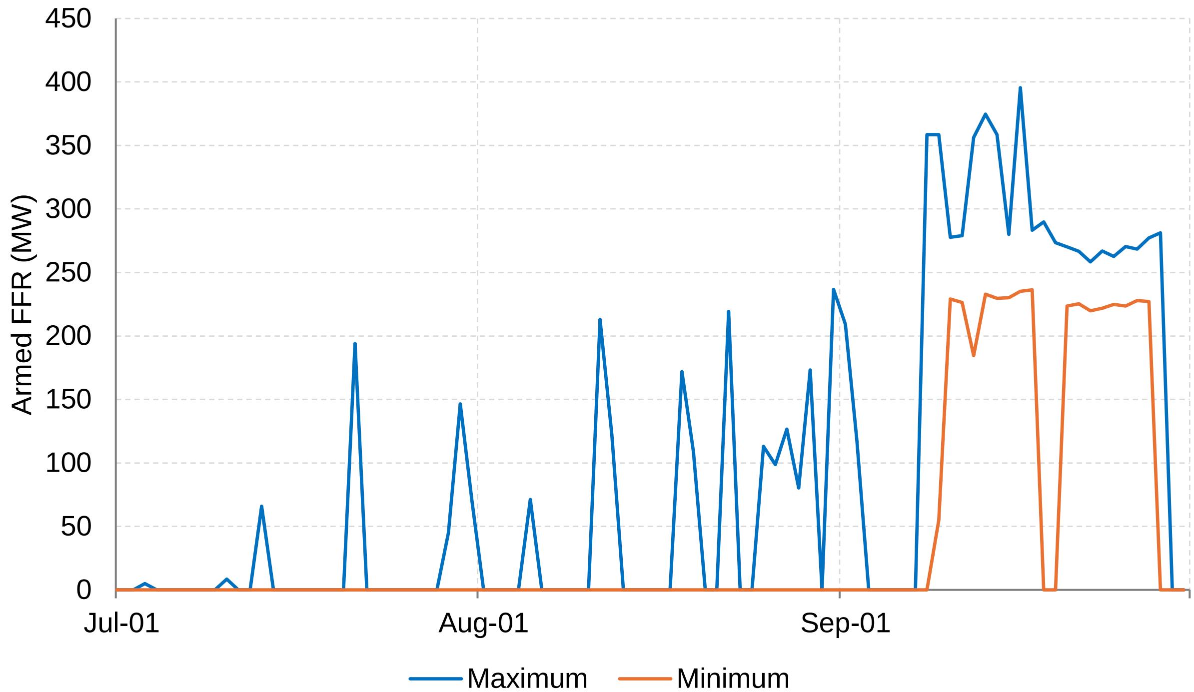
Normally the AESO procures 135 MW of regulating reserves for the off-peak hours and 210 MW for the on-peak hours. However, during the BC/MATL outage the AESO increased these volumes by 50 MW to 185 MW for the off-peak and 260 MW for the on-peak. This increased volume of regulating reserves provided the AESO with a higher response for small changes in system frequency.

When BC/MATL is offline Alberta is more susceptible to frequency declining meaningfully following large generator trips. If the BC/MATL intertie is in service Alberta receives an immediate in-rush of power from BC and Montana in response to declining system frequency. Consequently, large generator trips in Alberta often result in relatively small changes to system frequency. However, when BC/MATL is out of service Alberta no longer receives this increase in supply in response to declining frequency.

To deal with this issue, the AESO procured more FFR volumes than normal during the BC/MATL outage in late September (Figure 15). Indeed, the AESO procured more FFR volumes for much of September because earlier in the month a transmission outage on line 5L92 restricted import volumes.

The FFR product is supplied by load and battery assets which are contracted to provide a response (i.e. reduce load or increase supply) within 12 or 24 cycles (0.2 or 0.4 seconds) when system frequency falls to 59.7 or 59.5 Hz. The additional volume of FFR provided the AESO with a higher frequency response following large contingency events.

Figure 15: Minimum and maximum of armed FFR (July 1 to September 30)



It is also worth noting that the planned BC/MATL outage occurred concurrently with a major planned outage on the Alberta natural gas network. Specifically, between September 22 and 29, pipeline maintenance in the Northeast Delivery Area (NEDA) reduced firm gas capacity down to

67%, meaning that natural gas generators in the area had less available capacity because of insufficient natural gas supply.

Natural gas generators in the NEDA area include Sheerness 1 (400 MW), Sheerness 2 (400 MW), Battle River 4 (155 MW), and Battle River 5 (395 MW). Given that Alberta can rely heavily on natural gas generation to meet demand when the supply of imports is reduced (as was the case during the EEA3 event on September 8), the MSA believes it is worth coordinating outages on the power system with those on the natural gas network, so that major outages like these do not overlap in the future.

During the BC/MATL outage this year there were only three AIES event logs recording frequency deviations, a notable reduction from the 28 event logs during the outage last year. During the 2024 outage, system frequency fell below 59.7 Hz on three occasions, whereas the lowest frequency recorded during this year's outage was 59.82 Hz.

The relatively stable frequency this year was due to the fact that there were no major asset trips and no significant drops in wind generation. Table 12 summarizes the frequency deviation events which occurred during the BC/MATL outage in Q3.

Table 12: Frequency deviations during the BC/MATL outage

Date and time	Frequency (Hz)
September 20, 19:08:18	59.866
September 24, 17:30:54	59.824
September 24, 18:52:44	59.857
September 26, 18:52:28	59.866
September 27, 03:15:02	59.866
September 27, 18:52:52	59.864

Most of the frequency deviations during the outage period were driven by drops in wind generation at the Windrise asset. On September 20, output at Windrise fell from 170 MW at 19:07:52 to 9 MW by 19:09:00, a decline of approximately 160 MW within one minute (Figure 16). This resulted in system frequency falling to 59.87 Hz at 19:08:18.

Similar events were observed around 18:52 on September 24, 26, and 27 (Table 12), where frequency deviations corresponded with declines in generation at Windrise. The decline in generation at Windrise around 18:52 was observed relatively consistently during the BC/MATL outage (Figure 17) due to an automated bat curtailment plan.

On September 24, between 17:00 and 19:30, solar generation decreased from 1,425 MW to 48 MW, and between 17:00 and 17:30, generation at Cascade 1 and 2 declined due to dispatch changes. As the ramp-down of solar generation and Cascade 1 and 2 occurred faster than the increase in replacement supply, frequency declined (Figure 18). At 17:30:54 frequency fell to 59.82 Hz, the lowest observed during the BC/MATL outage.

Figure 16: Frequency and Windrise generation (September 20)

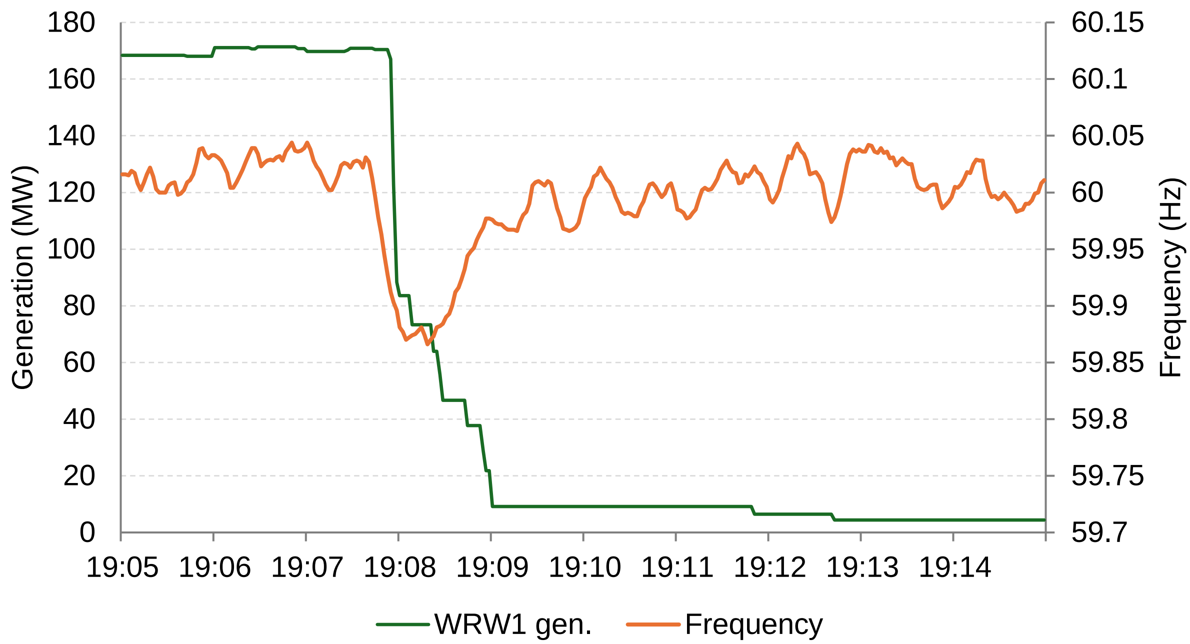


Figure 17: Windrise generation (September 19 to 28)

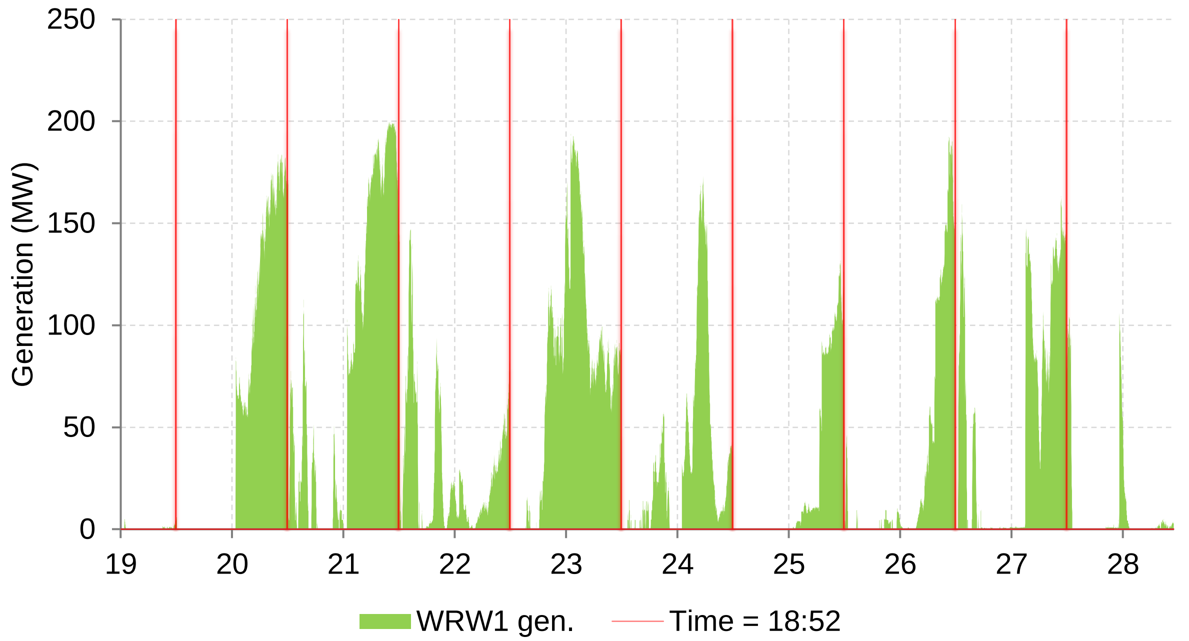
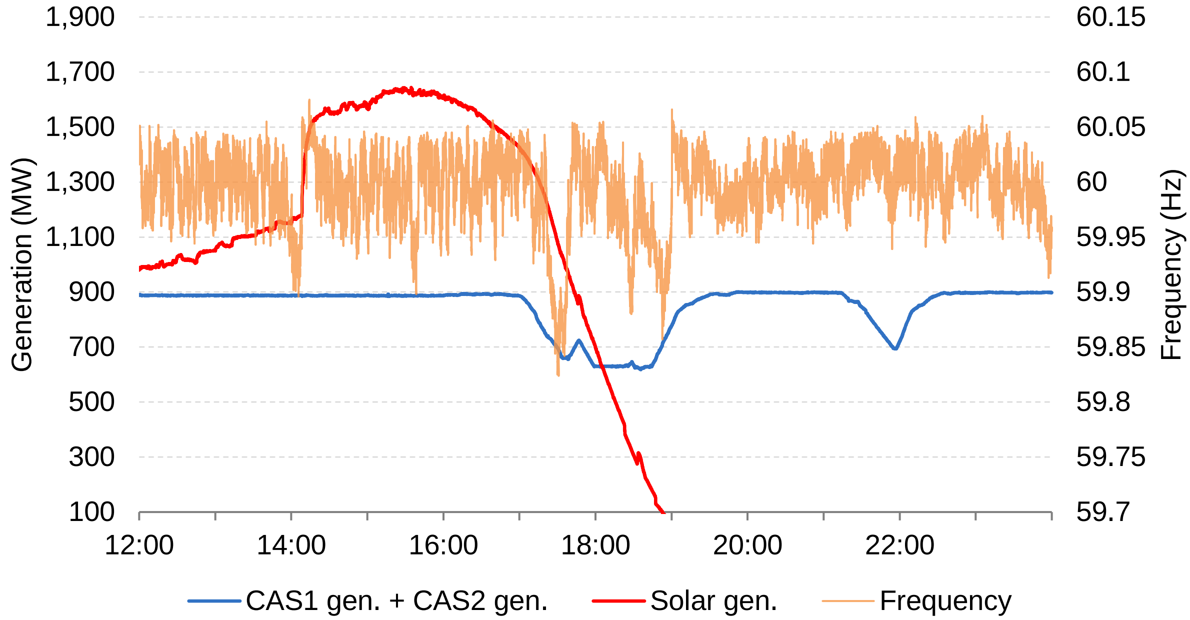


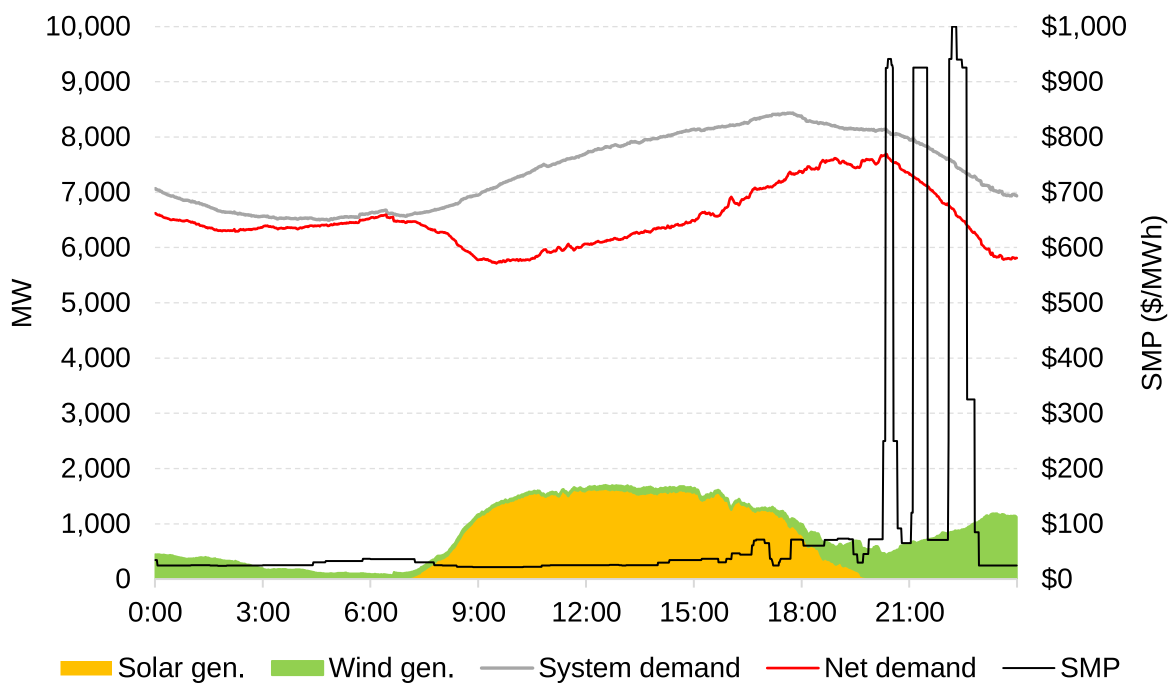
Figure 18: Frequency, solar generation, CAS1 and CAS2 generation (September 24)



1.2.5 September 1 prices at $999.93/MWh

On September 1, higher prices were observed from HE 21 through HE 23, with the SMP reaching $999.93/MWh between 22:11 and 22:19 (Figure 19). The higher prices were driven by a combination of high net demand, reduced imports, and supplier offer behaviour.

Figure 19: SMP and net demand (September 1)



Temperatures were warm in Calgary, reaching a high of 28°C, but milder in Edmonton and Fort McMurray with highs of 23°C and 18°C, respectively. The warm weather contributed to AIL peaking at 11,181 MW in HE 18, which is around 1,000 MW less than record summer demand.

Table 13 summarizes the major generation outages in HE 23 of September 1. A forced outage at Cascade 2 due to a transformer oil leak began in HE 12 of August 31 and lasted until HE 18 of September 4. Battle River 5 and Genesee Repower 2 were also derated. Most gas-fired steam capacity was online and generating; only Battle River 4 (155 MW) remained commercially offline on long lead time.

Wind generation was low for most of the day, averaging 269 MW (Figure 19). Wind generation reached its minimum of 30 MW at 16:44 before gradually increasing to 1,190 MW at 23:20. Solar output was high during peak hours with a maximum of 1,634 MW at 12:33. However, as solar output declined in the evening, net demand increased above 7,500 MW.

In response to the high net demand, Alberta imported power on the BC/MATL intertie from HE 18 through HE 21 (Table 14). In HE 19 and HE 20 full import capability was used. These imports helped to moderate pool prices between HE 18 and HE 20, resulting in an average of $56.95/MWh over this period.

However, in HE 21 the import capability on BC/MATL was not fully used despite similar levels of net demand. Imports declined and the SMP rose sharply, reaching $941.32/MWh between 20:24 and 20:30 as the supply cushion fell to 651 MW.

Table 13: Generator outages greater than 100 MW (HE 23 of September 1)

Asset name	Asset ID	Fuel type	MW on outage
Base Plant	SCR1	Cogeneration	681
Genesee Repower 1	GNR1	Combined cycle	466
Cascade 2	CAS2	Combined cycle	450
Bow River	BOW1	Hydro	204
Syncrude	SCL1	Cogeneration	175
Firebag	SCR6	Cogeneration	157
Dow Hydrocarbon	DOWG	Cogeneration	138
Genesee Repower 2	GNR2	Combined cycle	119
Battle River 5	BR5	Gas-fired steam	105
MEG1 Christina Lake	MEG1	Cogeneration	102
Cloverbar 2	ENC2	Simple cycle	101

In HE 22, Alberta became a net exporter of power (Table 14). Wind generation increased slightly but remained relatively low at an average of 714 MW, maintaining high net demand conditions. Consequently, prices stayed elevated in HE 22, with the SMP reaching $925.43/MWh between 21:06 and 21:30 when the supply cushion was 850 MW.

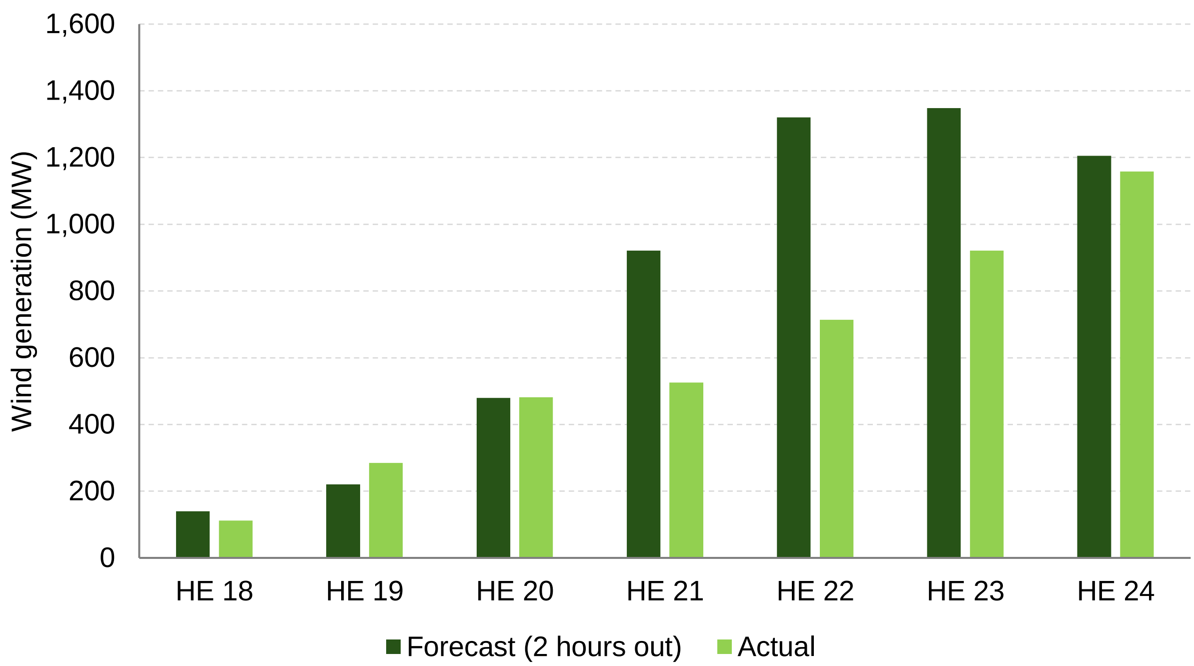
Table 14: Imports and exports (HE 18 to 24 of September 1)

Hour ending	Pool price	BC/MATL import capability	BC/MATL net imports	BC		MATL	
				Imports	Exports	Imports	Exports
18	$47.76	525	363	200	0	213	50
19	$64.83	525	522	409	0	121	8
20	$58.29	521	521	395	0	126	0
21	$292.08	521	313	400	112	25	0
22	$414.95	438	-295	50	295	0	50
23	$568.23	434	-490	25	465	0	50
24	$24.66	430	-212	0	162	0	50

In HE 23, wind generation continued to rise, averaging 921 MW, while demand declined. However, these fundamentals were partly offset by the start of a scheduled outage at Genesee Repower 1 (466 MW). Net exports also increased to 490 MW further tightening market conditions. These factors contributed to higher prices, with the SMP reaching $999.93/MWh between 22:11 and 22:19. The supply cushion during this period was 590 MW.

Wind forecasts overestimated wind generation for HE 21 through HE 23 (Figure 20). The forecasts two hours ahead exceeded actual output by 395 MW in HE 21, 607 MW in HE 22, and 427 MW in HE 23. These overestimates contributed to the underutilization of import capacity in HE 21 and to the net exports in HE 22 and HE 23.

Figure 20: Wind generation and wind generation forecast 2 hours out (HE 18 to 24 of September 1)



In addition, the high prices in HE 23 were partly the result of supplier offer behaviour. The amount of non-hydro capacity offered above $250/MWh increased by 225 MW compared to HE 22, primarily due to the capacity of Sheerness 1 being offered above $999.93/MWh in $0.01/MWh increments up to $999.99/MWh (Table 15).

