Alberta electricity system events on January 13 and April 5, 2024: MSA review and recommendations

August 6, 2024

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EXECUTIVE SUMMARY

This report reviews and makes seven recommendations to the Alberta Electric System Operator (AESO) and market participants related to two electricity system events that occurred in the first half of 2024. While both events involved stressed grid conditions, the driving factors were very different. In addition, the MSA indicates will place high priority on potential contraventions that hinder the AESO's ability to effectively discharge its responsibilities under the *Supply Cushion Regulation* (SCR).

January 13 use of the Alberta Emergency Alert public warning system

The January 13 event occurred during a week-long extreme cold snap that saw temperatures in Alberta plummet below -40°C. The grid was stressed by several temperature-driven factors, including record high demand and equipment failures, leading to generation outages. British Columbia and the U.S. Northwest experienced similar weather conditions, which limited the availability of imports from other jurisdictions.

Leading up to January 13, the AESO's adequacy forecasts predicted tight but manageable conditions. Low wind generation was expected, but other supply sources were forecast by the AESO to be sufficient. However, rising demand and unanticipated generation outages led to Energy Emergency Alert notices from the AESO and imminent load shed. Consequently, the Alberta Emergency Management Agency issued an Alberta Emergency Alert urging Albertans to limit non-essential electricity use (the "Alert").

The Alert was broadcast over TV, radio, websites, social media, the Alberta Emergency Alert mobile app, and compatible smart phones. The MSA estimates the Alert reduced demand by approximately 350 MW over an hour. As a result, no firm load was shed during this event.

Load shed event on April 5

The April 5 event was different in that high demand was not a contributing factor. On April 3, a supply surplus event was quickly followed by an Energy Emergency Alert after the coincident loss of approximately 3,000 MW of wind and solar generation. This event demonstrates how supply adequacy can shift rapidly and unexpectedly.

Through the morning of April 5, a series of outages in short succession compounded with existing outages to reduce the supply of thermal generation by approximately 4,000 MW. Combined with approximately 400 MW less wind generation than anticipated, this led to emergency conditions resulting in 244 MW of firm load shed. This was the first firm load shed in the province since 2013.

The report, including the recommendations, makes extensive use of data available to the MSA that are not publicly available, including: regional demand, demand from price responsive loads, AESO emergency directives, including distribution voltage reductions and load shed preparations, outage and derate declarations at the asset level, output underlying the Supply Adequacy Report and Market Supply Cushion Report, contingency reserve directives, and emergency interchange measures, including emergency imports and Northwest Power Pool Reserve Sharing imports.

RECOMMENDATIONS

The MSA makes the following seven recommendations based on the observations set out in this report, as well as its broader understanding of current and potential future issues in Alberta's electricity market.

1. **The AESO should ensure that an efficient and effective unit commitment process is developed as part of the Restructured Energy Market (REM) / Day-Ahead Market (DAM):** the tolerance of supply shortfall risk is inherently higher for generation owners than for the public. On April 5, Battle River 5 was commercially offline when load was shed. Under the provisions of the SCR, the asset would have been committed by the AESO, and if the asset had been able to respond, no load would have been shed.

2. **The AESO should review the calculation of market supply cushion and retain all published data:** the AESO has implemented amendments to its Market Supply Cushion Report that may improve its ability to forecast tight supply conditions. The AESO should seek out opportunities for other improvements to the underlying forecast data, such as net imports and constrained down generation. This is especially important as the report forms the basis for unit commitment decisions under the SCR. Further, the AESO should retain all data it publishes, including for the Market Supply Cushion Report, to facilitate monitoring of unit commitment decisions, identify opportunities to improve the forecast, and ensure compliance with the SCR.

3. **The AESO should publish methodology used to determine import capability under emergency conditions:** the AESO should make public the methodology used to determine BC/MATL import capability while operating under emergency conditions, or conditions not represented in *ISO rule 203.6, Available Transfer Capability and Transfer Path Management* and related documentation.

4. **The AESO should publish system event reports:** there will be learnings from events related to grid operations that the AESO is positioned to uncover and share with industry. The AESO has prepared public event reports in the past and should do so following system events.

With the enactment of the SCR, the accuracy of certain data market participants submit to the AESO are of increased importance due to how they impact the AESO's ability to discharge its responsibilities under the SCR. **The AESO should devote sufficient compliance monitoring resources to identify instances of suspected contraventions and refer these, if any, to the MSA. The MSA will place high priority on potential contraventions that hinder the AESO's ability to effectively discharge its responsibilities under the SCR**.

5. **Market participants should improve available capability declarations submitted to the AESO:** some generation assets routinely submit default availability declarations until close to real time. These default submissions declare that the asset can provide its full capacity, or close to full capacity, when often temperatures or site conditions mean this is

not possible. Having these participants accurately reflect the capability of their assets sooner would help the AESO properly forecast the supply demand balance.

6. **Market participants should improve the input of physical parameters that may be relevant to unit commitment decisions made by the AESO:** market participants must ensure that the physical parameters entered for their assets are accurate and up to date, including initial start-up times that are dependent on the status of the unit (e.g., how warm it is).

7. **Market participants should improve the quality of outage reasons submitted to the AESO:** outage reasons declared by market participants are not always adequately descriptive. More descriptive outage reasons should be provided by market participants and outage reasons should be routinely audited by the AESO, including physical audits as appropriate.