In this hour, Sheerness 1 was operating under a unit commitment directive issued by the AESO (Table 16). The directive, issued at 21:54, instructed the asset to remain online and generating at least its minimum stable generation throughout HE 23. Between 22:11 and 22:19, while subject to the directive, the asset's 120 MW block came into merit at $999.93/MWh and they received an energy market dispatch that was equivalent to the MW required by the directive. Had the asset not been committed by the AESO, the supply cushion in HE 23 would have fallen to around 180 MW.

Table 15: Sheerness 1 offer blocks (HE 23 of September 1)

Block number	Block size (MW)	Block price ($/MWh)
0	120	$999.93
1	70	$999.94
2	50	$999.95
3	50	$999.96
4	20	$999.97
5	50	$999.98
6	40	$999.99

Table 16: Unit commitment directives (September 1)

Asset ID	Capacity	Issued Time	Begin Time	Operation Start Time	Operation End Time
SH1	400	09/01/2025 21:54:13	09/01/2025 22:00:00	09/01/2025 22:00:00	09/01/2025 23:00:00

1.2.6 September 3 - large difference between the constrained and unconstrained SMP

The unconstrained SMP represents the intersection of demand and the unconstrained supply curve. This unconstrained supply curve includes generation that is constrained by transmission congestion. In contrast, the constrained SMP reflects the intersection of demand and constrained supply which excludes generation that could not be delivered due to transmission congestion.

Therefore, when transmission constraints occur, constrained supply decreases below unconstrained supply and typically results in a higher constrained SMP relative to the unconstrained SMP. It is the unconstrained SMP that sets price in Alberta. However, generators that are dispatched above the unconstrained SMP receive their offer price.

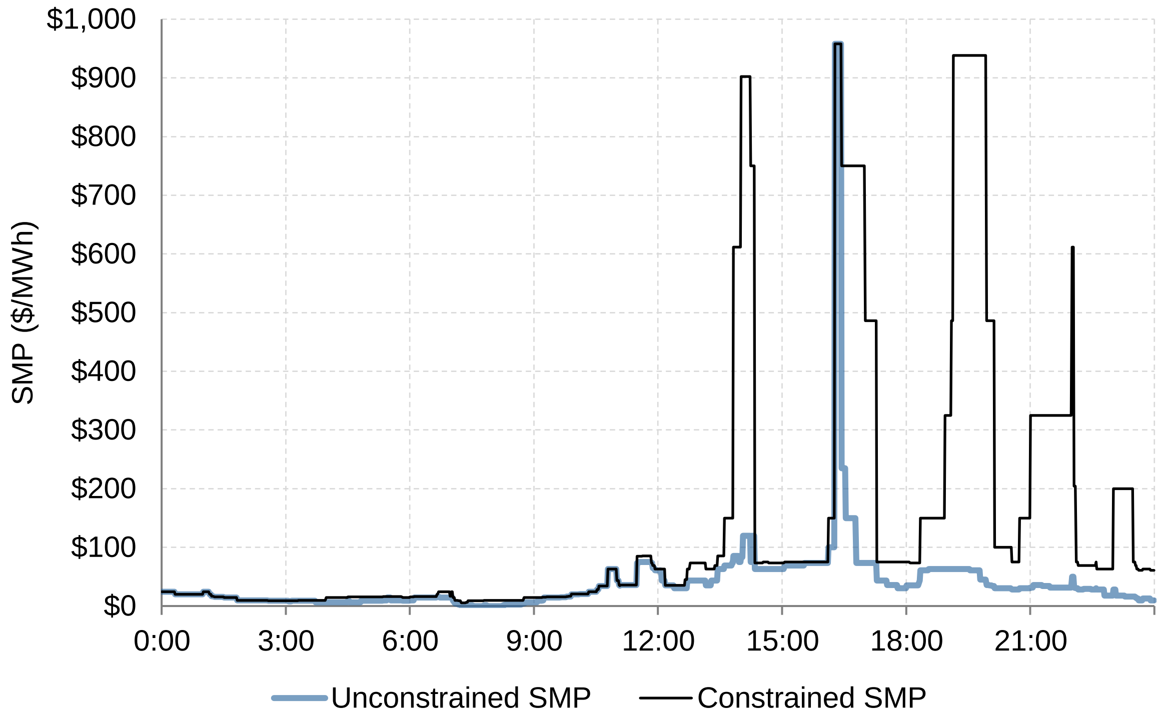
September recorded the second-largest difference between the average constrained SMP and the average unconstrained SMP so far this year, and the largest in the quarter (Table 17). This was primarily driven by the difference between the constrained and unconstrained SMP on Wednesday, September 3.

On September 3, the daily average difference between the constrained and unconstrained SMP reached $100.53/MWh, the highest recorded in the quarter. The constrained SMP averaged $140.68/MWh while the unconstrained SMP averaged $40.15/MWh. The largest difference occurred between 19:47 and 19:56 when the constrained SMP peaked at $938.25/MWh and the unconstrained SMP was $45.00/MWh (Figure 21).

Table 17: Monthly average constrained and unconstrained SMP (January to September)

Month	Average constrained SMP ($/MWh)	Average unconstrained SMP ($/MWh)	Difference ($/MWh)
January	$31.17	$30.36	$0.81
February	$56.74	$55.77	$0.97
March	$35.67	$34.76	$0.92
April	$35.56	$33.69	$1.87
May	$51.28	$40.99	$10.29
June	$50.20	$46.75	$3.45
July	$33.18	$31.18	$1.99
August	$52.48	$50.35	$2.14
September	$78.21	$73.05	$5.16

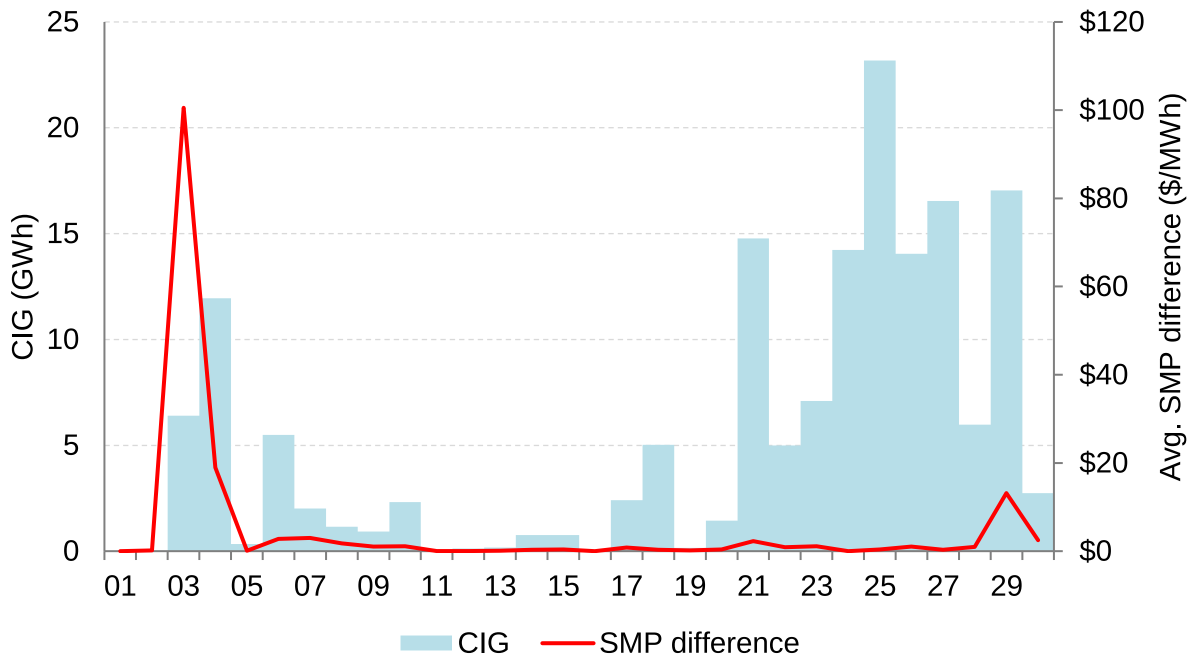
Figure 21: Unconstrained SMP and constrained SMP (September 3)



Large differences between the constrained and unconstrained SMP are often associated with periods of high constrained intermittent generation (CIG), which typically coincide with high output from intermittent resources. However, on September 3, intermittent generation was moderate. Average wind generation was 1,430 MW (close to the monthly average of 1,346 MW) while solar generation during peak hours averaged 457 MW (below the monthly average of 717 MW).

As a result, CIG volumes on September 3 were relatively low (Figure 22). The MSA estimates that total CIG reached 6.40 GWh on this day, well below the 23.18 GWh recorded on September 25. Despite this, the difference between the constrained and unconstrained SMP was elevated on September 3 due to the loss of transmission lines 1053L, 9L20, and 610L. These outages resulted in transmission constraints on wind generation (373 MW at 19:47) and gas generation (95 MW at 19:47).

Figure 22: CIG and average difference between the constrained and unconstrained SMP (September 1 to 30)

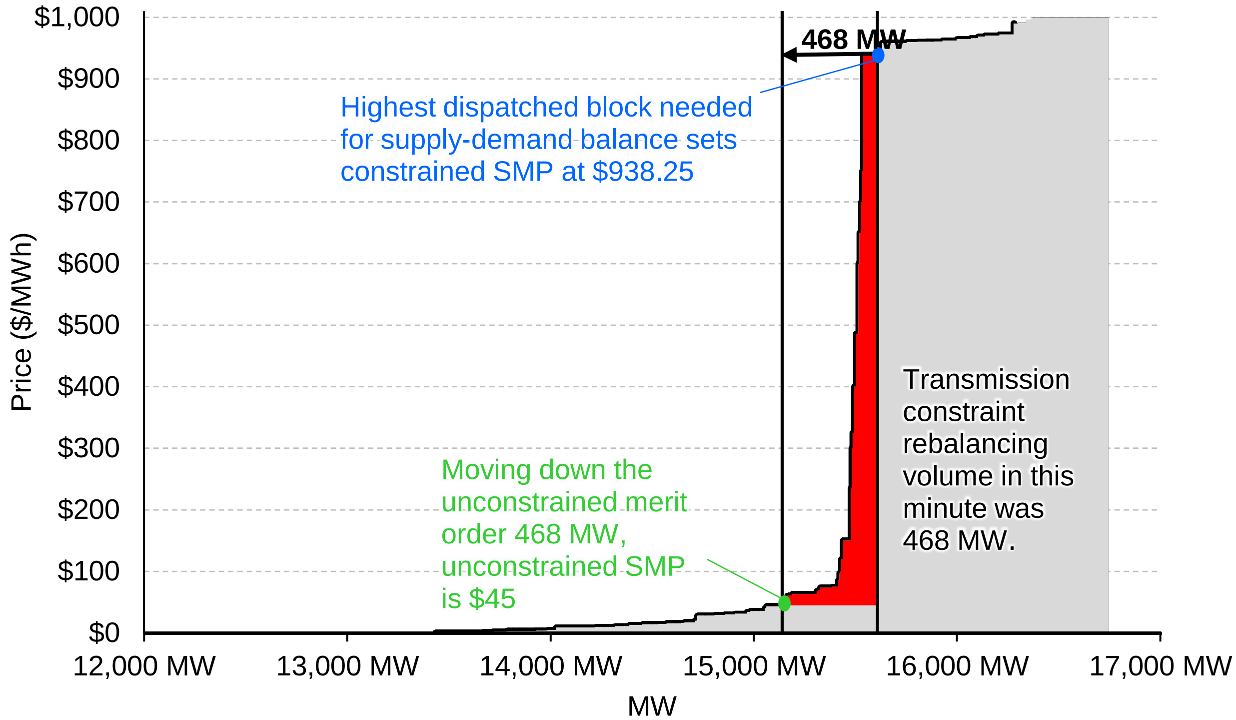


Market fundamentals on September 3 contributed to prices clearing higher up the supply curve where it is steeper (Figure 23). High demand and the exercise of market power by suppliers pushed the constrained SMP upward. Average demand on September 3 was 10,244 MW, reaching a maximum of 10,908 MW in HE 18. In contrast, demand was lower later in the month when CIG volumes were higher.

In addition to elevated demand, large volumes of gas capacity were offered at high prices. On September 3, an average of 1,157 MW of non-hydro capacity was offered above $250/MWh, 305 MW higher than the monthly average. No capacity was offered between $750/MWh and $900/MWh on September 3, and during HE 21 to HE 23 no capacity was offered between

$500/MWh and $900/MWh. This offer behaviour resulted in a steep supply curve which contributed to a large difference between the constrained and unconstrained SMP (Figure 23).

Figure 23: The unconstrained energy market supply curve (September 3 19:47)



1.2.7 September 21 lowest daily average pool price

The daily average pool price on Sunday, September 21 was $0.75/MWh, the lowest on record. As shown in Table 18, four of the five lowest daily average pool price days occurred in Q3 and Q3 2024. These lower prices were primarily driven by elevated wind generation combined with low weekend demand.

Table 18: The lowest daily average pool prices

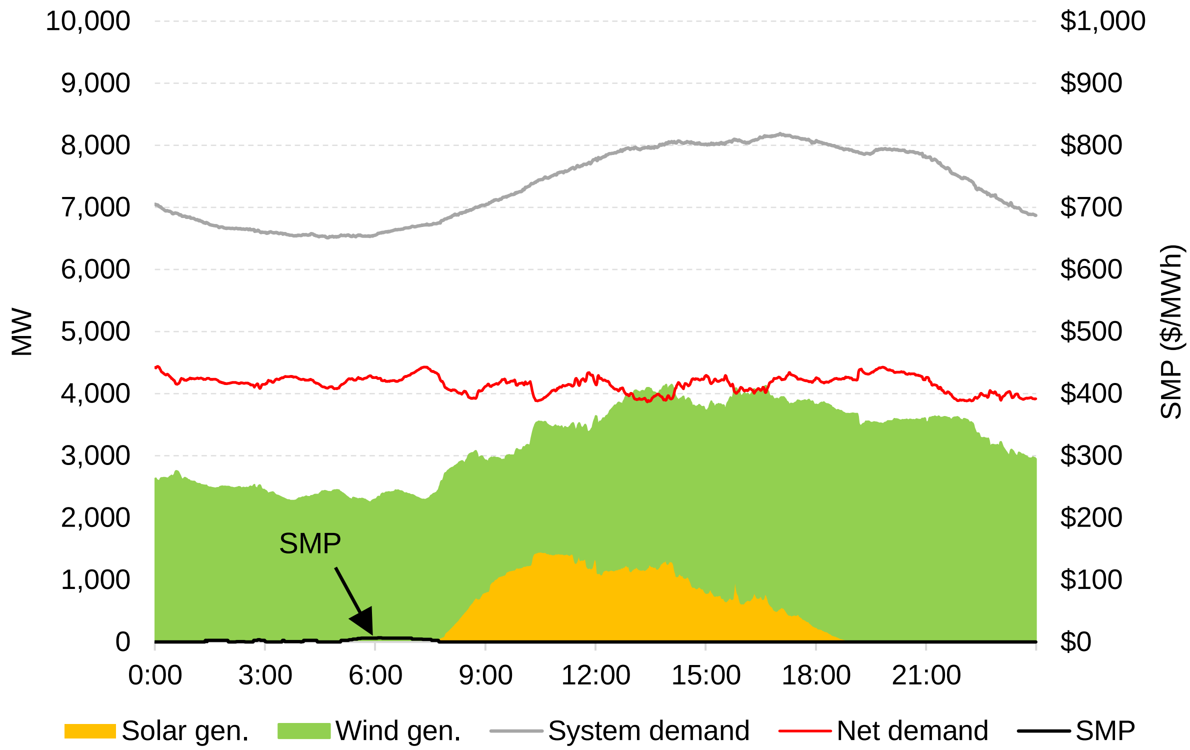
Rank	Date	Weekday	Avg. pool price ($/MWh)	Avg. wind generation (MW)
1	September 21, 2025	Sunday	$0.75	2,787
2	August 24, 2024	Saturday	$0.79	2,501
3	September 27, 2025	Saturday	$0.83	2,289
4	September 29, 2024	Sunday	$1.33	2,314
5	February 23, 2025	Sunday	$1.45	3,437

The pool price on September 21 remained at the price floor of $0/MWh for a total of 17 hours, including HE 01 and from HE 09 through HE 24. In total, the SMP was at the floor for 73% of the day. Even at its highest, the pool price reached only $6.27/MWh in HE 07.

The AESO declared a supply surplus during two periods on this day, from 08:44 to 10:12 and from 22:14 to 00:08 the following day, reflecting excess supply relative to prevailing demand.

The low prices on September 21 were driven by high wind generation, low demand, low natural gas prices, and the planned outage on the BC/MATL intertie which meant that exports were unavailable. Wind generation was exceptionally strong and consistent throughout the day, averaging 2,787 MW (Figure 24), the highest daily average in September.

Figure 24: SMP and net demand (September 21)

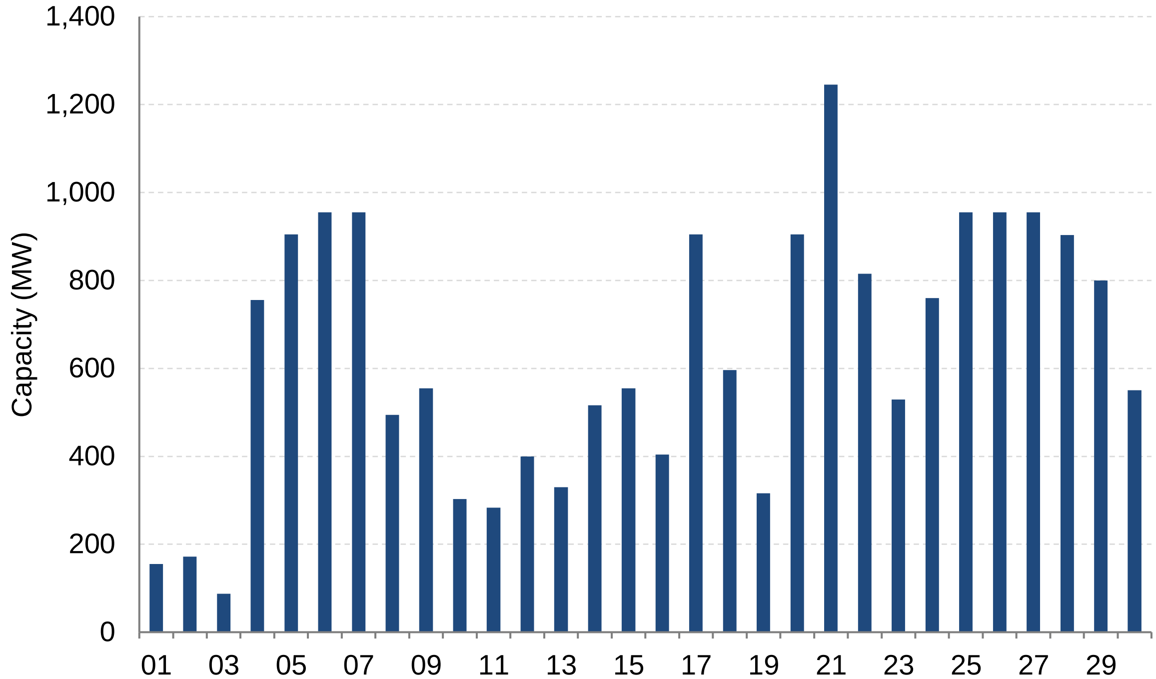


Solar generation was moderate, averaging 598 MW during peak hours, as it peaked at 1,460 MW at 10:30 and gradually decreased over the remainder of the day.

Weekend demand levels and mild temperatures (a high of 19°C in Calgary, 17°C in Edmonton, and 19°C in Fort McMurray) contributed to lower demand with AIL peaking at 10,586 MW in HE 18.

As noted in section 1.1, natural gas prices were low in late September. On September 21, the AB-NIT sameday natural gas price fell to negative $0.04/GJ. Nevertheless, the amount of gas-fired steam capacity that was commercially offline on long lead time was the highest of the month at 1,245 MW (Figure 25). Battle River 4 (155 MW), Battle River 5 (290 MW), Sheerness 1 (400 MW), and Sheerness 2 (400 MW) were all offline on long lead time for the entire day.

Figure 25: Average amount of gas-fired steam capacity on long lead time (September 1 to 30)



1.3 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. The MPMR and SCR are implemented through ISO rules 206.1 and 206.2, respectively.

1.3.1 Market Power Mitigation Regulation and ISO rule 206.1

Under ISO rule 206.1, a secondary offer price limit equal to the greater of either $125/MWh or 25 times the day-ahead natural gas price is triggered when the Monthly Cumulative Settlement Interval Net Revenue (MCSINR) exceeds 1/6 of the annualized avoidable costs of a reference combined cycle generating unit.

The secondary offer price limit was not triggered in Q3, as the MCSINR reached only 25%, 53%, and 86% of the threshold in July, August, and September, respectively. September was the closest month to triggering the secondary offer cap since it was first triggered in July 2024.

As in previous quarters, net revenues tend to accumulate primarily from high price outlier events. For the threshold to be exceeded in a month, approximately 0.14% of the threshold must be accumulated per hour, on average. Even in September, net revenues were below this level in approximately 89% of hours and were negative in 31% of hours. Net revenues accumulated to 55% of the threshold over just the top 35 hours.

1.3.2 Supply Cushion Regulation and ISO rule 206.2

Under ISO rule 206.2, the AESO must perform a forecast of supply cushion, called anticipated supply cushion (ASC), and issue unit commitment directives (UCD) to eligible long lead time (LLT) assets when the ASC falls below 932 MW. The AESO must choose which eligible LLT assets to direct based on economic merit and physical constraints, for which it uses a tool called Power Optimisation (PowerOp).

In Q3, 41 UCDs were issued; however, as described below, one of these UCDs did not result in an asset being committed. Therefore, in effect, there were 40 UCDs in Q3. This was the highest number of UCDs in a quarter since the interim measures were introduced, topping the 30 UCDs issued in Q2.

Table 19 shows the estimated price effect of the 40 UCDs in Q3.[1] Over the quarter, the MSA estimates that the average pool price was lowered by $9.92/MWh or 19% because of the UCDs. This estimate assumes that the LLT assets under UCD would have remained commercially offline absent the UCD.

Table 19: Estimated price impact of unit commitment directives in Q3

Time period	Actual average pool price ($/MWh)	Estimated average pool price without unit commitment directives ($/MWh)	Percentage change (%)
July	$31.19	$32.75	-5%
August	$50.35	$61.88	-23%
September	$73.06	$89.96	-23%
Q3	**$51.29**	**$61.21**	**-19%**

While the estimated price without UCDs for September was $89.96/MWh, the MSA estimates that the secondary offer cap would have come into effect, putting downward pressure on resulting pool prices. Therefore, the actual effect of UCDs is likely smaller than this estimate.

Despite similar estimated price effects, UCDs had different impacts in August and September. Generally, in August, UCDs resulted in one or more LLT assets being committed online while others stayed offline, keeping the supply cushion at or near the 932 MW threshold. This tended to result in avoided high price events.

[1] The methodology for measuring the price impact of UCDs was described in section 1.3.2.2 of the MSA Quarterly Report for Q3 2024.

In contrast, in September, supply conditions were tighter and high prices occurred despite UCDs, often while all LLT assets were online. Instead, the UCDs tended to reduce the duration and severity of these events.

1.3.2.1 Unit commitment directive on September 19, 2025

As reported on the AESO website, the AESO issued a UCD to Battle River 4 (BR4) at 19:25 on September 18, which required BR4 to operate from 19:00 to 23:00 on September 19. However, the AESO later instructed the pool participant for BR4 to disregard the UCD, because BR4 was on a forced outage and was not capable of starting up in time to meet the UCD.

In Proceeding 29093, the Alberta Utilities Commission (Commission) directed the AESO to publicly report on UCD issuance in real time, stating that if the AESO fails to do so, “then a market participant who receives a UCD has more information than others who didn’t receive one” and that “this information asymmetry has the potential to affect the FEOC operation of the market.”[2]

In the MSA’s view, the UCD issued to BR4 for September 19, and similar UCDs in April, described more in the MSA’s Q2 2025 report, resulted in persisting asymmetry between the UCDs reported on the AESO website and the information available to market participants who received UCDs. While publishing these UCDs is consistent with the Commissions’ direction, the MSA recommends that the AESO consider adding additional information to its public report to indicate when it has instructed a pool participant to disregard a UCD.

1.4 Market power and offer behaviour

1.4.1 Market power

As part of our market monitoring, the MSA calculates counterfactual prices based on short-run marginal costs (SRMC). These counterfactual prices can then be compared against actual prices to calculate mark-ups. The mark-up between actual and counterfactual prices is indicative of market power, with a higher mark-up indicating more market power.

Table 20 provides monthly average actual and counterfactual prices year-over-year. In Q3 counterfactual prices were low across the quarter reflecting low natural gas prices in Alberta.

Mark-ups in Q3 were lowest in July with an average of $4.20/MWh, the lowest since December 2024. The lower markups in July were caused by mild weather conditions and high thermal availability which combined to increase competition in the energy market.

[2] Decision 29093-D02-2025, paras. 78 and 79.

Table 20: Actual and counterfactual average prices by month (Q3 and Q3 2024)

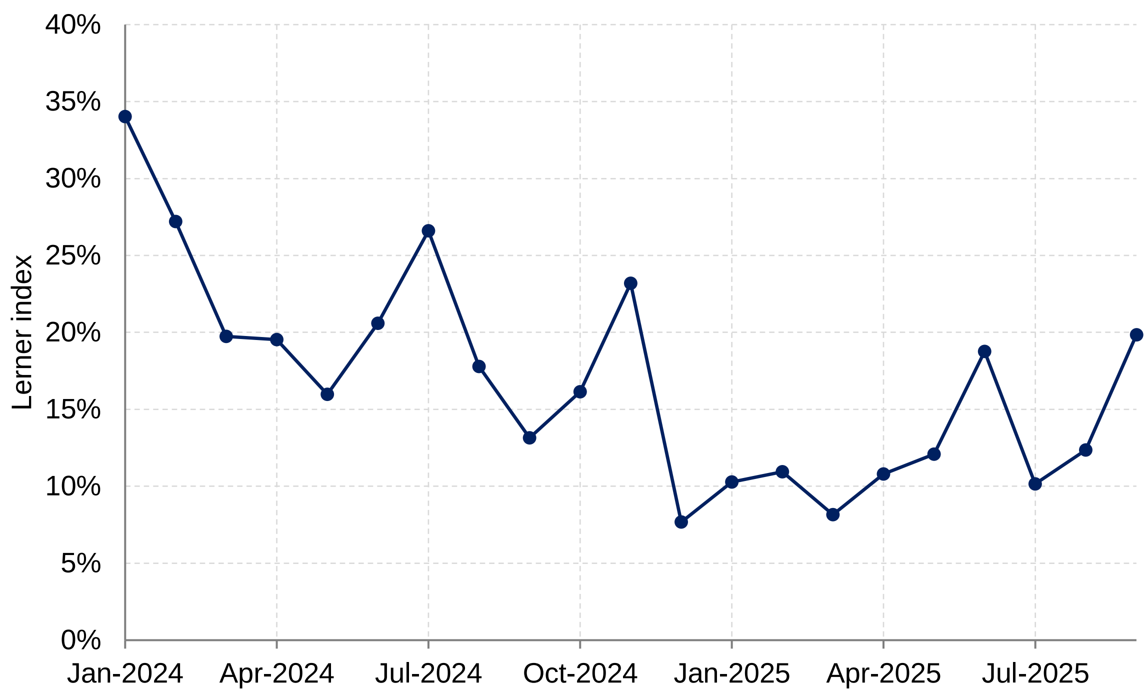
	2024			2025		
	Actual	**Counterfactual**	**Difference**	**Actual**	**Counterfactual**	**Difference**
Jul	$88.62	$50.32	$38.30	$31.19	$26.99	$4.20
Aug	$34.26	$24.34	$9.92	$50.35	$23.25	$27.10
Sep	$42.80	$21.73	$21.07	$73.05	$27.62	$45.42
Q3	**$55.36**	**$32.24**	**$23.12**	**$51.29**	**$25.94**	**$25.36**

In September, mark-ups were higher averaging $45.42/MWh, the highest since January 2024. The higher mark-ups in September were largely driven by reduced import capability, generator outages, and higher demand year-over-year. In a relatively small number of hours, these factors combined with low intermittent supply to reduce competition in the energy market and increase prices. The higher prices in these hours increased the monthly average mark-up meaningfully.

Overall, the average mark-up in Q3 was $25.36/MWh which is a 10% increase compared to Q3 last year, and represents an 81% increase compared to Q2.

The Lerner index is a measure of market power which calculates what percentage of the observed price is attributable to mark-up. A higher Lerner index indicates more market power. Figure 26 illustrates the monthly average Lerner index going back to January 2024. In this analysis, the Lerner index is set to zero in hours where the actual price is less than the market's SRMC, meaning there is no market power assumed in these hours. In Q3 the average Lerner index was 14% which is slightly lower than the 19% observed in Q3 last year.

Figure 26: Average Lerner index (January 2024 to September 2025)



The Lerner index declined over the course of 2024, which partly reflects increased competition from the supply of Cascade 1 and 2. In 2025 the average Lerner index has been relatively low at around 10% for most months, with June and September being the exceptions. The Lerner index was 19% in June and 20% in September. The higher Lerner index in June was driven by gas generator outages and low wind supply. In September the higher Lerner index was driven by constraints on import supply, gas generator outages, and higher demand year-over-year.

The exercise of market power can lead to static inefficiencies in the short-run, specifically productive and allocative inefficiencies. Productive inefficiencies occur when lower cost generating assets are priced out of the market and higher cost assets supply power instead. Allocative inefficiencies occur when the exercise of market power leads to prices above SRMC and demand is lowered as a result.

In the context of Alberta's energy only market, these short-run inefficiencies should be weighed against long-run efficiencies, including the supply of new capacity. Short-run inefficiencies are tolerable to the extent that long-run efficiencies are contingent on them.

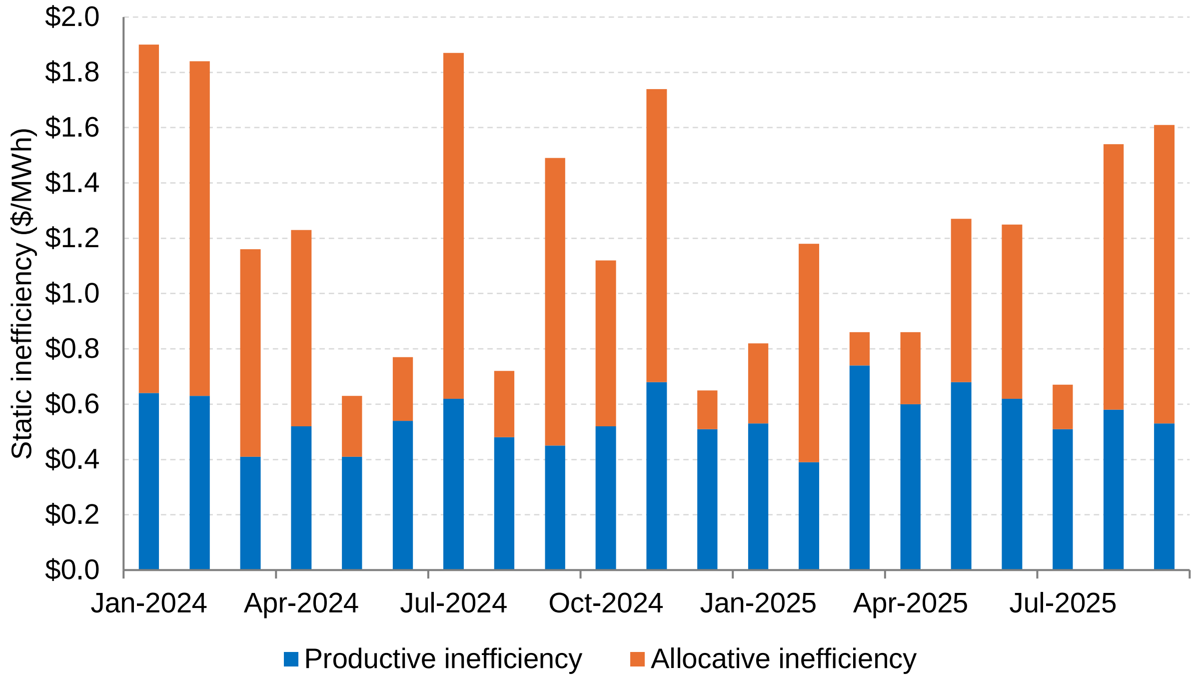
The average value for static inefficiency in Q3 was $1.27/MWh which is comparable to the Q3 2024 average of $1.36/MWh. The average static inefficiency in Q3 represents 2.5% relative to the average pool price. In recent quarters the value of static inefficiencies as a percentage of pool price has been relatively consistent at between 1.6% and 2.8% (Table 21).

Table 21: Average static inefficiency and average pool price (Q1 2024 to Q3 2025)

	Avg. static inefficiency ($/MWh)	**Avg. pool price ($/MWh)**	**Avg. static inefficiency as a percent of avg. pool price**
Q1 2024	$1.63	$99.30	1.6%
Q2 2024	$0.87	$45.17	1.9%
Q3 2024	$1.36	$55.36	2.5%
Q4 2024	$1.16	$51.52	2.3%
Q1 2025	$0.95	$39.78	2.4%
Q2 2025	$1.13	$40.48	2.8%
Q3 2025	$1.27	$51.29	2.5%

In Q3 static inefficiencies were higher in August and September and lower in July (Figure 27). These differences reflect higher allocative inefficiencies in August and September. The low allocative inefficiencies in July were driven by mild weather conditions and high thermal availability, as these factors prevented the exercise of market power for the majority of hours in the month.

Figure 27: Average static inefficiencies (January 2024 to September 2025)



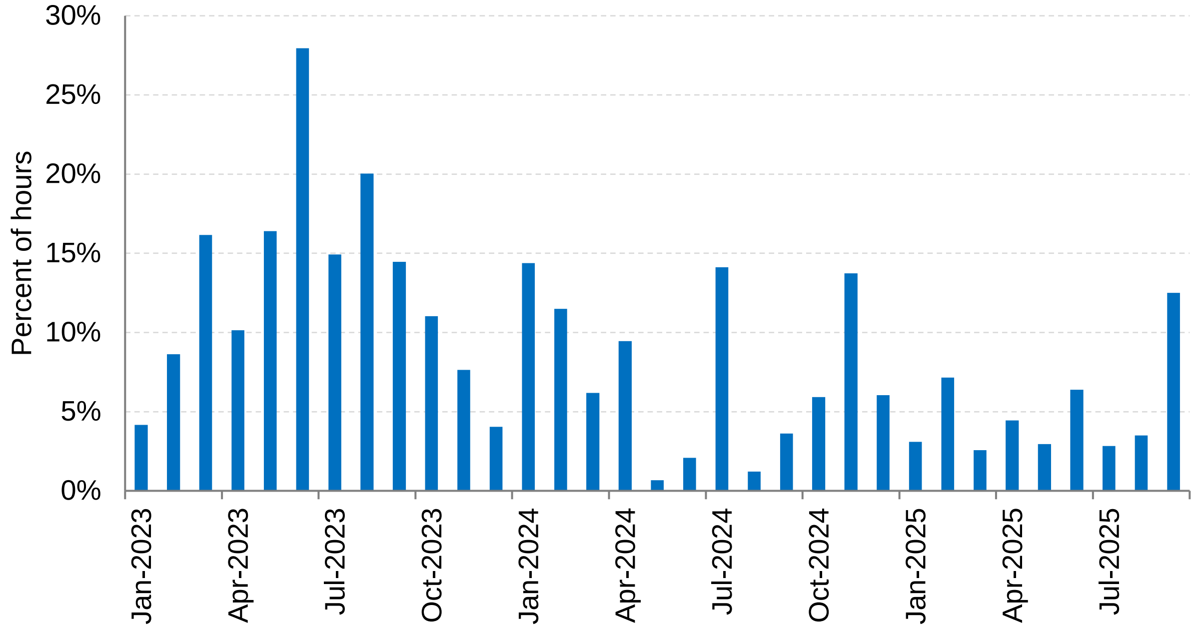
In August, demand was higher as temperatures increased and in September, import capability on BC/MATL was often restricted or unavailable and there were several planned generator outages. In some hours, these factors combined with low intermittent generation to reduce competition in the energy market. Therefore, in August and September there were more hours when market power was exercised by suppliers, resulting in higher allocative inefficiencies.

Despite similar levels of allocative inefficiency in August and September, the ability of firms to exercise market power was markedly higher in September (Figure 28). One way to measure the ability of firms to exercise market power is to calculate how often they are pivotal. A firm is pivotal to the market when its withholdable capacity is needed for the market to clear.[3]

In September, at least one firm was pivotal in 12.5% of hours, the highest value since November 2024. In August, at least one firm was pivotal in 3.5% of hours and in July, the figure was 2.8%. The higher ability of firms to exercise market power in September was driven by restrictions on the supply of imports for much of the month, in addition to some planned generator outages including at HR Milner (300 MW), Mackay River (207 MW), Northern Prairie Power Project (105 MW), and Cloverbar 3 (101 MW).

[3] A firm's withholdable capacity includes all capacity except for intermittent capacity and minimum stable generation.

Figure 28: The percentage of hours in which the largest firm was pivotal (January 2023 to September 2025)



1.4.2 Offer behaviour

The amount of economic withholding in the energy market has declined in recent years as competition has increased with the addition of new gas and intermittent capacity. Figure 29 illustrates the average percentage of non-hydro capacity in the merit order offered above different price levels. The purple line shows that the percentage of non-hydro capacity offered above $250/MWh has decreased over time following peaks in early 2021 and in the summer of 2022 and 2023.

However, market participants continue to exercise market power when market conditions are sufficiently tight, often around the net demand peak in the evening. As shown in Figure 29, the percentage of non-hydro capacity offered above $900/MWh has increased since 2024.

In Q3, the average amount of non-hydro capacity offered above $250/MWh was 760 MW. Within this, only 54 MW was offered between $500/MWh and $750/MWh and only 46 MW was offered between $750/MWh and $900/MWh. A higher proportion, 534 MW, was offered above $900/MWh. Because most of the non-hydro capacity offered above $250/MWh was concentrated at prices above $900/MWh, there were several instances in Q3 where the SMP moved rapidly from low to high levels over short periods during tight supply-demand conditions.

For example, on September 1, the SMP at 21:05 was $120/MWh but this quickly jumped to $925.43/MWh at 21:06, an increase of $805.43/MWh within one minute. The steep supply curve observed during this period was largely the result of offer behaviour (Figure 30).

Figure 29: Percentage of non-hydro capacity in merit order offered above select price levels (January 2021 to September 2025)

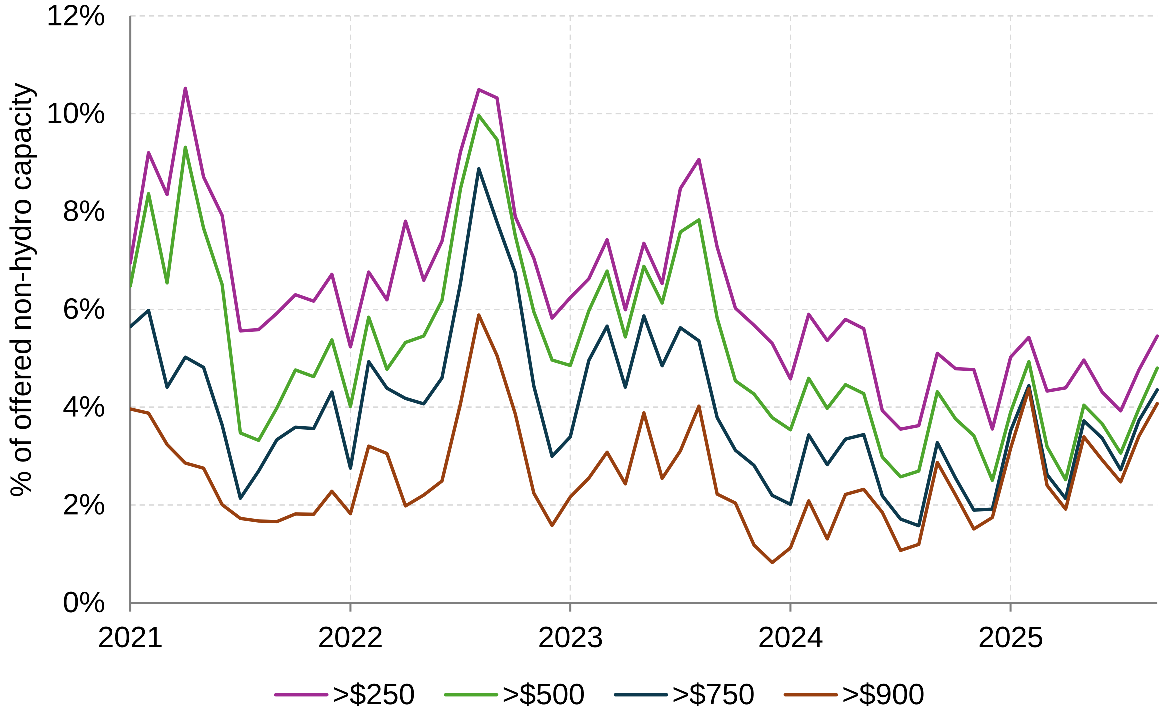
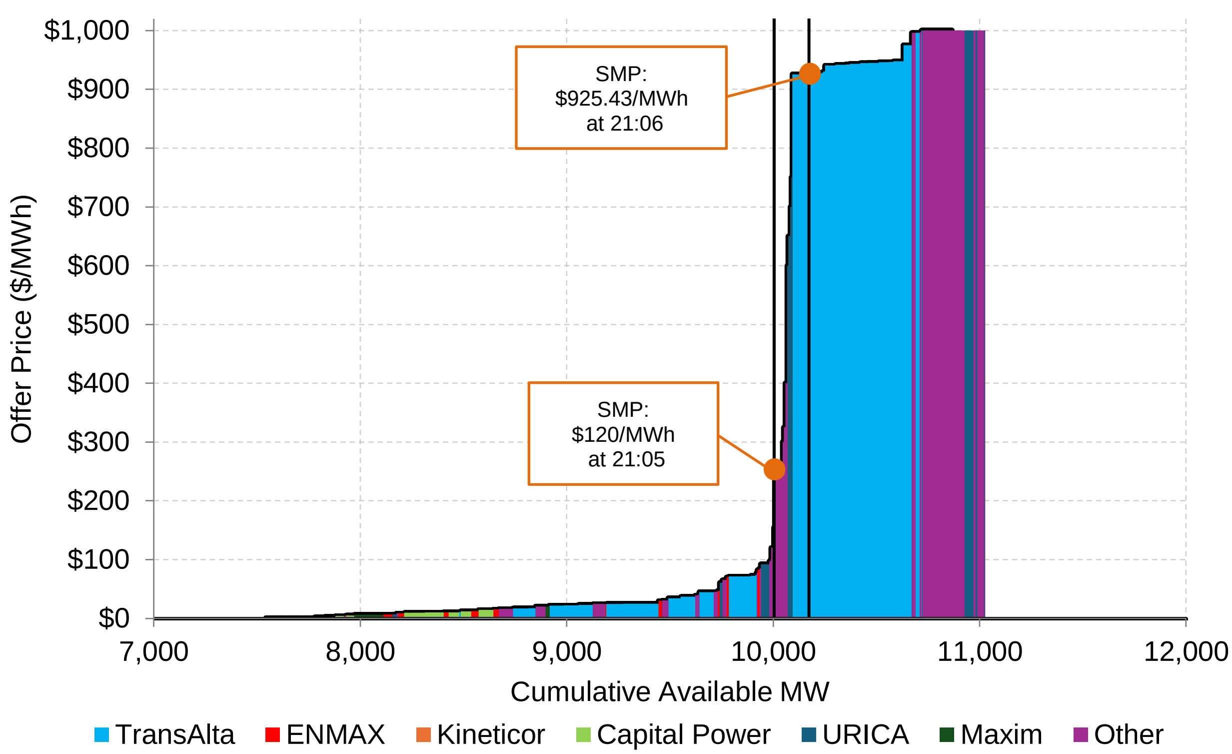


Figure 30: Merit order snapshot (HE 22 of September 1, 2025)



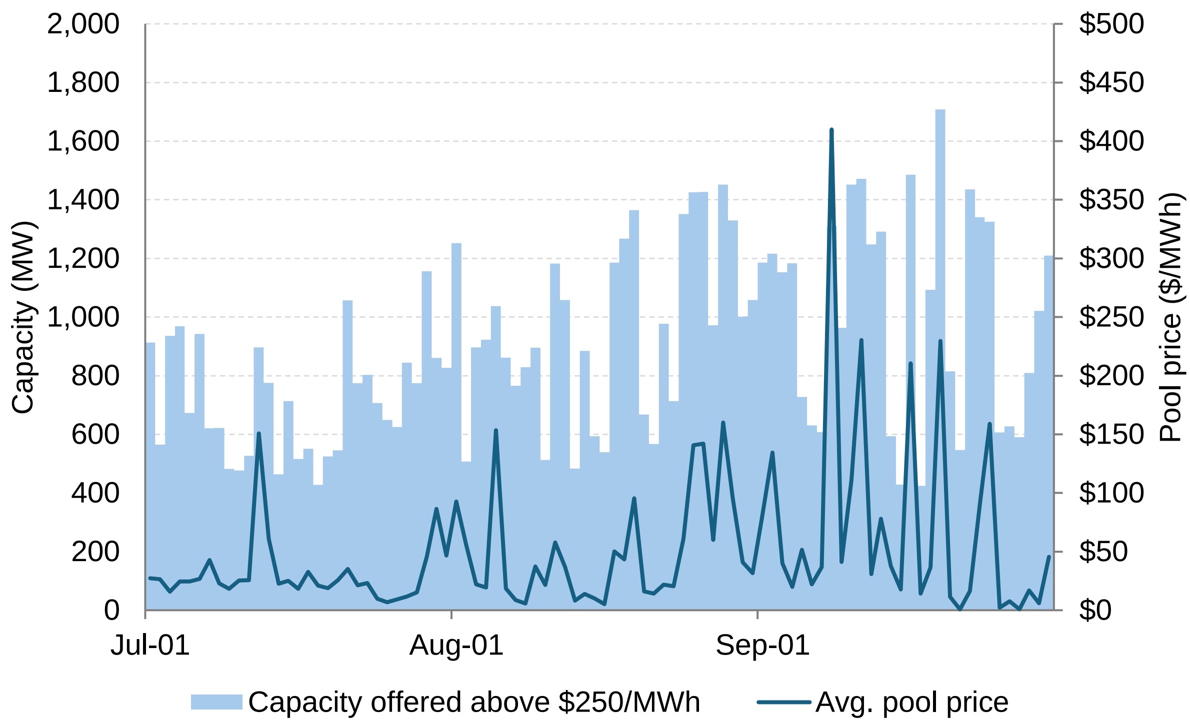
The average amount of non-hydro capacity offered above $250/MWh was highest in September at 853 MW as higher demand year-over-year and reduced import capacity tightened the energy market (Table 22). Similarly, the market conditions in September also saw the lowest average amount of gas-fired steam capacity be taken commercially offline on long lead time at 634 MW.

Figure 31 illustrates the amount of non-hydro capacity offered above $250/MWh during the highest priced hour of each day in Q3. In HE 21 on September 19, 1,700 MW of non-hydro capacity was offered above $250/MWh, the highest in the quarter. As a result of this offer behaviour, the SMP was $940.26/MWh at 20:40 while the supply cushion was 1,100 MW.

Table 22: Average non-hydro capacity offered above $250/MWh and gas-fired steam capacity on LLT – Q3 2025

Month	Avg. non-hydro capacity offered above $250/MWh (MW)	Avg. gas fired steam capacity on LLT (MW)
July	646	1,068
August	783	945
September	853	634

Figure 31: The amount of non-hydro capacity offered above $250/MWh during the highest priced hour of the day (Q3)



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 has relied on information that is publicly available. The results reported here do not include imported generation.[4]

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 23 shows the minimum, mean, and maximum hourly average emission intensity for Q3 over the past seven years. Average emission intensity has fallen significantly over recent years driven primarily by the removal of coal from the system; some coal assets have been converted to natural gas while others have been retired. In addition, there has been a material increase in the supply of intermittent generation.

Notably, the mean hourly average emission intensity for Q3 (0.39 tCO2e/MWh) was close to the minimum hourly average emission intensity for Q3 2022 (0.38 tCO2e/MWh), and the maximum hourly average emission intensity for Q3 (0.51 tCO2e/MWh) is below the minimum hourly average emission intensity for Q3 2019 (0.53 tCO2e/MWh).

Table 24 shows the same summary statistics for the past four quarters, demonstrating stability in the hourly average emission intensity.

Table 23: Year-over-year min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
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
2025 Q3	0.24	0.39	0.51

[4] For more details on the methodology, see the MSA's Quarterly Report for Q4 2021.

Table 24: Quarter over quarter min, mean, and max hourly average emission intensities (tCO_2e/MWh)

Time period	Min	Mean	Max
2024 Q4	0.25	0.40	0.54
2025 Q1	0.27	0.40	0.54
2025 Q2	0.24	0.37	0.54
2025 Q3	0.24	0.39	0.51

Figure 32 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q3 over the past seven years. The decline in carbon intensity over time is demonstrated by the leftward shift of hourly average carbon intensity distributions. Figure 33 illustrates the distribution of the hourly average carbon emission intensity over the past four quarters.

Figure 32: The distribution of average carbon emission intensities in Q3 (2019 to 2025)

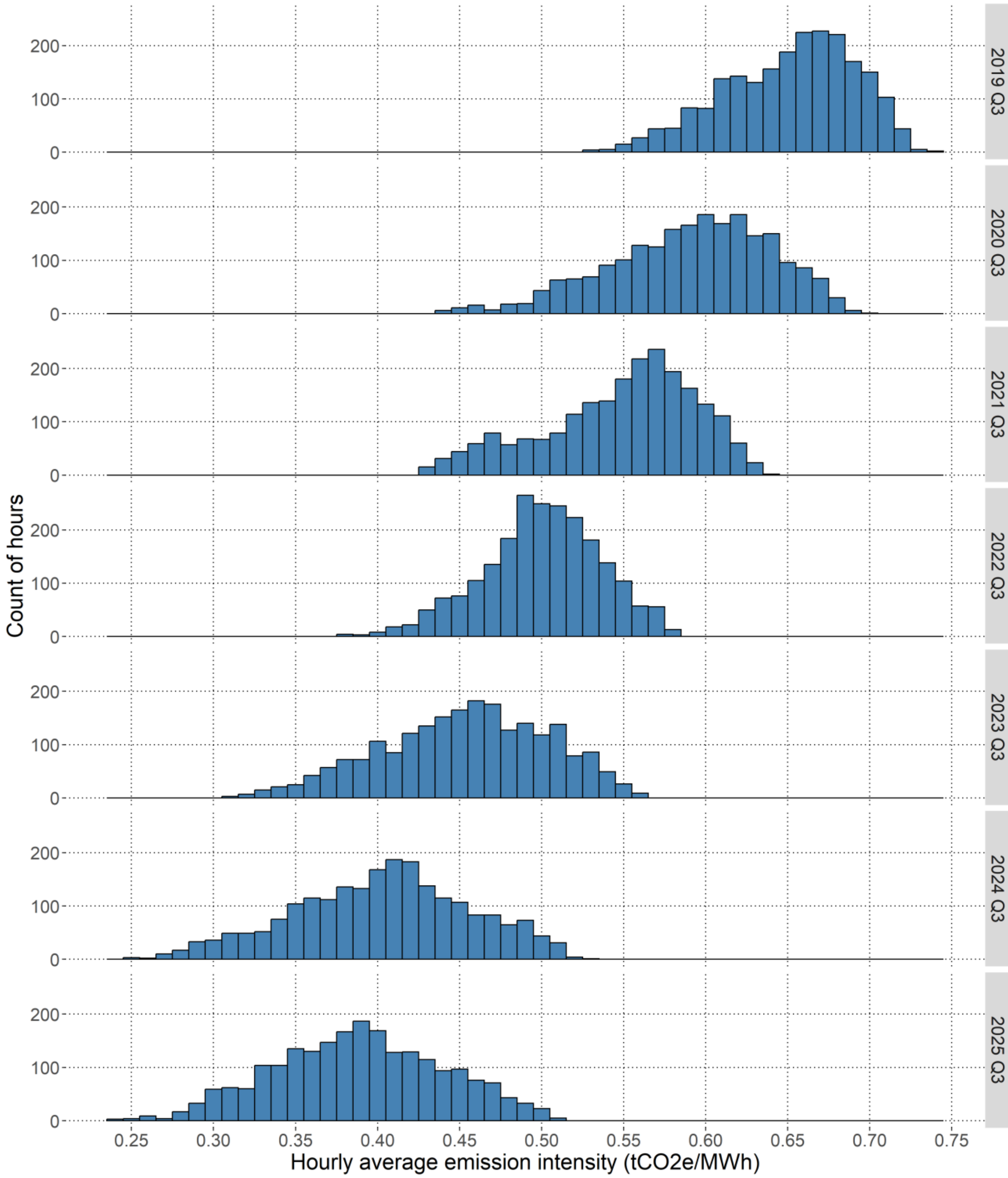
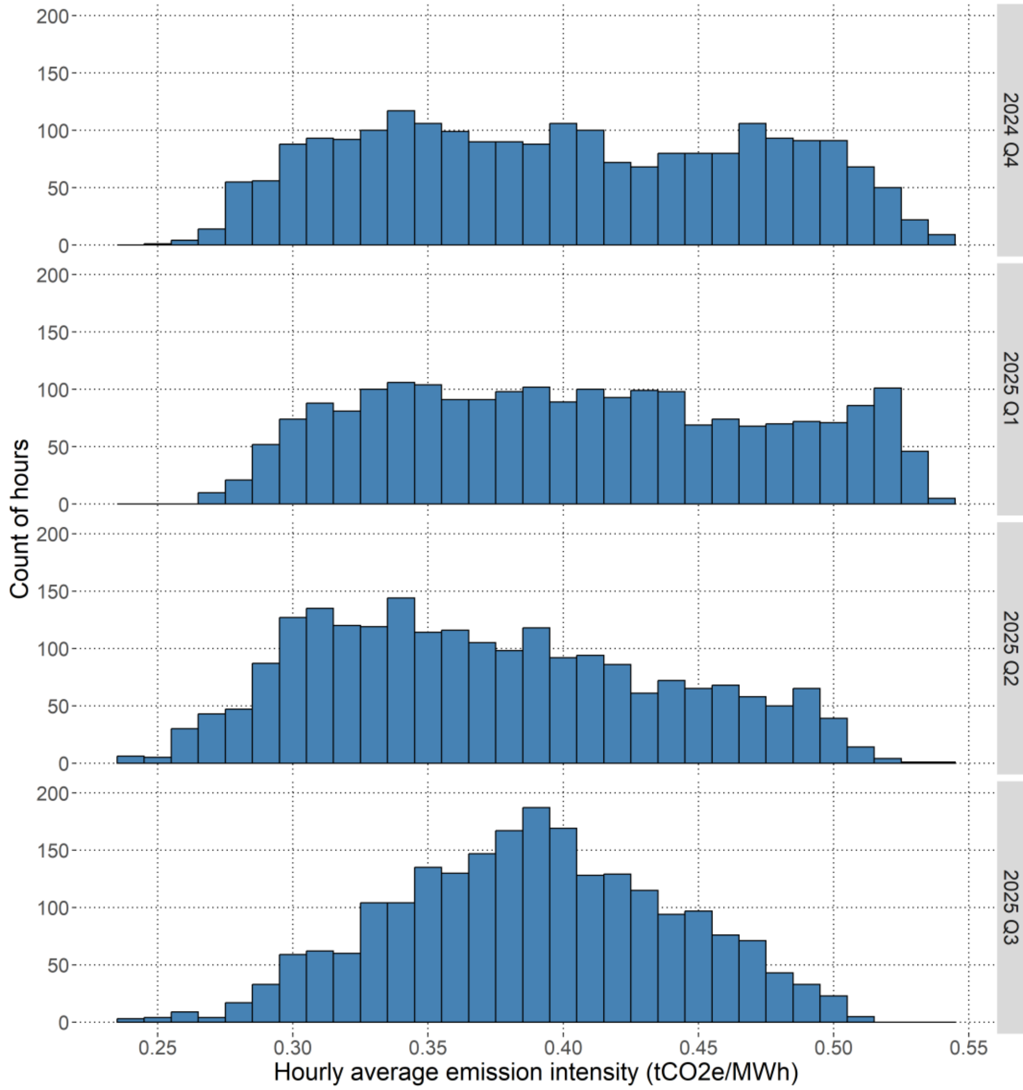
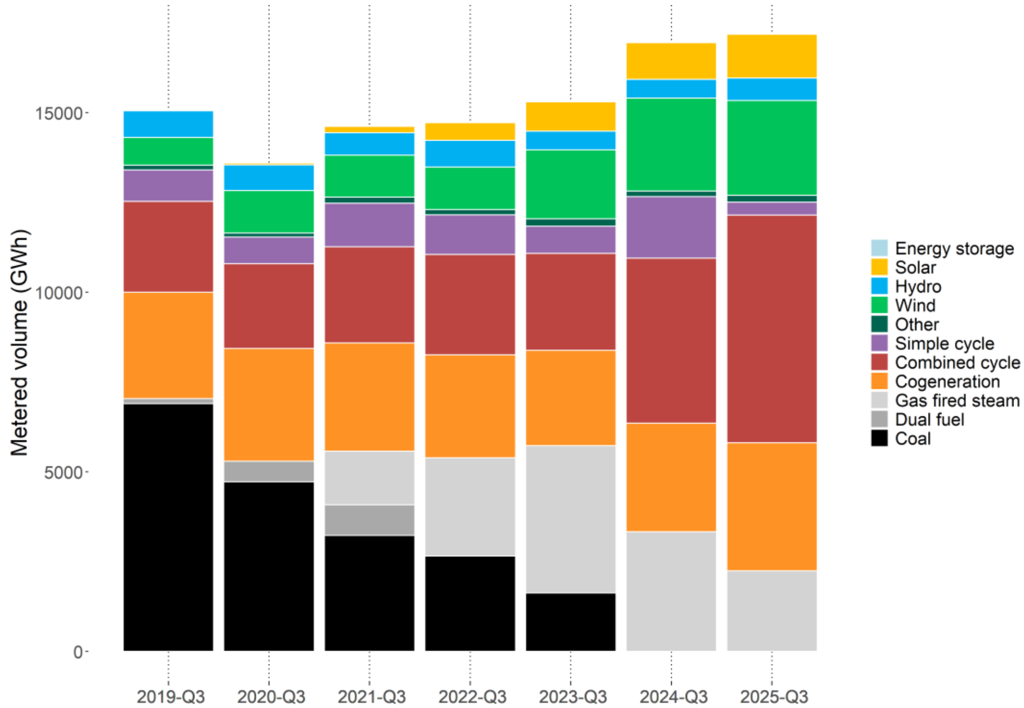


Figure 33: The distribution of average carbon emission intensities in the past four quarters



The leftward shift of the distributions in Figure 32 can be traced to Figure 34, 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 efficient gas assets, including Cascade 1 and 2 and Genesee Repower 1 and 2, has put downward pressure on average carbon intensity more recently.

Figure 34: Quarterly total net-to-grid generation volumes by fuel type for Q3 (2019 to 2025)

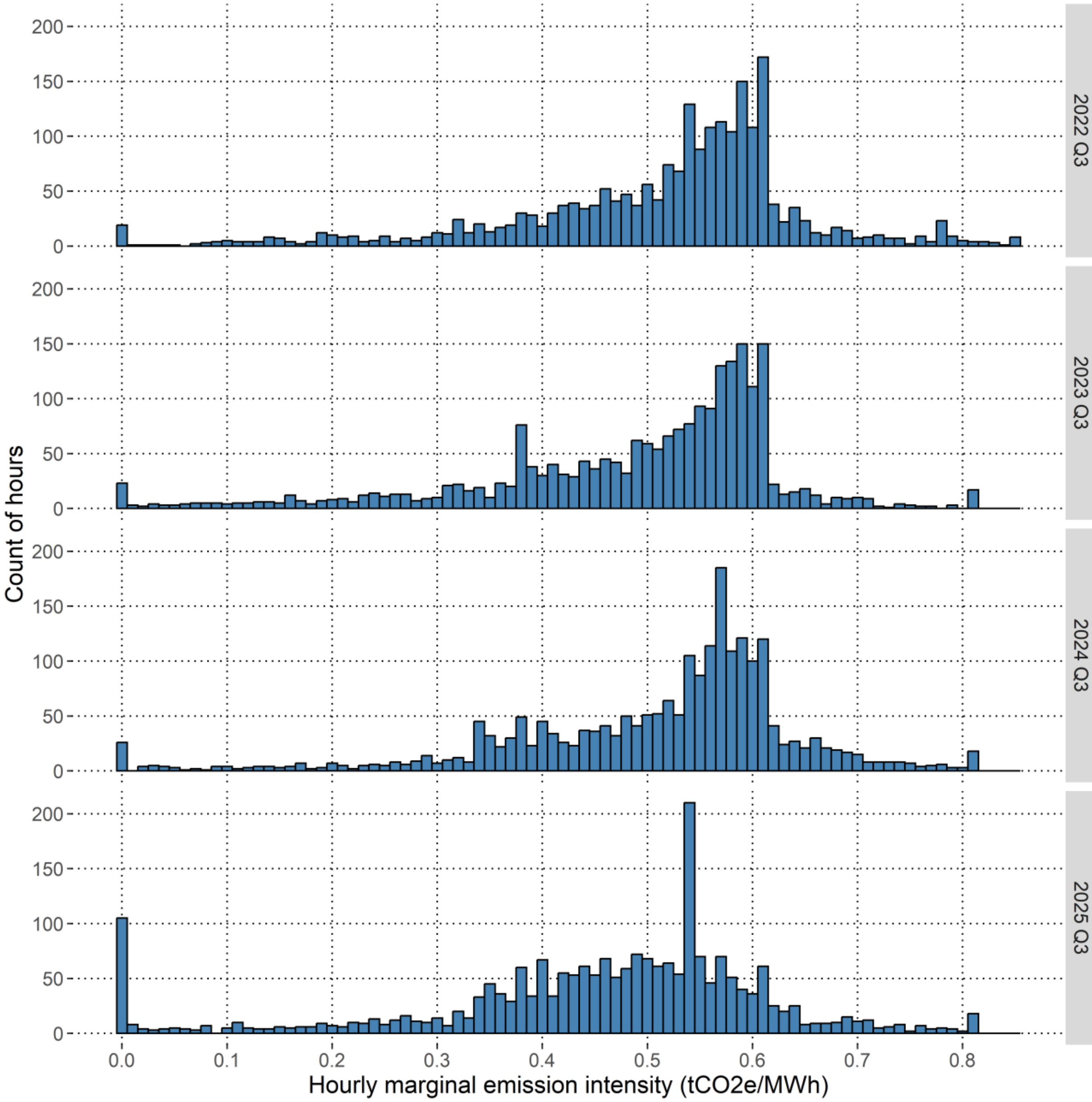


1.5.2 Hourly marginal emission intensity

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 35 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 for these quarters, as demonstrated by the higher observations around 0.54 to 0.60 tCO2e/MWh.

In Q3, gas-fired steam assets were marginal most often at 37% of the time, followed by combined cycle assets at 31%. This is a reversal of what was observed in Q2 when combined cycle assets were marginal 42% of the time, while gas-fired steam assets were marginal 19% of the time. In Q3, assets that are considered having a 0.0 tCO2e/MWh emission intensity were marginal 13% of the time.

Figure 35: The distribution of marginal carbon emission intensities in Q3 (2022 to 2025)



2 THE POWER SYSTEM

2.1 Congestion

Transmission elements may impose limitations to the transfer of electric energy from one location on the transmission system to another. The AESO mitigates these limitations in real time by curtailing generation.[5]

The MSA measures constrained intermittent generation (CIG) volumes, an estimate of the potential generation of an intermittent asset that is curtailed due to a transmission constraint. The CIG calculation uses data on curtailment limits, available capacity, potential real power capability, and energy dispatch.[6]

The frequency and significance of CIG directives increased from Q3 2024 to Q3. The MSA estimates that CIG volumes were 125 GWh in Q3 2024 and 268 GWh in Q3, a 114% increase year-over-year. Quarter-over-quarter, the CIG volumes decreased by 42 GWh.

The maximum hourly average volume of CIG in Q3 was 2,332 MW, over 50% higher than the Q3 2024 maximum of 1,434 MW (Figure 36 to Figure 38). The Q3 maximum hourly average volume of CIG was also higher than the previous quarters maximum value of 1,686 MWh (Figure 37).

The increased CIG volumes in Q3 were likely due to increased intermittent capacity and high intermittent generation. Generally, higher CIG volumes align with periods of high intermittent generation or supply surplus events (Figure 39 and Figure 40).

There were over 353 shift log events for constrained down generation in Q3. Increased constrained intermittent generation volumes may also be due to persistent or frequent limitations to certain transmission elements and may affect one or more generation assets. In Q3 there were a wide variety of events that occurred over many different transmission elements. Q3 saw frequent constraints due to Most Severe Single Contingency (MSSC), where the constraints in respect to MSSC affected the top four most constrained intermittent assets over the quarter.

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[5] This is known as constrained down generation. See ISO Rule 302.1 Transmission Constraint Management.

[6] The AESO's ETS Estimated Cost of Constraint Report calculate TCR volumes using a different methodology than the MSA's estimate of constrained intermittent generation. The MSA's Quarterly Report for Q2 2023 discusses how the MSA calculates the CIG volumes (previously referenced as constrained down volumes).

Figure 36: Maximum hourly transmission constrained intermittent generation (Q3 2024)

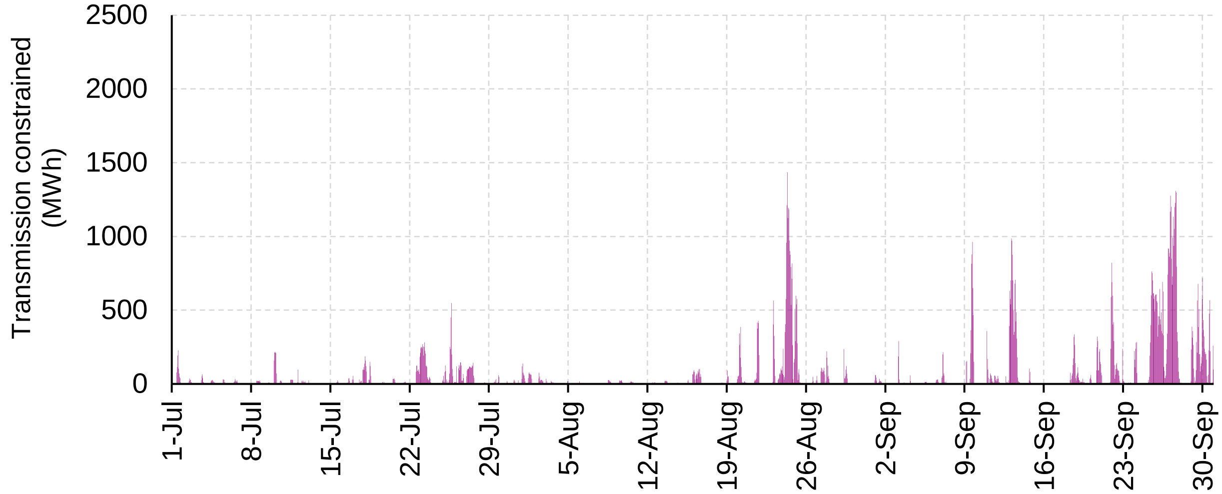


Figure 37: Maximum hourly transmission constrained intermittent generation (Q2 2025)

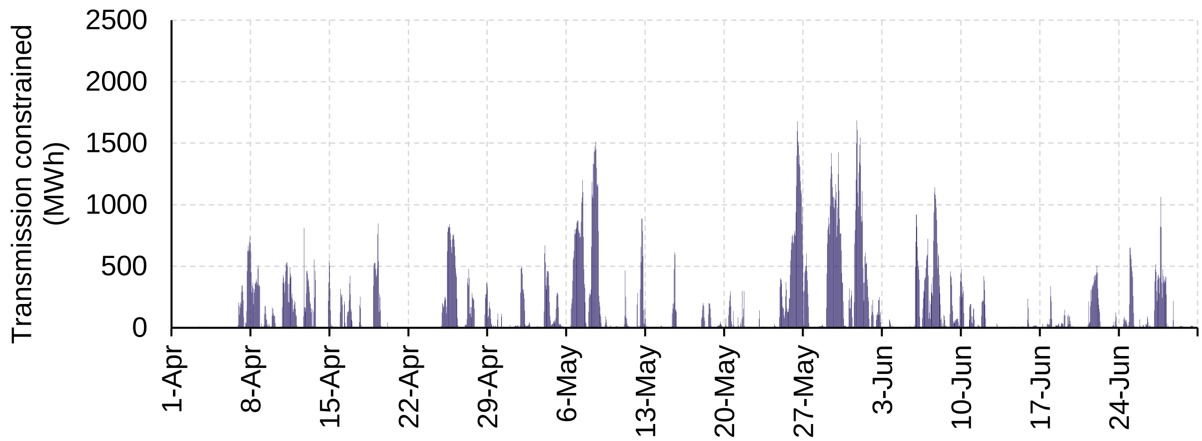


Figure 38: Maximum hourly transmission constrained intermittent generation (Q3 2025)

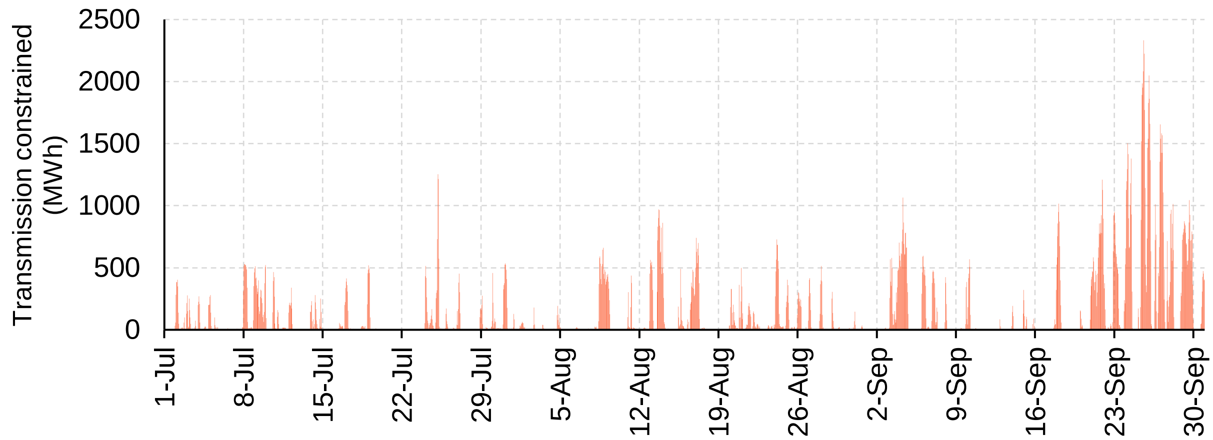


Figure 39: Average hourly intermittent generation and constrained intermittent generation (Q3)

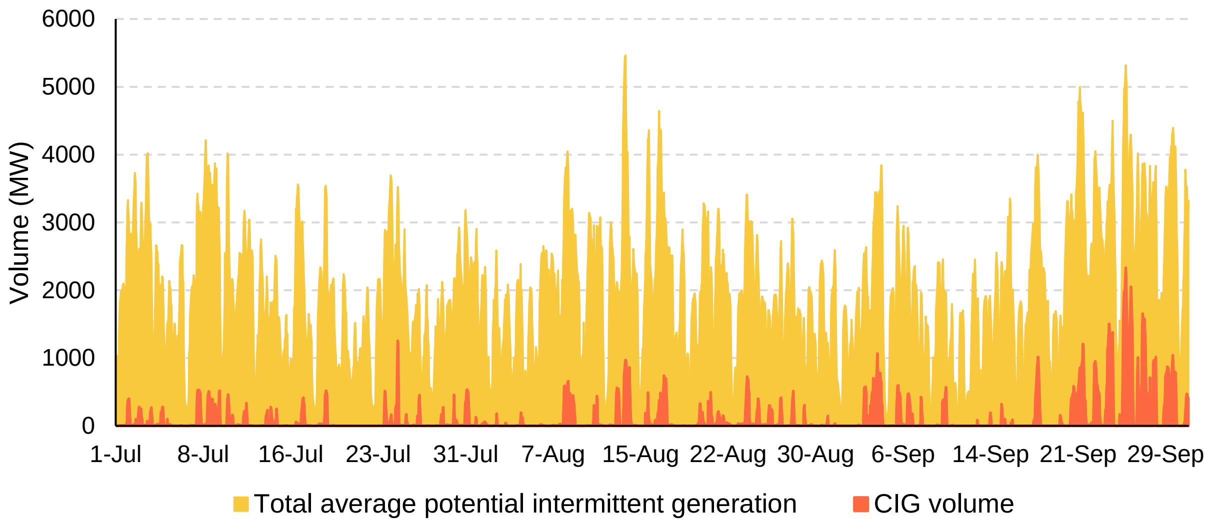
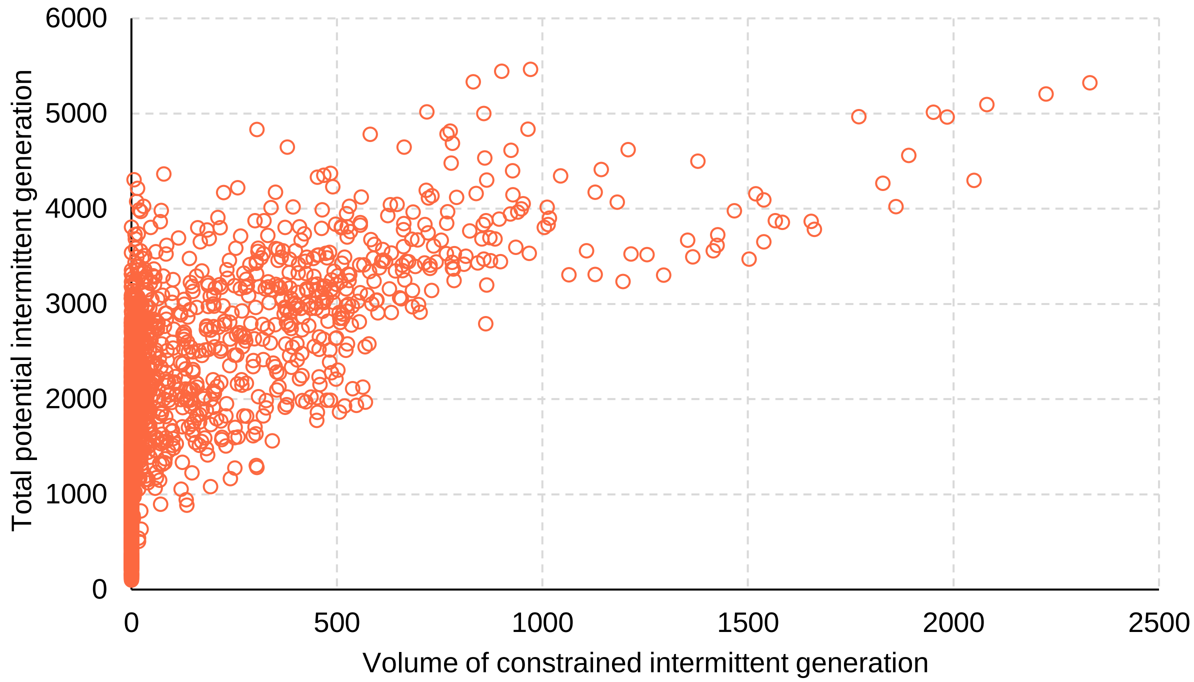


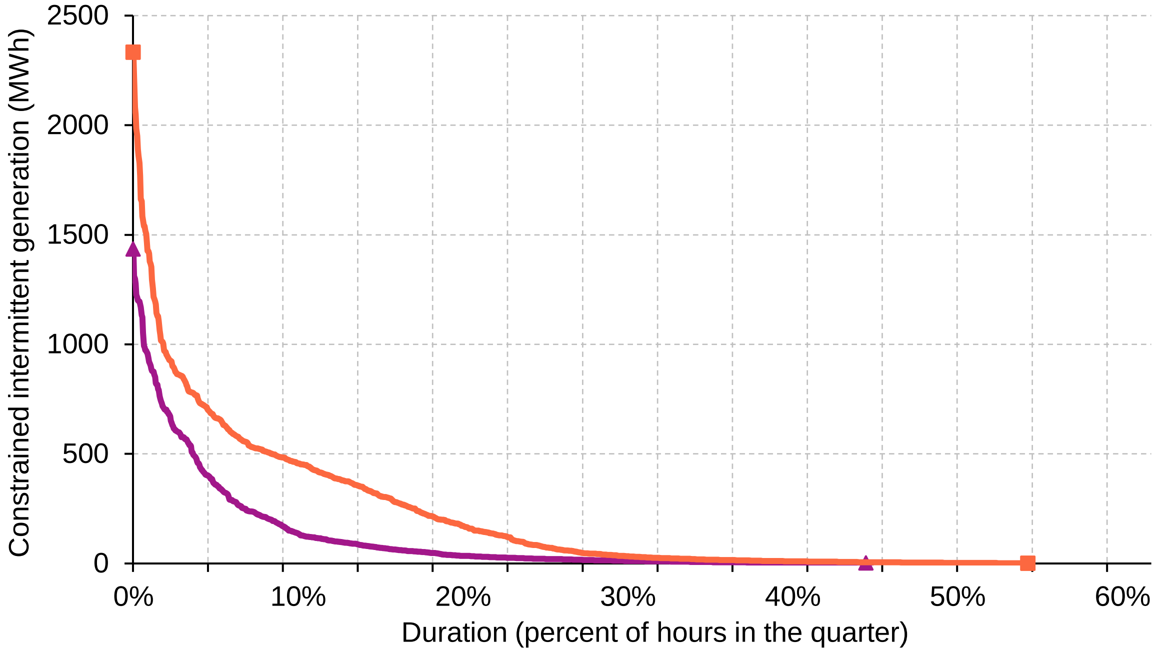
Figure 40: Volume of CIG compared to total potential intermittent generation (Q3)



The increase in CIG volume from Q3 2024 to Q3 occurred at a higher rate than the installation of intermittent generation capacity. While total installed intermittent capacity increased by 8%, average hourly CIG volumes, expressed as a percent of installed intermittent capacity, increased from 0.8% in Q3 2024 to 1.6% in Q3.

Figure 41 illustrates duration curves of CIG year-over-year. The length of the tails to the right of the duration curves show that the frequency of CIG events increased year-over-year. There were 1,197 hours of CIG volumes greater than 1 MWh in Q3. This is equivalent to approximately 50 days, or 54% of Q3. In contrast, Q3 2024 experienced 986 hours of CIG volumes greater than 1 MWh, or over 41 days, or 45% of Q3 2024.

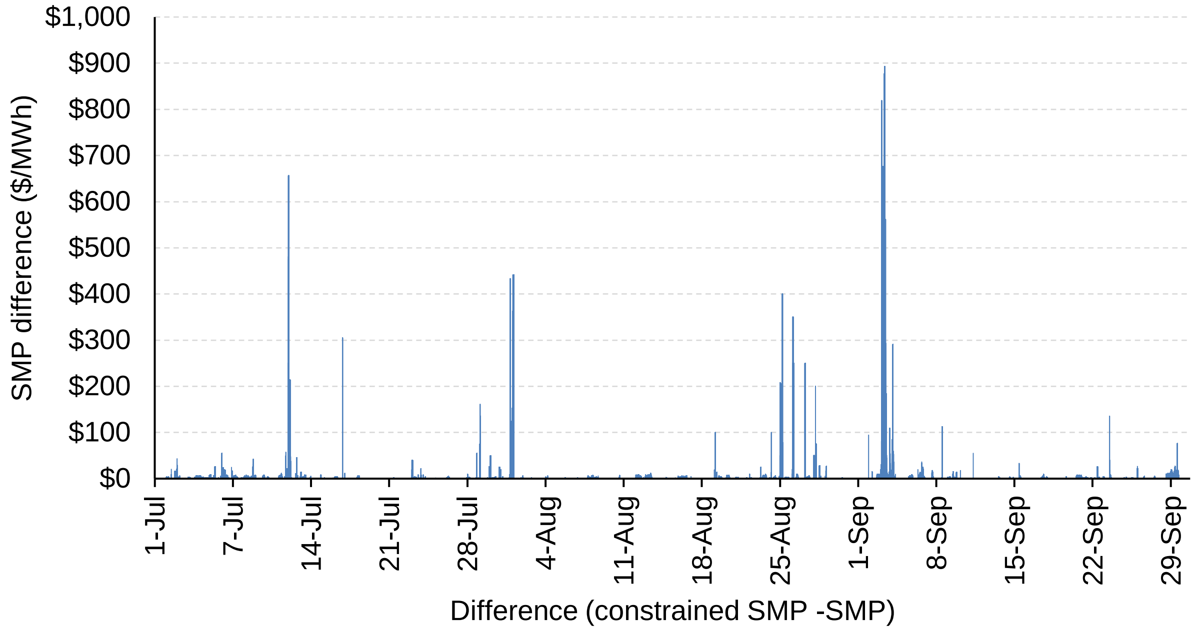
Figure 41: Duration curves of CIG volume (Q3 2024 and Q3)



Transmission constraint volumes had frequent fluctuations throughout all months of Q3, however September experienced the most volume of CIG and the highest peak. The CIG volume in the month of September accounted for 60% of all Q3 volumes. In 51% of September hours there was at least 1 MWh of CIG.

The constrained and unconstrained SMP differed by $1/MWh or more in 20% of minutes in Q3 (Figure 42). In comparison, Q3 2024 experienced 19% of minutes with a variance of $1/MWh or more in the constrained SMP and unconstrained SMP, and Q2 2025 experienced the difference in 25% of minutes. The largest difference between the constrained SMP and unconstrained SMP in Q3 was $893/MWh, which occurred in HE20 September 3. The largest difference in unconstrained and constrained SMP was lower in Q3 2024 at $391/MWh. The largest difference in SMP in Q2 2025 occurred on May 26 and reached $981/MWh.

Figure 42: Difference of constrained SMP and unconstrained SMP (Q3)



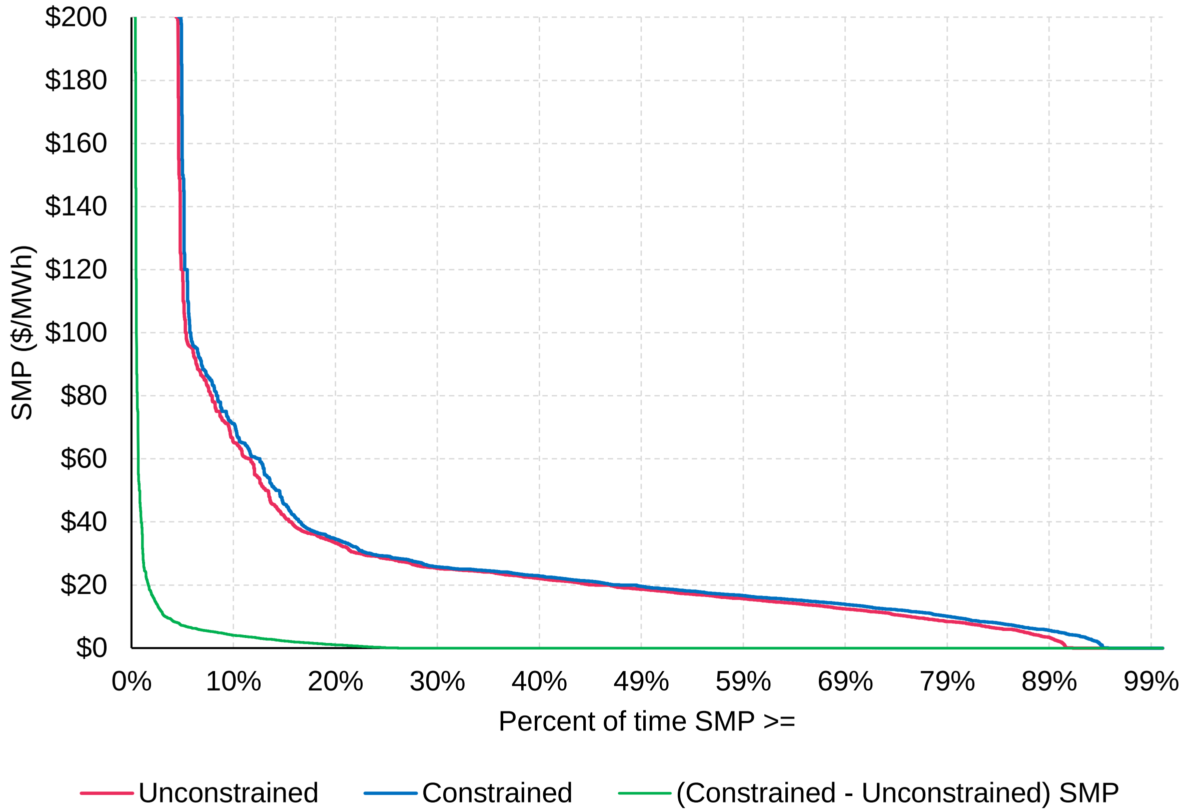
The periods that experience high volumes of CIG often occur when generation from intermittent resources is high. Given the offer behaviour of these resources, when intermittent generation is higher, SMP is lower as higher priced generation is displaced. Therefore, despite the high amount of CIG volumes in Q3, there was often only a small difference between the constrained SMP and the unconstrained SMP (Figure 43). This occurs because when prices are low the supply curve is normally relatively flat, meaning that large changes in quantity will have a relatively small impact on prices.

The two notable spikes in the difference between the constrained and unconstrained SMP exceeded $500/MWh occurred on July 12 and September 3. These two days accounted for 8 GWh or 3% constrained intermittent generation for Q3.

The constraints present on September 3 effected 31 intermittent assets over the day. Sharp Hill Wind (1,103 MWh CIG volume on September 3) was the most constrained asset, followed by Grizzly Bear (748 MWh CIG volume on September 3) and Paintearth Wind Project (710 MWh CIG volume on September 3).

On July 12, the difference between the constrained and unconstrained reached $656/MWh in HE 22 and 11 intermittent assets has positive CIG over the period. The most constrained asset was Forty Mile Bow Island (375 MWh CIG volume on July 12), followed by Cypress 1 (371 MWh CIG volume on July 12) and Whitla 2 (275 MWh CIG volume on July 12). All three assets were constrained due to RAS 164 trip logic 2 arming over MSSC, a frequent constraint over the quarter.

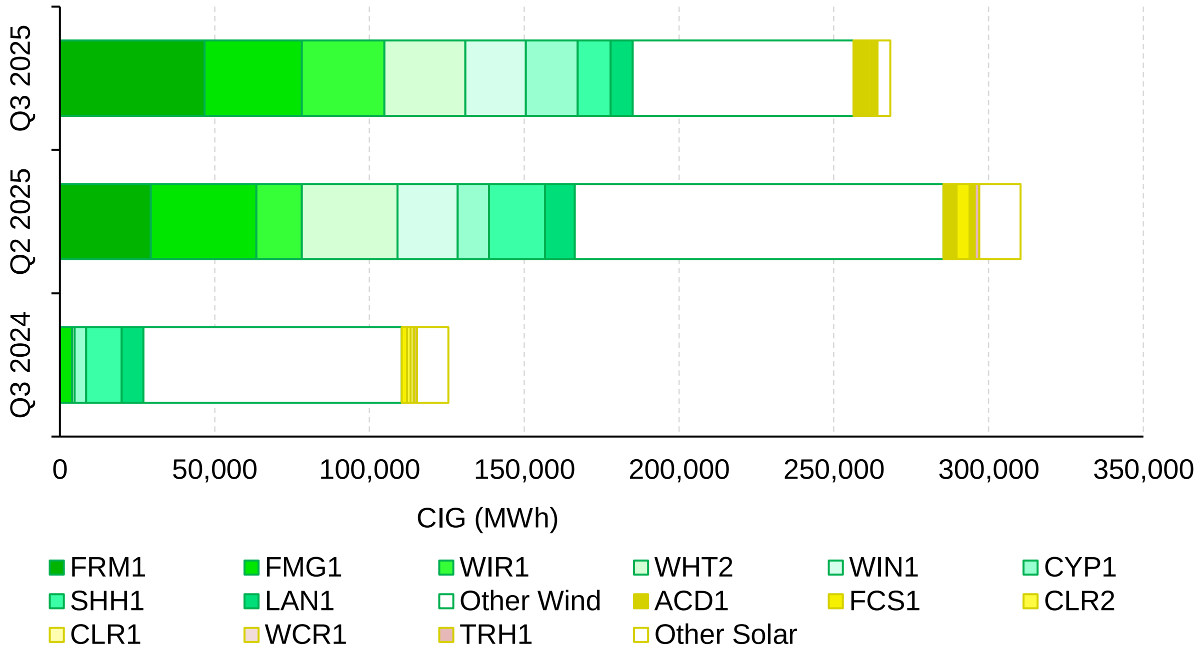
Figure 43: Duration of unconstrained SMP, constrained SMP, and difference between constrained and unconstrained SMP (Q3)



Transmission capability varies throughout the province, and certain regions experience more congestion than others, often leading to local constraints (Figure 44). Often, wind and solar assets are not constrained uniformly throughout the province. In Q3, the eight most constrained wind assets accounted for 72% of the total CIG volume but only 28% of total installed wind generation. Forty Mile Bow Island, Forty Mile Granlea, and Wild Rose were the most constrained wind assets in Q3. These 3 assets represent 15% of Alberta's installed wind capacity, however they accounted for approximately 39% of the wind CIG volume in Q3.

Big Sky Solar (140 MW) was the most-constrained solar asset in Q3, with a total of 4,901 MWh constrained. The asset was constrained due a N-1 contingency on 7L760 which occurred in all months within the quarter. The following five most constrained solar assets have an aggregate maximum capability of 288 MW and were constrained by 2,810 MWh in Q3. The top six constrained solar assets account for 23% of the maximum capability of the market and accounted for 65% of solar CIG volumes in Q3. The uneven distribution of congestion volumes to intermittent assets continues within Alberta.

Figure 44: Wind and solar CIG by asset (Q3 2024, Q2 2025, Q3)



2.2 Interties

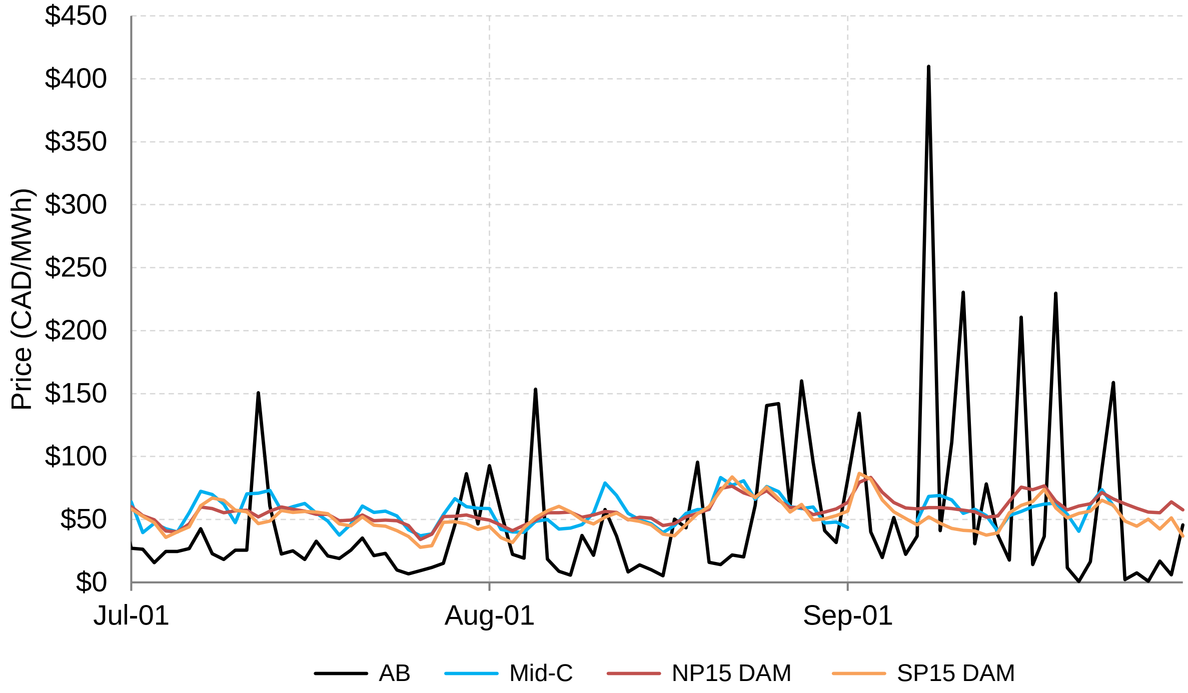
Interties connect Alberta's electricity grid directly to those in British Columbia (BC), Saskatchewan (SK), and Montana (MATL), with the intertie to BC being the largest. The AESO manages the BC intertie and MATL as one shared flow gate (BC/MATL) because any trip on the BC intertie results in a direct transfer trip to MATL. These interties indirectly link Alberta's electricity market to the Mid-Columbia (Mid-C) trading hub and California markets.

Figure 45 shows daily average power prices over Q3 in Alberta, Mid-C, and at NP15 and SP15 in California (all shown in CAD). Over the quarter, Alberta pool prices averaged $51.29/MWh while Mid-C,[7] NP15, and SP15 averaged $56.13/MWh, $56.91/MWh, and $52.26/MWh, respectively. Pool price volatility in Alberta resulted in the quarterly average being comparable to these other markets, however prices were often lower in Alberta. For example, Alberta pool prices were lower than prices in Mid-C in 89% of hours over the quarter.

Alberta pool prices were low in July, lower than Mid-C prices in 95% of hours over the month. As a result, July saw the highest volume of net exports from Alberta since January. Periods of pool price volatility in August resulted in the average pool price nearing prices in other markets. In September pool price volatility pushed average prices in Alberta at least $10/MWh higher. However, a planned outage on BC/MATL islanded Alberta for much of the back half of September.

[7] Mid-C price data is unavailable for the first week of September, the associated periods are removed from applicable calculations.

Figure 45: Daily average power prices in Alberta, Mid-C, and NP15/SP15 in California (Q3)



There were several derates/outages on the interties over the quarter, which can be observed in Figure 46 and are described below:

- From July 21 to 31, BC/MATL import capability was derated to between 160 MW to 310 MW due to an unplanned outage on 2L294, which is transmission internal to southeastern BC.

- From September 8 to 18, BC/MATL import capability was derated to between 20 to 200 MW due to a scheduled outage on 5L92, transmission internal to southeastern BC that feeds the Path 1 intertie (5L94, 1L274, and 1L275).

- Beginning on September 19, a planned outage commenced on the BC intertie, resulting in the islanding of Alberta until the evening of September 28, when the BC intertie returned to service. MATL returned to service the following morning on September 29.

As pool prices in Alberta were often lower than prices in other markets, Alberta continued to be a strong exporter of power in Q3. Alberta exported 352 MW on average over the quarter (Table 25), reaching 505 MW on average in July (630 MW during off-peak hours and 442 MW during peak hours).

Alberta was exporting in 78% of hours of the quarter and importing in 11% of hours. In the remaining 11% of hours the net interchange was flat, which was largely associated with the planned BC/MATL outage in late September.

In comparison to Q3 2024, there were more exports to BC and Montana in Q3 with no imports from the Saskatchewan intertie, which was unavailable this quarter (Table 25). The Saskatchewan intertie returned to commercial operation on October 29.

Figure 46: Daily average import and export scheduled volumes on BC/MATL, joint capability, and Alberta - Mid-C differential (Q3)

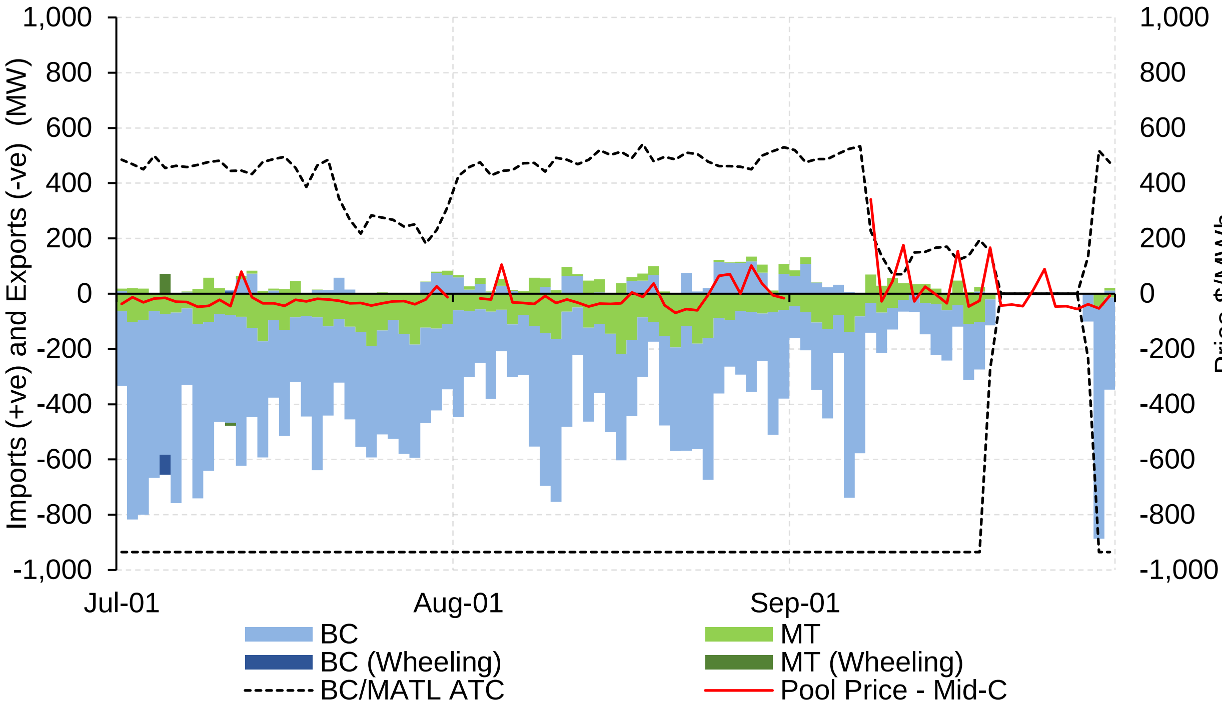


Table 25: Average net import (+ve) and export (-ve) volumes (Q3 and Q3 2024)

	2024				2025			
	BC	**MATL**	**SK**	**Total**	**BC**	**MATL**	**SK**	**Total**
Jul	-167	-39	22	-185	-409	-96	-	-505
Aug	-362	-64	9	-418	-278	-89	-	-367
Sep	-215	-37	19	-233	-150	-29	-	-179
Q3	**-249**	**-47**	**17**	**-278**	**-280**	**-72**	**-**	**-352**

Figure 47 and Figure 48 show the monthly average scheduled interchange on BC and MATL by the five most active participants from July 2024 through September 2025. On the BC intertie there were three main participants in Q3. The largest market participant was exporting to serve domestic load, while the other two participants were largely exporting to US utilities or market hubs. There were also three main participants on MATL over the quarter, the largest serving US utilities, while the other two were largely exporting to industrial loads.

Figure 47: Monthly average scheduled interchange on BC by top five participants (July 2024 to September 2025)

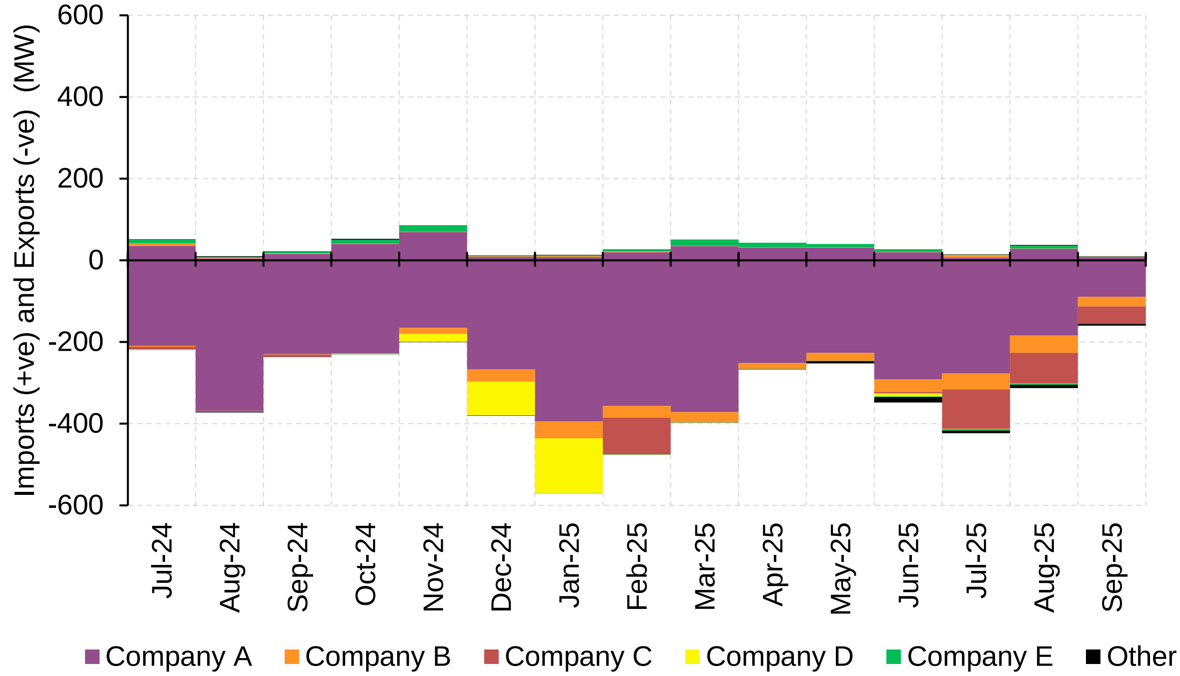


Figure 48: Monthly average scheduled interchange on MATL by top five participants (July 2024 through September 2025)

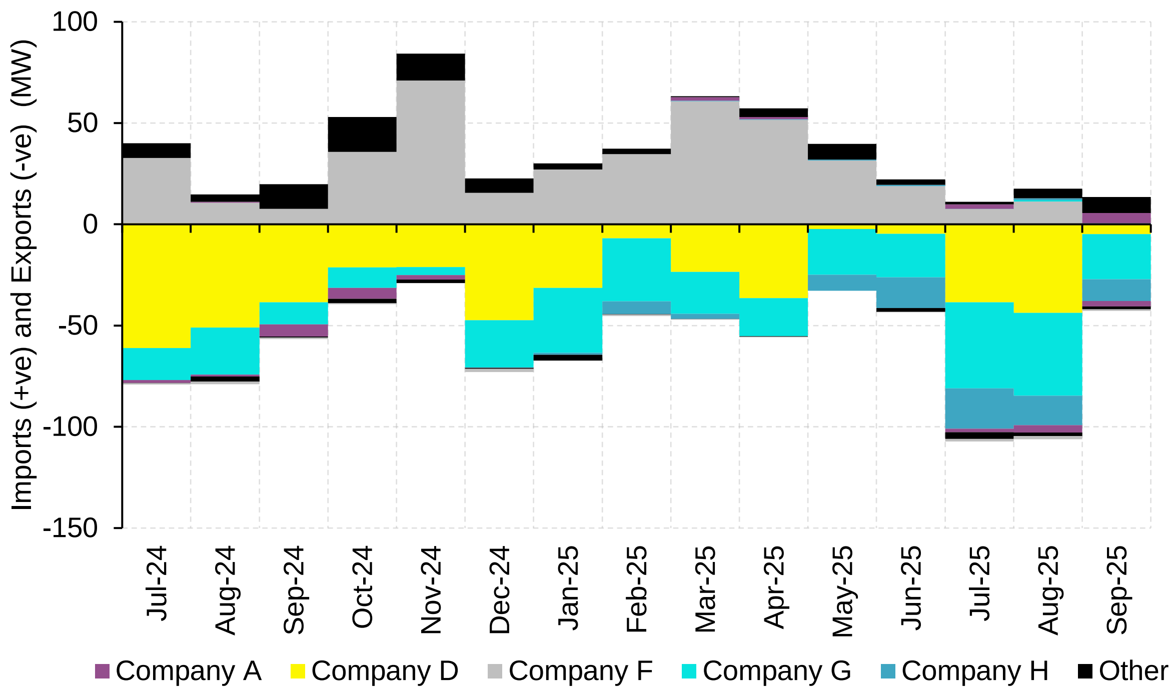


Figure 49 shows a scatterplot of the pool price Mid-C price differential against the net scheduled volume on BC/MATL for each hour of the quarter. Over Q3 there were many hours where export bids or scheduled volumes were at or above BC/MATL export capability, meaning that BC/MATL was export constrained (shown in green). BC/MATL exports were constrained for 226 hours or 10% of the time. While BC/MATL was export constrained, the price differential between Alberta and Mid-C averaged negative $35/MWh and joint export capability averaged 935 MW. Export constrained observations generally lie on the left-hand side of the figure. Reasons for this not being the case include insufficient transmission and curtailments.

There were also hours where net import offers or scheduled volumes on BC/MATL were at or above import capability, meaning that BC/MATL was import constrained (shown in red). BC/MATL imports were constrained for 104 hours in Q3 or 5% of the time. While import constrained, the price differential between Alberta and Mid-C averaged $279/MWh and import capability averaged 240 MW. Hours where import were constrained below 200 MW are associated with the periods of import capability derates over July and September.

Figure 49: Alberta and Mid-C price differential and net BC/MATL schedule (Q3)

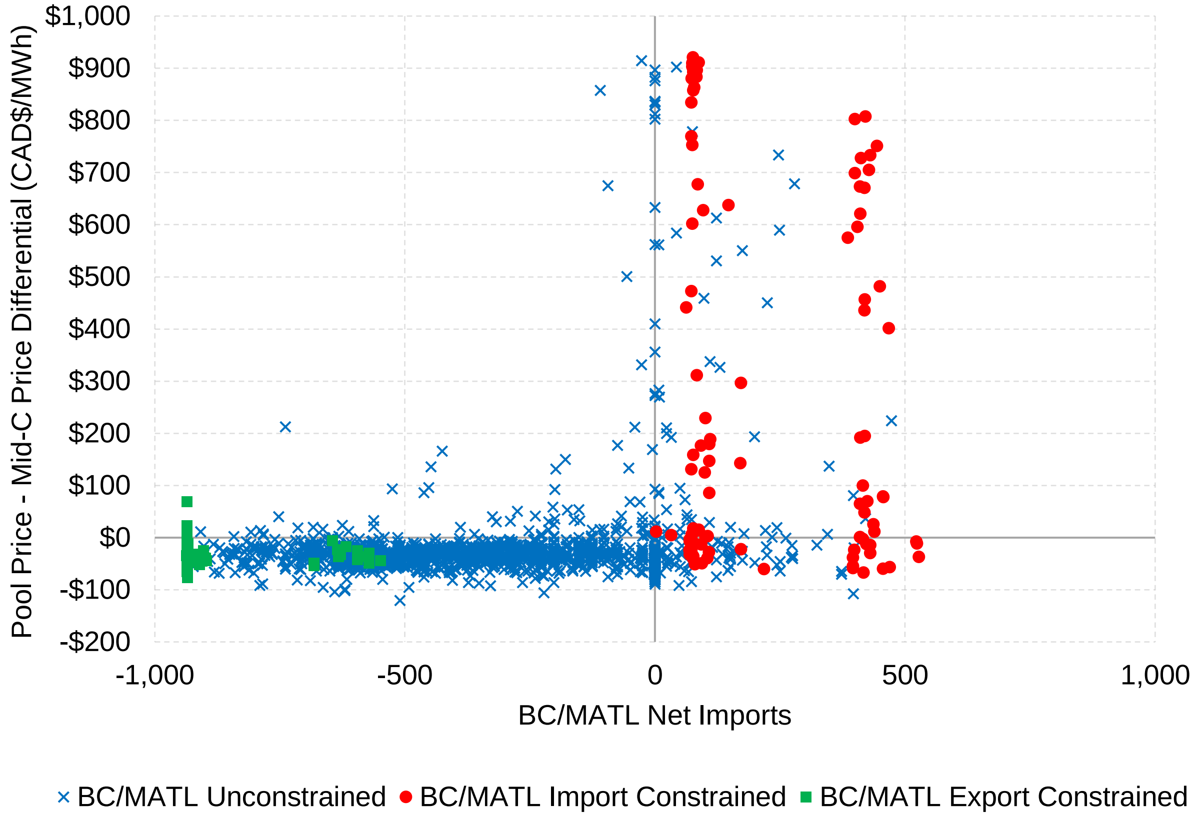
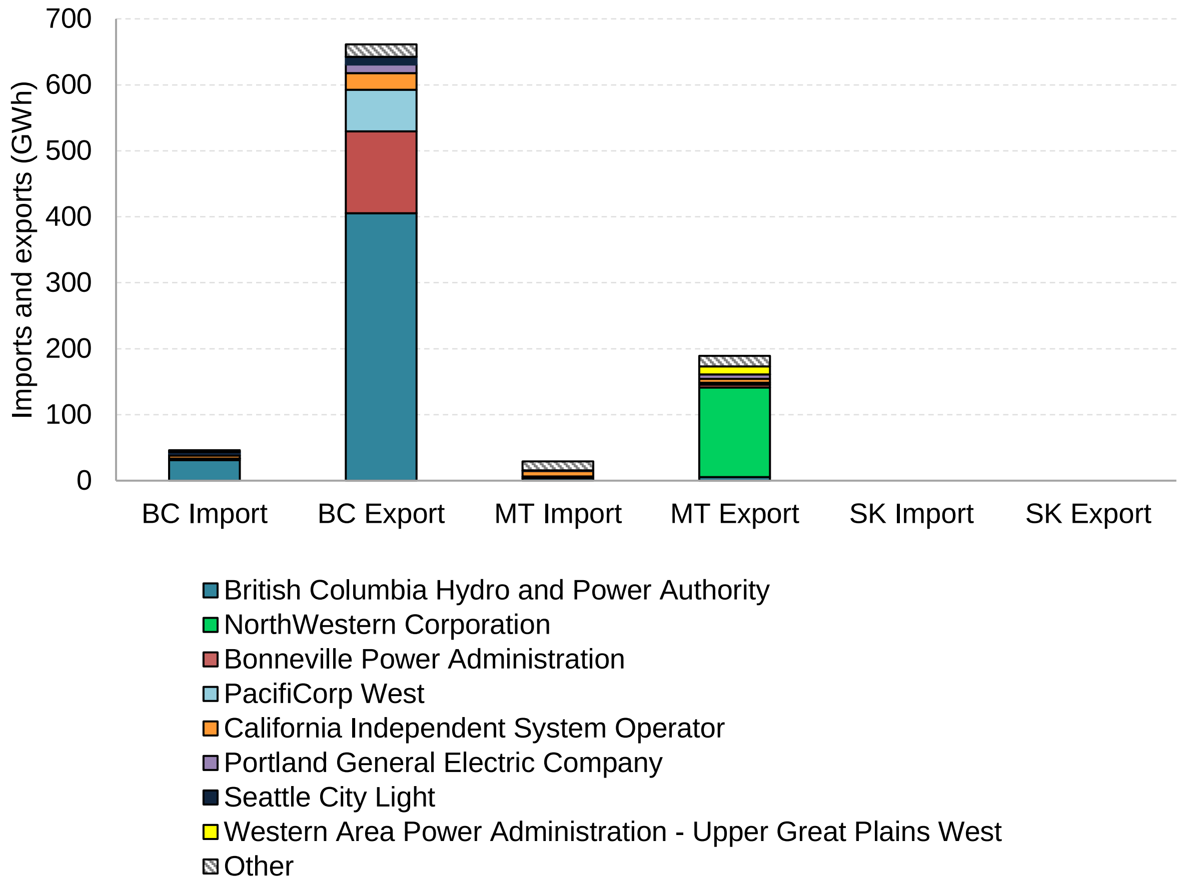


Figure 50 shows import volumes in the quarter by the point of receipt (POR) and export volumes by the point of delivery (POD).[8] The Balancing Authority regions directly connected with Alberta have a high share of import and export flows.

For imports on the BC intertie, approximately 68% originated from BC, 22% from the US Northwest, and 9% from California. For exports on the BC intertie, 61% was delivered to BC, 35% to the US Northwest, and 4% to California. For delivery to the US Northwest, most of the volume was delivered to utilities or to Mid-C hubs. For delivery to California the majority was to SP15.

For imports on MATL, 57% originated from the US Northwest, 29% from California, 13% from BC, and 2% from US Central. For exports on MATL 93% was delivered to the US Northwest, 3% to BC, 3% to California, and 1% to US Central. For delivery to the US Northwest, the majority was to serve utilities or industrial loads. For delivery to California, the majority was to SP15.

Figure 50: Interchange point of receipt (imports) and point of delivery (exports) for interchange volumes by Balancing Authority (Q3)[9]



[8] 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.

[9] This includes the highest eight Balancing Authorities by volume.

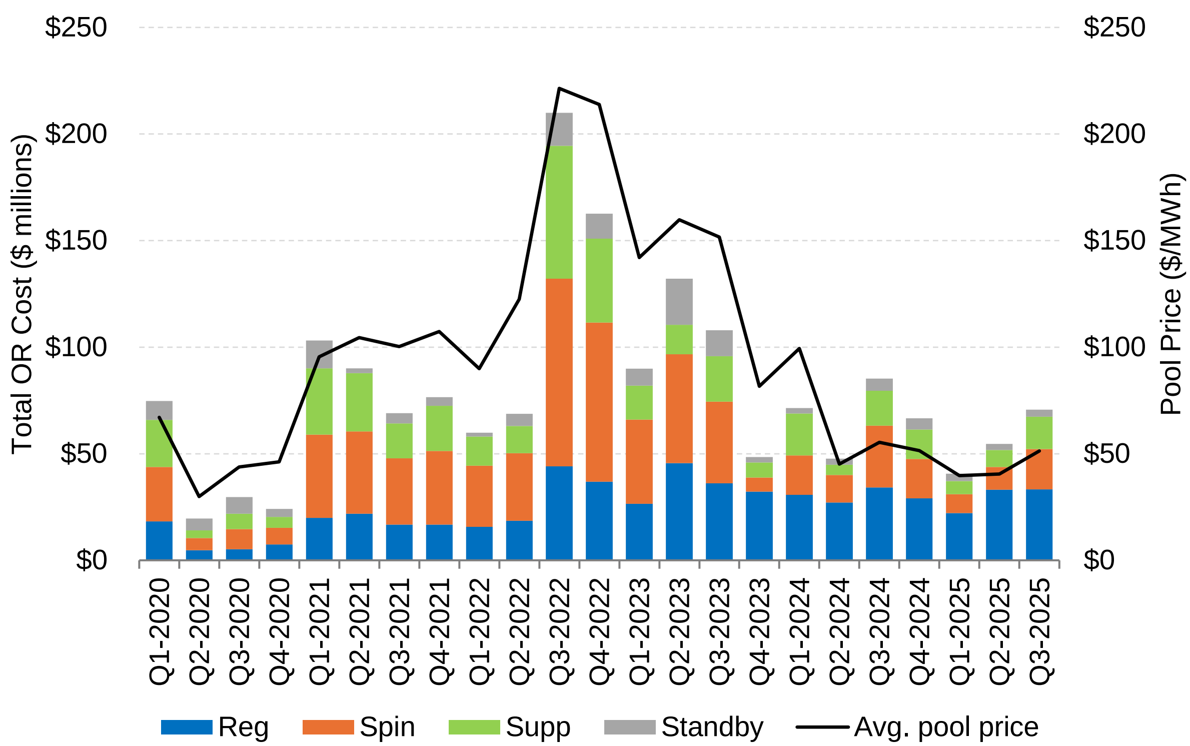
3 OPERATING RESERVES

AESO system controllers call upon three types of operating reserve (OR) to address unexpected imbalances or lagged responses between supply and demand: regulating reserve, spinning reserve, and supplemental reserve. Regulating reserve provides an automatic and instantaneous response to small imbalances 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 large and 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 OR through day-ahead auctions.

3.1 Total costs

The total cost of OR in Q3 was $70.6 million which is a 17% decline compared to Q3 last year but is a 29% increase compared to Q2 (Figure 51). The higher OR costs in Q3 relative to Q2 were partly driven by higher pool prices as the total costs of spinning and supplemental reserves increased by 78% and 90%, respectively. However, the total cost of regulating reserves only increased by 1% quarter-over-quarter as competition in the regulating reserve markets increased.

Figure 51: Total OR cost by product (Q1 2020 to Q3 2025)



As outlined in section 1.2, the AESO procured more regulating reserves and FFR during the BC/MATL outage in late September. The AESO procured more regulating reserves to help deal with the higher routine variation in system frequency and more FFR to increase the domestic frequency response to contingency events.

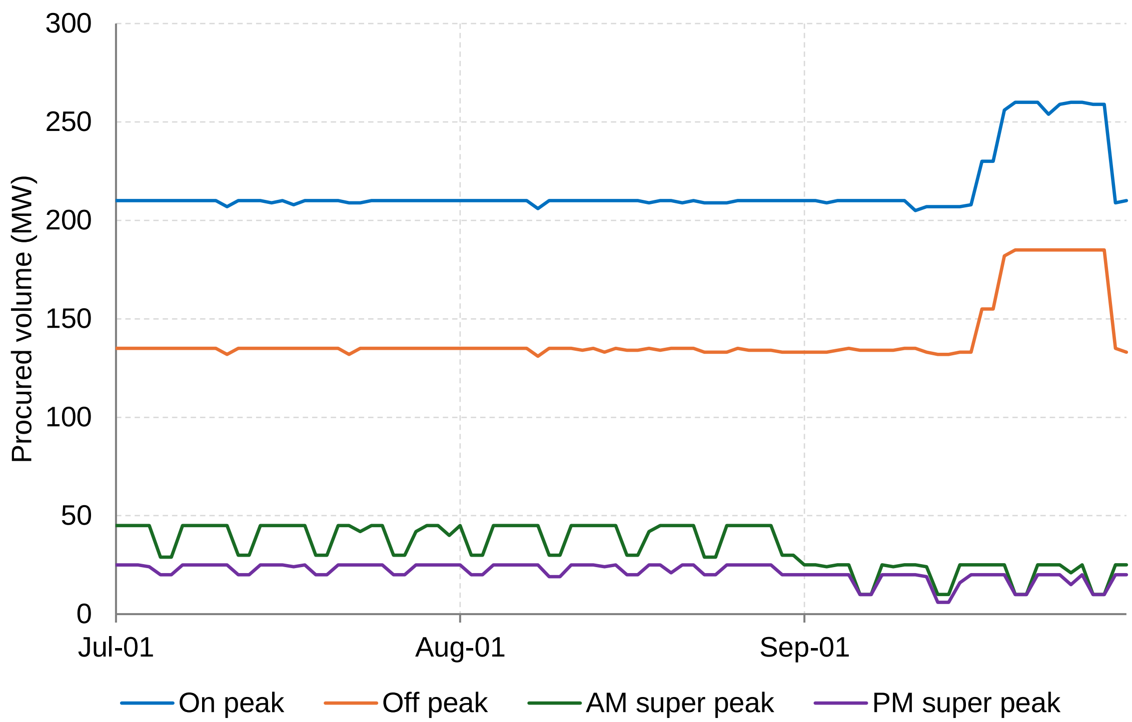
Total OR volumes were relatively consistent year-over-year although regulating reserve volumes increased slightly (Table 26). The higher regulating reserve volumes in Q3 this year were largely the result of the BC/MATL outage. This year, the outage ran from September 19 to 28, affecting 10 days in the quarter whereas last year the outage ran from September 23 to October 3, affecting 8 days in Q3 2024.

Table 26: Total OR volumes, GWh (Q3 and Q3 2024)

	Q3 2024	Q3 2025	Change
Reg	37.5	37.8	1%
Spin	42.5	42.7	0%
Supp	42.6	42.7	0%

In addition, the AESO procured more regulating reserves during the BC/MATL outage this year. For the on-peak period, the AESO procured 260 MW of regulating reserves this year (compared to 250 MW last year), and for the off-peak period the AESO procured 185 MW this year (compared to 175 MW last year). Normal volumes for regulating reserves are 210 MW for the on-peak and 135 MW for the off-peak. Figure 52 illustrates the increase in regulating reserve volumes during the BC/MATL outage.

Figure 52: Regulating reserve volumes (July 1 to September 30)



3.2 Active reserves

Despite higher pool prices and higher demand for regulating reserves during the BC/MATL outage, the average received price of regulating reserves declined by $7.50/MW from Q2 to Q3 (Table 27). This decline was partly driven by the entry of Irrican's Raymond Reservoir asset (26 MW) into the markets for regulating reserves beginning in early August.

Table 27: Average received prices by OR product (Q2 and Q3)

	Q2	Q3	Difference
Pool Price	$40.48	$51.29	$10.81
Reg	$79.87	$72.36	-$7.50
Spin	$20.71	$34.84	$14.12
Supp	$15.35	$27.55	$12.20

Even though Raymond Reservoir provided a relatively small volume of the dispatched regulating reserves (1% in August and 2% in September), the asset had an outsized influence on prices because of the effect of the incremental volumes at the margin.

For example, Table 28 provides the merit order for off-peak regulating reserves for August 6. In this example, the Raymond Reservoir asset (RYMD) offered 8 MW into the market with 7 MW being dispatched. The equilibrium price cleared at $25.00/MW and the AESO procured their full target volume of 135 MW. Without the offers of Raymond Reservoir in this example, the equilibrium price would have been higher at $95.00/MW and the AESO would only have been able to procure 134 MW.

Table 28: The merit order for off-peak regulating reserves (August 6)

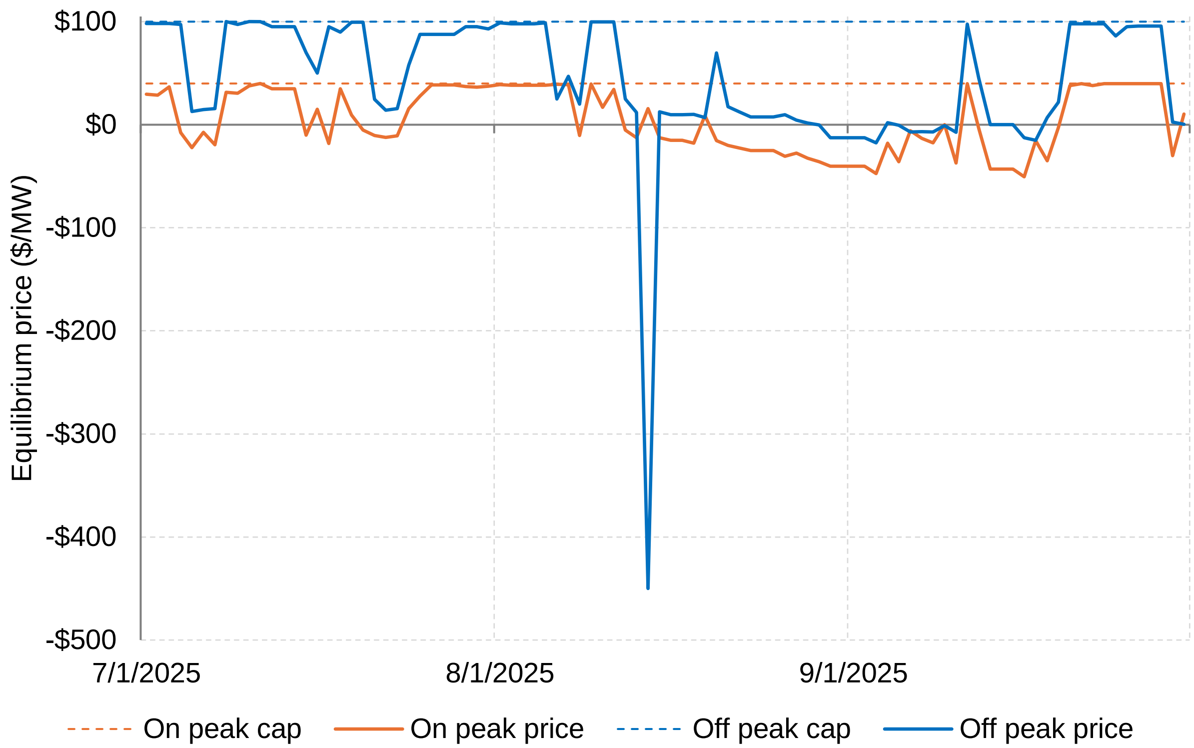
Price	Volume	Cumulative Volume	Asset ID	Company
-$700.00	98	98	BRA	TransAlta
-$550.00	6	104	RYMD	Irrican
-$450.00	20	124	EC01	Enmax
$19.50	1	125	RYMD	Irrican
$25.00	**10**	**135**	**ALS1**	**Air Liquide**
$50.00	1	136	BRA	TransAlta
$73.50	1	137	RYMD	Irrican
$95.00	5	142	BRA	TransAlta

Figure 53 illustrates the equilibrium prices for on-peak and off-peak regulating reserves over Q3. In July pool prices were low and the equilibrium prices for regulating reserves were often close to the caps. In the off-peak market, where the cap is $100/MW, prices cleared at or above $94.99/MW on 52% of days. In the AM super-peak market, where the cap is also $100/MW, prices were at or above $94.99/MW on 74% of days.

In early August the markets for regulating reserves became more competitive following the entry of Raymond Reservoir on August 5.

In the off-peak market for August 14 the equilibrium price for regulating reserves cleared at negative $449.99/MW (Figure 53). This outlier was caused by ENMAX offering additional volumes into the market at lower prices.

Figure 53: Equilibrium prices for on- and off-peak regulating reserves (July 1 to September 30)



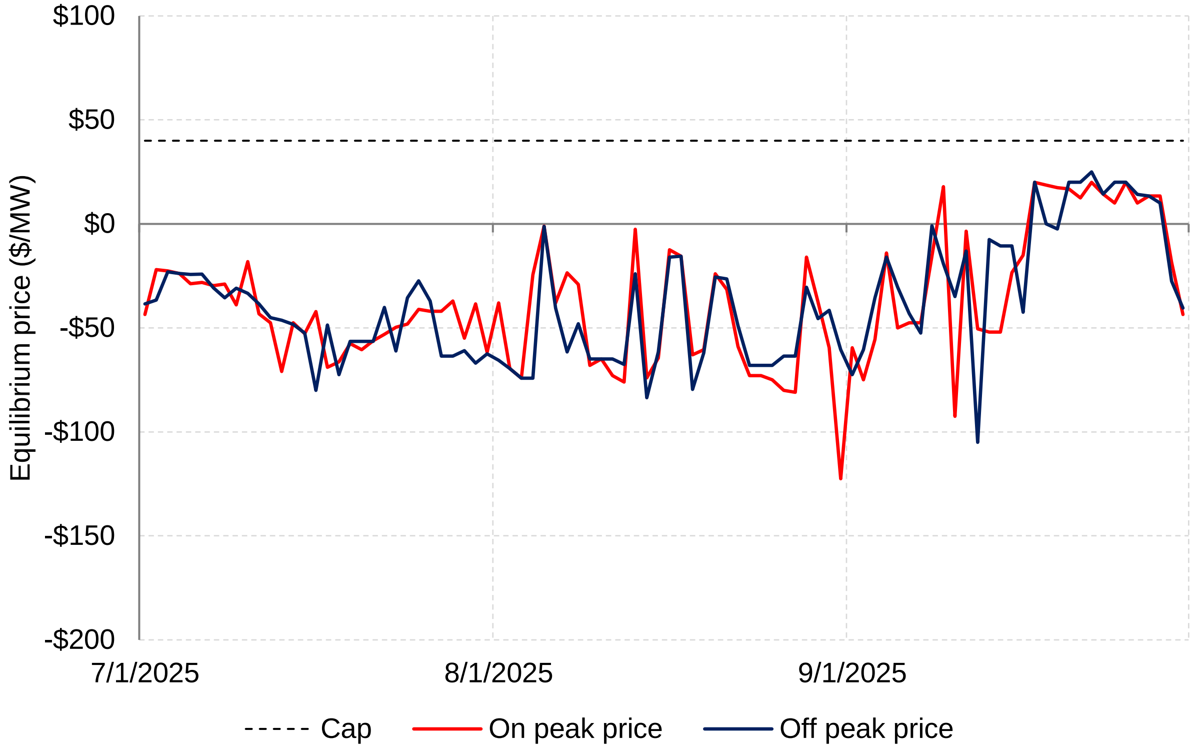
In late September, equilibrium prices for regulating reserves were elevated, and often close to the caps, because of the additional procurement volumes in the on-peak and off-peak markets during the BC/MATL outage (Figure 53). Despite the elevated prices, the AESO were able to procure their higher target volumes of 260 MW for the on-peak and 185 MW for the off-peak for almost all days of the outage.

Figure 54 illustrates the equilibrium prices for spinning reserves over Q3. When pool prices were low in July the equilibrium prices for spinning reserves were often more negative. As a result, providers of spinning reserves did not receive revenues for 84% of the hours in July.

Equilibrium prices for spinning reserves were more volatile in August, following an increase in pool price volatility. For much of September, the AESO procured more FFR due to restrictions on imports. The higher FFR volumes put upward pressure on prices for spinning reserves because some battery assets provided FFR rather than spinning reserves. In late September spinning reserve prices increased further as the AESO procured more regulating reserves during the

BC/MATL outage. As a result, the prices for spinning reserves cleared at a premium to pool prices for much of this period, an unusual outcome because it means capacity held in reserve is priced at a premium to energy.

Figure 54: Equilibrium prices for on- and off-peak spinning reserves (July 1 to September 30)

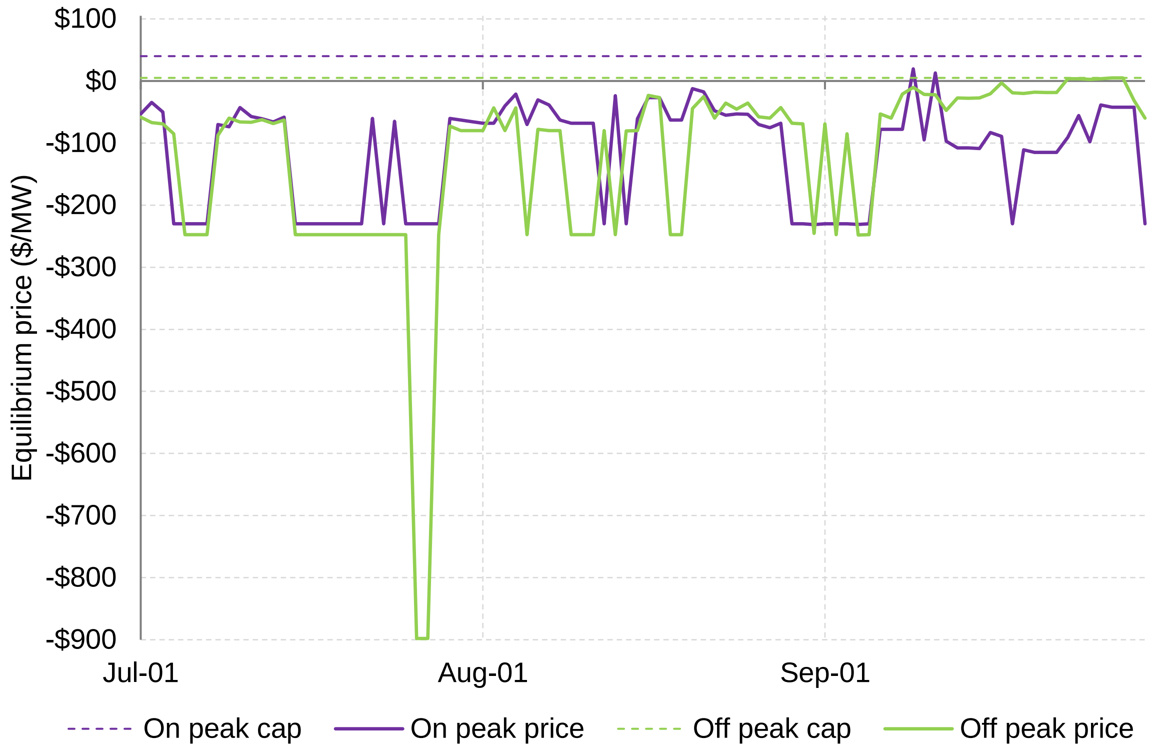


In the supplemental reserves market, in July the low pool prices and low equilibrium prices meant that providers received no revenues for 96% of hours in the month. On July 26 and 27 prices in the off-peak market cleared at negative $898/MW (Figure 55). These outliers were driven by TransAlta offering higher volumes into the market at low prices.

As with the spinning reserves market, prices for supplemental reserves were increased in September as the AESO procured more FFR and battery assets reduced their supply. Prices increased further during the BC/MATL outage as the AESO procured more regulating reserves.

For much of September, the price of off-peak supplemental reserves cleared at a premium to prices during the on-peak, despite higher procurement volumes for the on-peak. These outcomes were largely driven by the increased supply of load assets in the on-peak market.

Figure 55: Equilibrium prices for on- and off-peak supplemental reserves (July 1 to September 30)



3.3 Standby reserves

The AESO procure standby reserves as backup to ensure enough active reserves are available. Standby reserves are activated because of an outage or constraint at an asset providing active reserves or if more active reserves are needed than were expected day-ahead, for example if realized demand is higher than was forecast.

Standby volumes were largely consistent over the quarter with the AESO procuring the normal 20 MW of regulating reserves and 15 MW of supplemental reserves. Beginning on August 1, the volumes of spinning reserves were lowered from 65 MW to 45 MW for the on-peak and from 55 MW to 35 MW for the off-peak, a volume change that is consistent with prior years. The AESO procured additional standby spinning reserves from May 1 to July 31 due to the hydro run-off season in BC.

Table 29 provides activation rates since Q1 2024. In Q3, the activation rates were generally consistent with those observed in Q2 and in Q3 2024. Activation rates for contingency reserves continued to be largely driven by exports in Q3, as exports increase demand and can raise the required volume.

Table 29: Activation rates for OR products (Q1 2024 to Q3 2025)

	Reg	Spin	Supp
Q1 2024	5%	23%	22%
Q2 2024	7%	7%	7%
Q3 2024	5%	12%	13%
Q4 2024	9%	17%	15%
Q1 2025	7%	28%	31%
Q2 2025	7%	11%	19%
Q3 2025	6%	14%	14%

3.4 WattEx issues on September 10

The AESO procure OR on a day-ahead basis through an online trading platform called WattEx, which is operated by ICE NGX. The normal procurement schedule for operating reserves is shown in Table 30.

Table 30: The normal procurement schedule for OR products

Start Time	End Time	OR products
09:00	09:10	Active regulating reserves (on- and off-peak)
09:00	09:20	Active regulating reserves (AM and PM super-peak)
09:00	09:30	Active spinning reserves (on- and off-peak)
09:00	09:40	Active supplemental reserves (on- and off-peak)
09:00	09:50	Standby regulating reserves (on- and off-peak)
09:00	10:00	Standby spinning reserves (on- and off-peak)
09:00	10:10	Standby supplemental reserves (on- and off-peak)

At around 08:50 on the morning of Wednesday, September 10, all users were forced out of the WattEx trading platform. Once the issue was resolved, the trading session was rescheduled to 11:00 and all participants were notified of the new schedule.

Starting at 11:00 market operations progressed as normal and trading was completed for the active markets. However, the system became unavailable again between the close of active supplemental reserves at 11:40 and the close of standby regulating reserves at 11:50. Due to this temporary outage, the standby regulating reserves market closed with no offers.

The standby spinning and supplemental reserves markets were rescheduled to close at 12:50 and 13:00, respectively. However, the market for standby regulating reserves could not be re-opened so the trading for standby regulating reserves was not completed. The AESO determined to conscript any required volumes in real-time.

Some markets may have been less competitive during trading on September 10. For example, in the markets for on-peak and off-peak regulating reserves, the Air Liquide Scotford (ALS1) and Northern Prairie Power Project (NPP1) assets were absent. The price for the on-peak cleared at $39.99/MW compared to negative $37.30/MW the day before and the AESO were only able to procure 205 MW, below the target volume of 210 MW. In the off-peak market, the price cleared at $97.45/MW compared to negative $7.50/MW the day before.

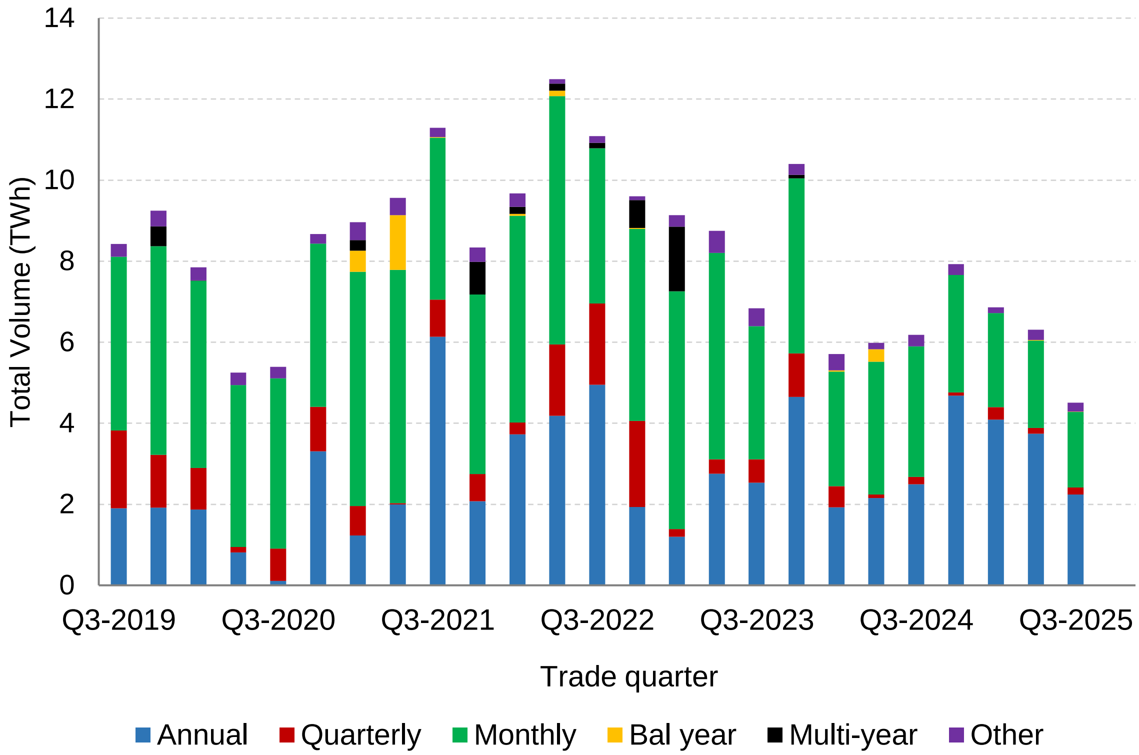
4 THE FORWARD MARKET

Alberta's financial forward market for electricity is an important component of the market because it allows for generators, retailers, and larger loads to hedge against pool price volatility.[10]

4.1 Forward market volumes

Low liquidity in the forward market continued in Q3 with 4.51 TWh traded on ICE NGX or through brokers. This represents a decline of 29% from the previous quarter, and a decline of 27% from Q3 2024. As shown in Figure 56, trade volumes have been relatively low over the past year and a half.

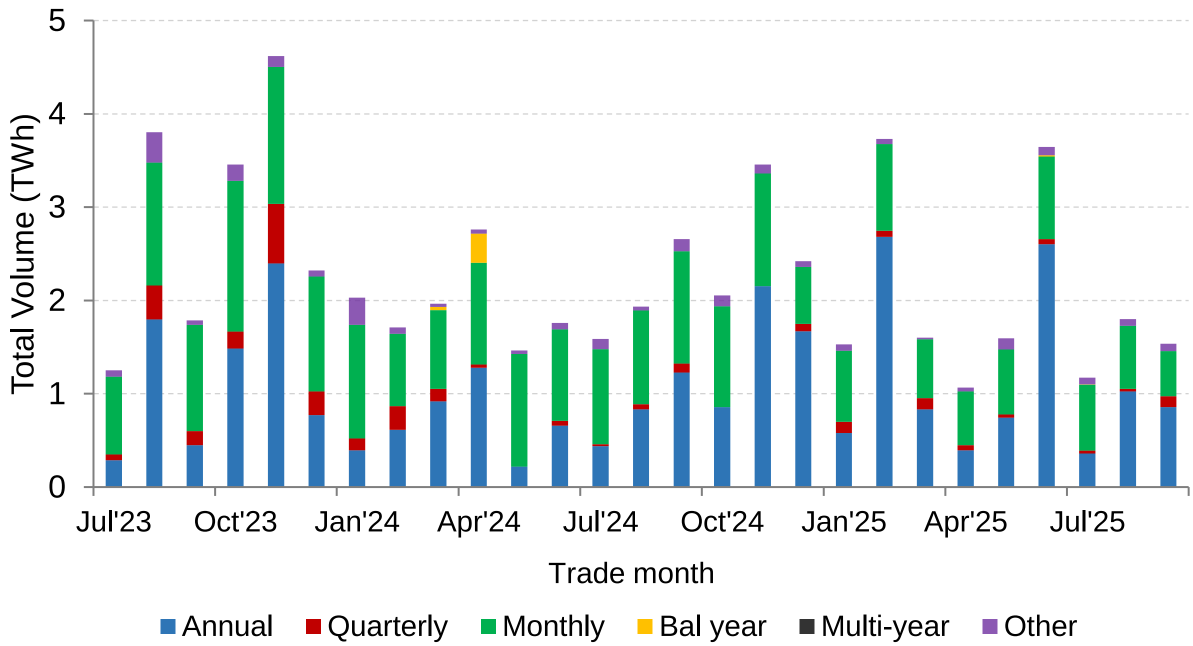
Figure 56: Total trade volumes by term and quarter
(Q3 2019 to Q3 2025, excludes direct bilateral trades)



[10] 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, 2024 are also included unless stated otherwise. 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.

Over the quarter, total volumes were lowest in July and higher in August and September (Figure 57). In July, a total of 1.17 TWh was traded, only slightly above April, which had the lowest monthly volume since May 2007.

Figure 57: Total trade volumes by term and quarter
(July 2023 to September 2025, excludes direct bilateral trades)



4.2 Trading of monthly products

Pool prices came in below forward market expectations in July and August, with pool prices settling lower than the volume-weighted average forward price and the final trade price leading into these months. In September this dynamic reversed, with higher real time pricing compared to forward expectations (Figure 58).

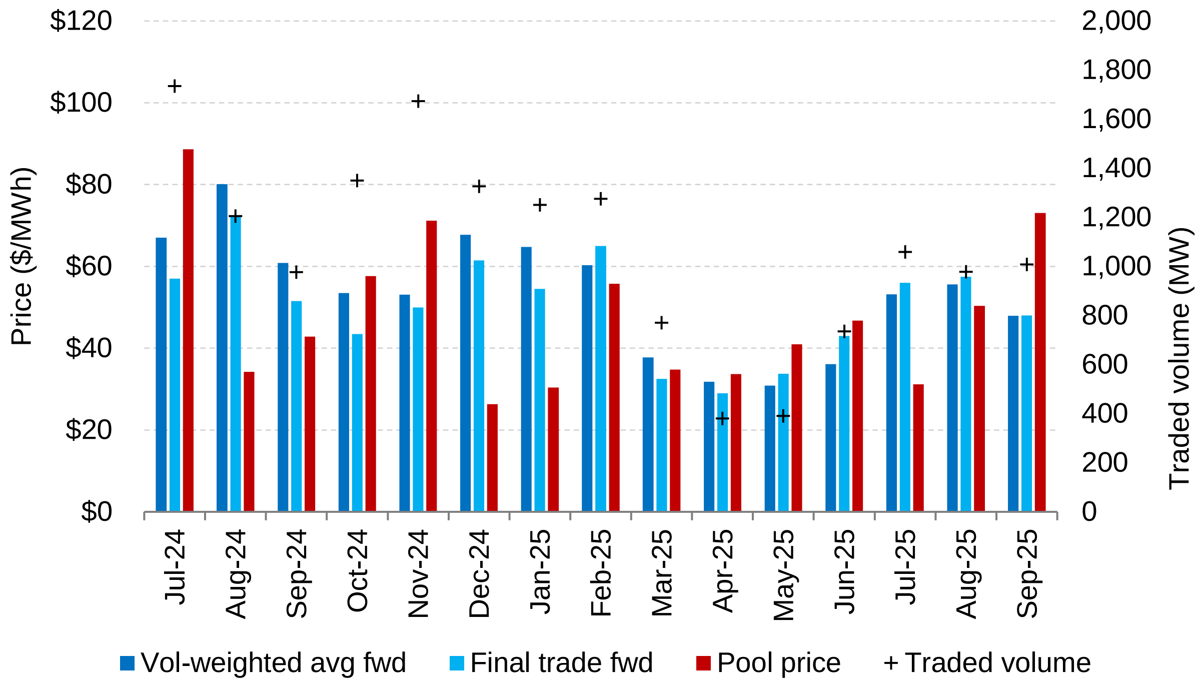
The pool price in July averaged $31.19/MWh, with a volume-weighted average forward price of $53.18/MWh, and a final trade price of $56.00/MWh. The marked price[11] of July generally fell throughout the month as the market was characterised by low pool prices and limited volatility. The marked price fell to a low of $29/MWh as of July 29.

The pool price in August averaged $50.35/MWh, with a volume-weighted average forward price of $55.62/MWh, and a final trade price of $57.50/MWh. The marked price of August fell to $37/MWh as of August 17 but increased due to elevated prices over the next few days and was valued at $51/MWh by August 21.

[11] Marked prices combine realized prices and forward prices for the balance-of-month to calculate the expected average price for a month as of a certain date.

The pool price in September averaged $73.05/MWh, with a volume-weighted average forward price of $47.92/MWh, and a final trade price of $48.00/MWh. The marked price of September had risen to $71/MWh by September 10 due to higher-than-expected pool prices and reached a maximum $77/MWh on September 25.

Figure 58: Monthly flat forward prices and realized average pool prices by month (July 2024 to September 2025)



The evolution of select monthly forward prices over the course of Q3 is shown in Figure 59. The dashed lines in the figure illustrate the marked prices for July, August, and September. In Q3, forward price changes for the prompt month often occurred alongside changes to the prevailing marked price, as forward prices responded to events and outcomes in the energy market.

For example, the low pool prices in July reduced the price of the August contract, and pool price volatility in early September increased the forward price for October. The October contract also increased by 9% on September 26 (from $48.00/MWh to $52.50/MWh) due to buying pressure. In contrast, forward prices for November and December were relatively stable over the quarter closing at $47.25/MWh and $62.00/MWh, respectively on September 30.

Figure 60 shows the distribution of traded volume by monthly contract over Q3. In Q3 the highest traded volume was for the November contract followed by the October contract, which had a large amount of volume traded in the final few days of September.

Figure 59: The evolution of select monthly flat forward prices (June 1 to September 30)

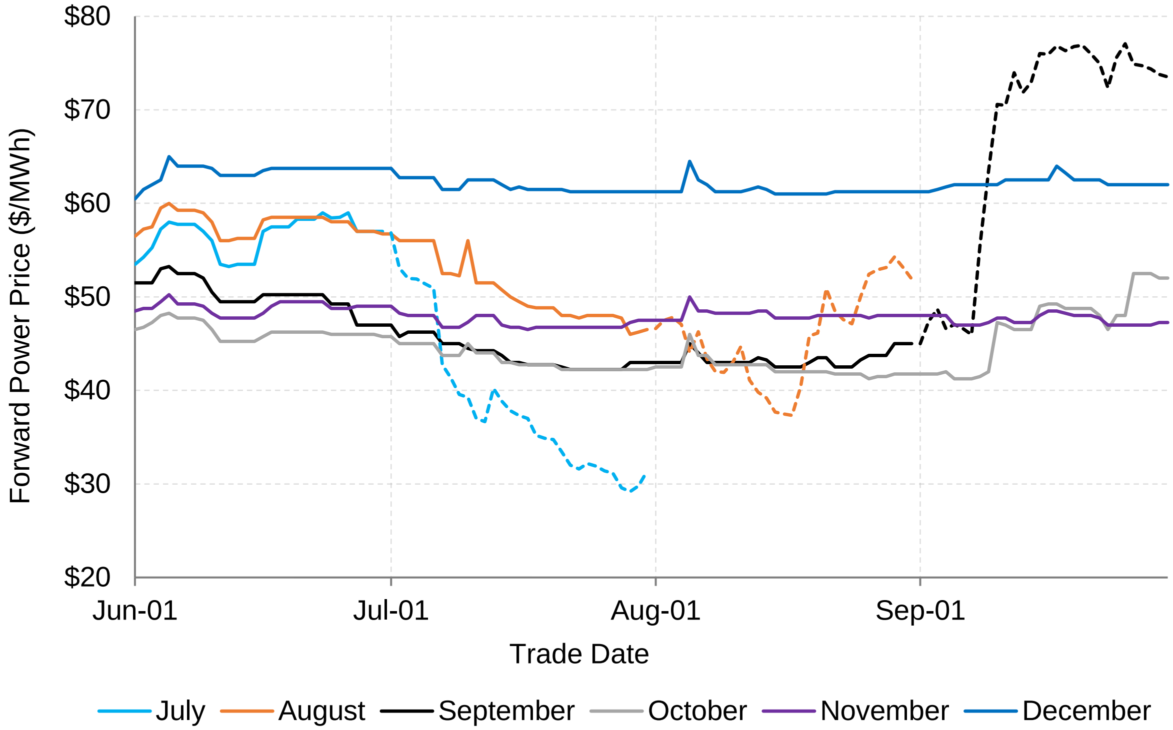


Figure 60: Distribution of volume for monthly trades in Q3[12]

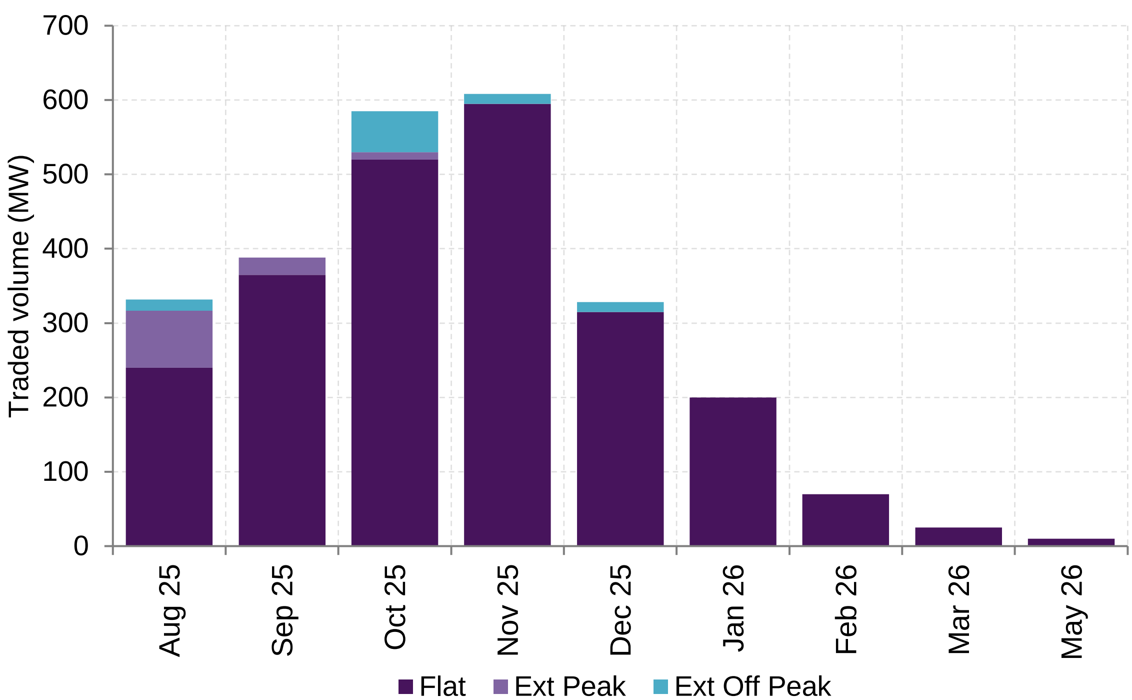
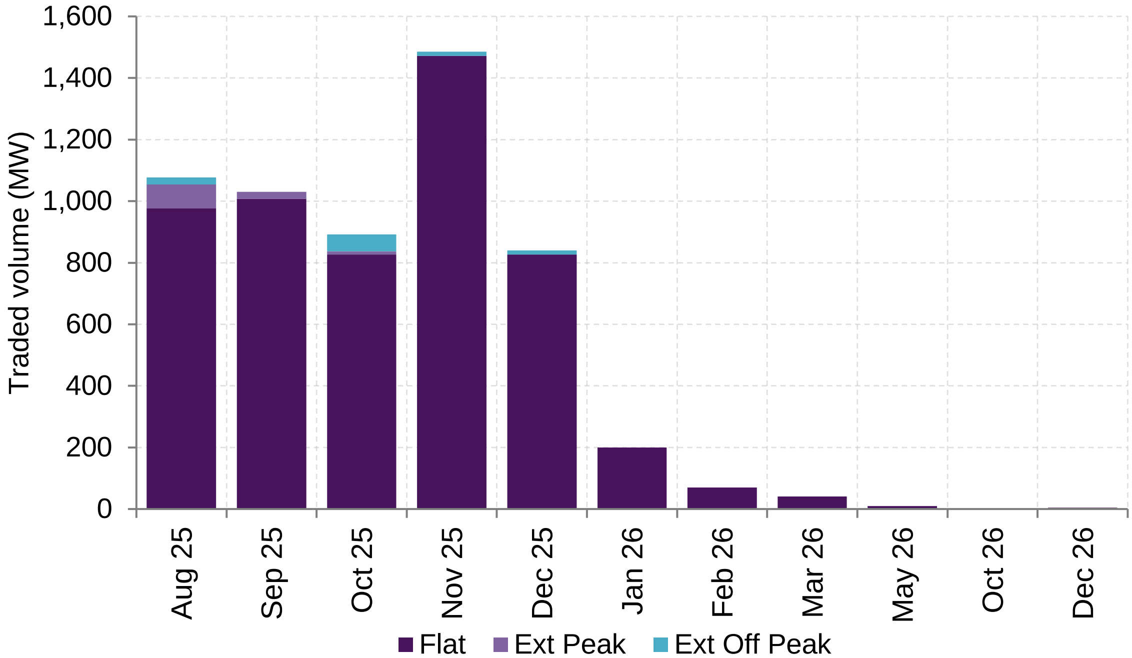


Figure 61 shows the distribution of traded volume by monthly product up to and including Q3. As shown, the volume traded for November outpaces other months by a significant margin. The highest volume of extended peak contracts was traded for August and the highest volume of extended off-peak contracts was traded for October.

Figure 61: Distribution of volume for monthly trades up to and including Q3[13]



4.3 Trading of annual products

Figure 62 shows the evolution of annual forward power prices since July 1, 2024. Annual power price changes were variable over Q3 with Cal 26 decreasing by 6%, Cal 27 remaining flat, Cal 28 increasing by 4%, and Cal 29 increasing by 5% (Table 31).

The marked price for Cal 25 remained relatively flat at $46.44/MWh despite natural gas prices for the balance-of-year falling significantly. As a result, the expected spark spread for Cal 25 increased by 5%. The 6% decline in the price of Cal 26 was in line with falling natural gas prices for that year, which fell by 5% over the quarter. The price increases for Cal 28 and Cal 29 were partly driven by data centre developments.

Annual contracts saw the largest gains on Tuesday, August 5 with prices increasing up to 6% in response to buying pressure and new information on data centre developments. However, annual forward prices slid over subsequent days and remained relatively flat throughout the rest of the quarter (Figure 62).

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[12] Extended peak and extended off-peak products weighted accordingly

[13] Extended peak and extended off-peak products weighted accordingly.

Figure 62: The evolution of annual flat forward prices (July 1, 2024 to September 30, 2025)

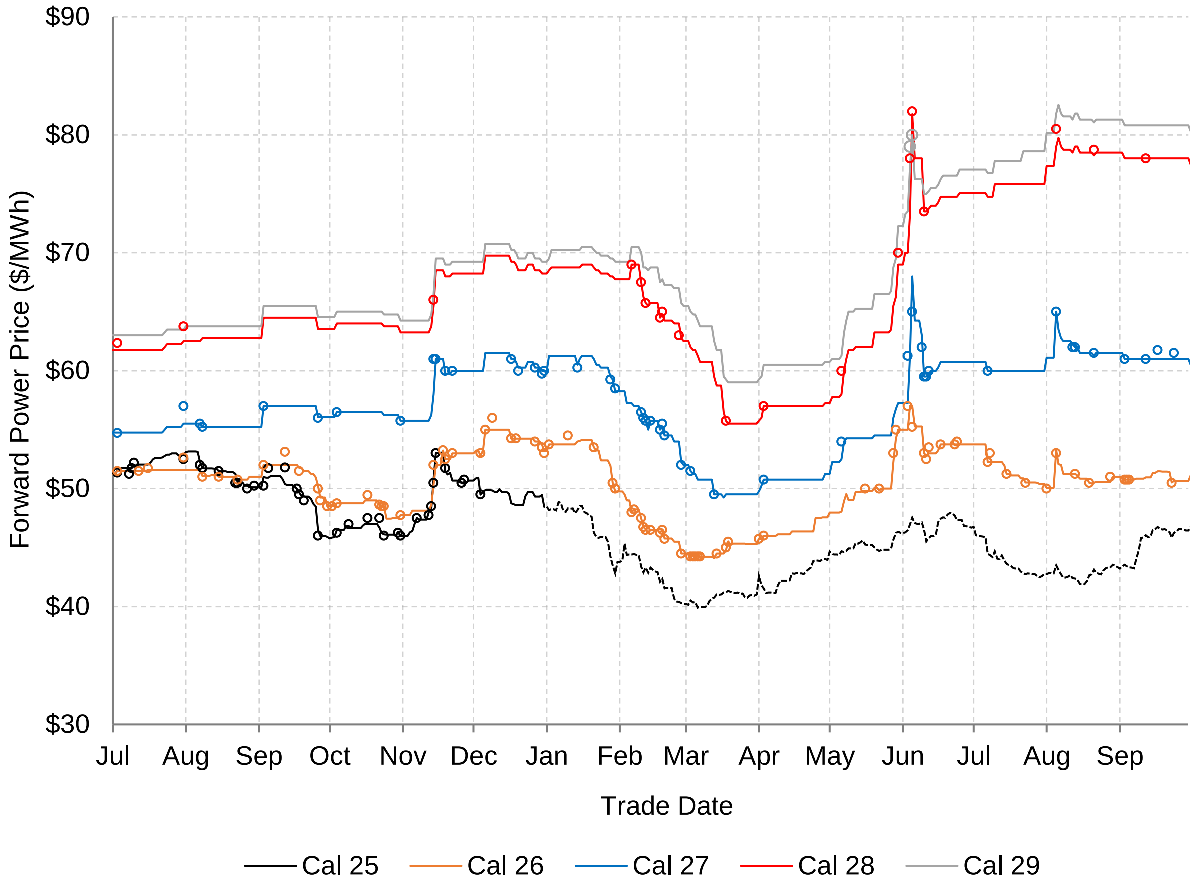

Table 31: Annual power and natural gas price changes over Q3 2025

Contract	Power price ($/MWh)			Gas price ($/GJ)			Spark spread[14] ($/MWh)		
	Jun 30	Sep 30	Chng	Jun 30	Sep 30	Chng	Jun 30	Sep 30	Chng
Cal 25 marked	46.68	46.44	-1%	1.83	1.56	-15%	32.97	34.75	5%
Cal 26	53.75	50.65	-6%	2.98	2.84	-5%	31.41	29.35	-7%
Cal 27	60.75	61.00	0%	2.98	3.07	3%	38.44	37.95	-1%
Cal 28	75.05	78.00	4%	2.94	2.99	1%	52.96	55.59	5%
Cal 29	77.05	80.80	5%	2.96	2.94	-1%	54.81	58.75	7%

[14] Spark spreads assume a heat rate of 7.5 GJ/MWh.

Figure 63 illustrates the cumulative volume traded for annual contracts since January 2022. The total amount traded for Cal 25 was 1,290 MW but Cal 26 has already surpassed this amount with 1,484 MW traded as of September 30. The total volumes traded for Cal 27 and Cal 28 stand at 559 MW and 200 MW, respectively as of September 30.

Figure 63: Cumulative traded volume for the Cal 25 through Cal 29 contracts