1 JANUARY 2024 ALBERTA EMERGENCY ALERT EVENT

1.1 Event summary

- On January 13 at 18:44 (which is in hour ending (HE) 19), the Alberta Emergency Management Agency issued an Alberta Emergency Alert stating that "extreme cold resulting in high power demand has placed the Alberta grid at a high risk of rotating power outages." Albertans were asked to immediately limit their electricity use to essential needs only.

- The January 13 event occurred during a period of extreme low temperatures which increased demand, including record peak demand of 12,384 MW on January 11 during HE 18. The extreme low temperatures are estimated by the MSA to have increased peak demand by approximately 10% compared to average January temperatures. Without these extreme temperatures, the alert would not have been necessary.

- The Alert on January 13 is estimated by the MSA to have reduced demand by approximately 350 MW. Before the Alert, price responsive loads had already voluntarily curtailed approximately 200 MW.

- Existing outages at Sundance 6 and Cloverbar 3 and forced outages at Cascade 1, HR Milner, Genesee 1, Syncrude #1, and Cavalier reduced available supply on January 13.

- Wind generation was very low throughout the day. The wind forecast started to anticipate this around January 11.

- The AESO's Supply Adequacy Report was slow to signal reduced supply, while the Market Supply Cushion Report outlook started worsening approximately 24 hours before the alert.

- 100% of spinning reserves were directed to provide energy for 17 minutes and 100% of supplemental reserves were directed to provide energy for 66 minutes. These periods coincided for six minutes, during which time all contingency reserves had been directed to provide energy.

- Natural gas prices were elevated leading up to January 13, but were lower on January 13 due to factors such as reduced natural gas export capacity. The supply of natural gas to thermal generation assets was not a cause of the supply shortfall on January 13.

- Market-based imports were limited on January 13 due to high prices and reliability concerns in other jurisdictions. However, Alberta called upon emergency imports and Northwest Power Pool Reserve Sharing imports during the evening peak in demand.

1.2 Demand

A period of exceptionally cold weather drove high demand in mid-January, with a new record set in HE 18 of January 11. Following this, the AESO declared EEA events on four consecutive days, from January 12 through 15. Without the exceptionally cold weather, demand would have been lower, likely preventing the EEA events and avoiding the need to issue the Alert on January 13. The Alert effectively reduced electricity demand by around 350 MW and likely prevented firm load shed.

1.2.1 Actual and forecast demand

In mid-January, a cold weather system moved into Alberta, which increased electricity demand due to higher heating load. As shown by Figure 1, temperatures were exceptionally low from January 11 to 14. On January 11, Alberta set a new demand record of 12,384 MW in HE 18. However, from January 12 to 15 higher pool prices moderated demand (Figure 2).

Figure 1: Hourly temperatures in Calgary, Edmonton, and Fort McMurray (January 8 to 21)

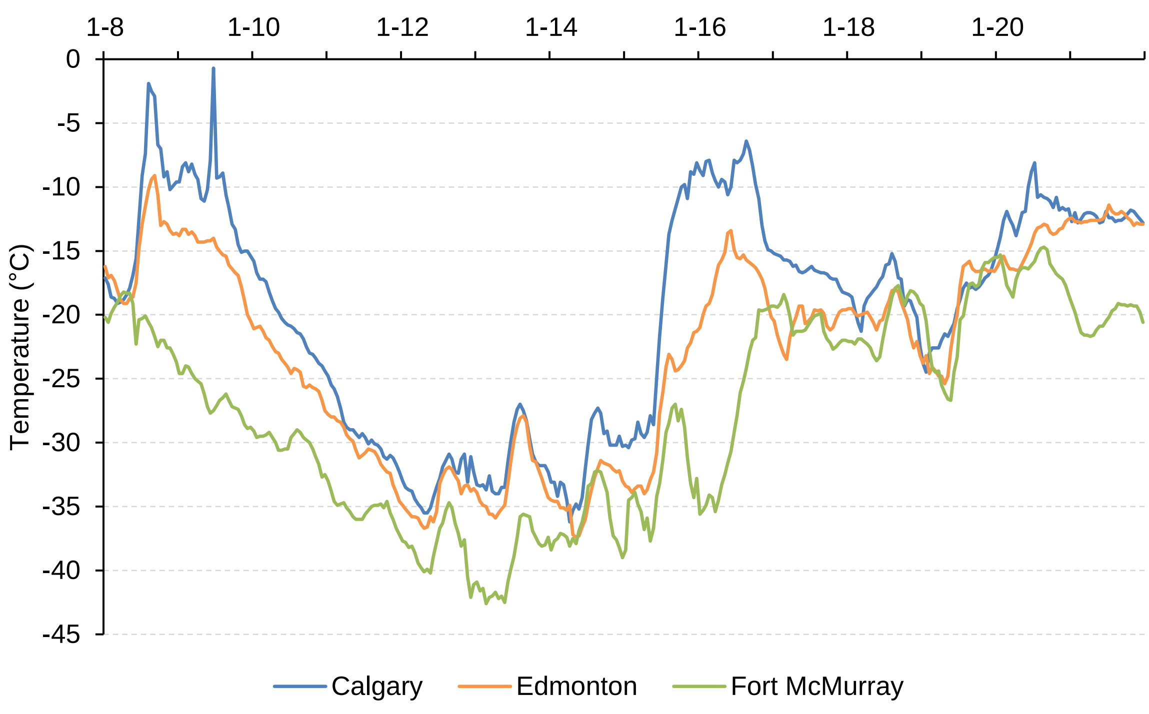
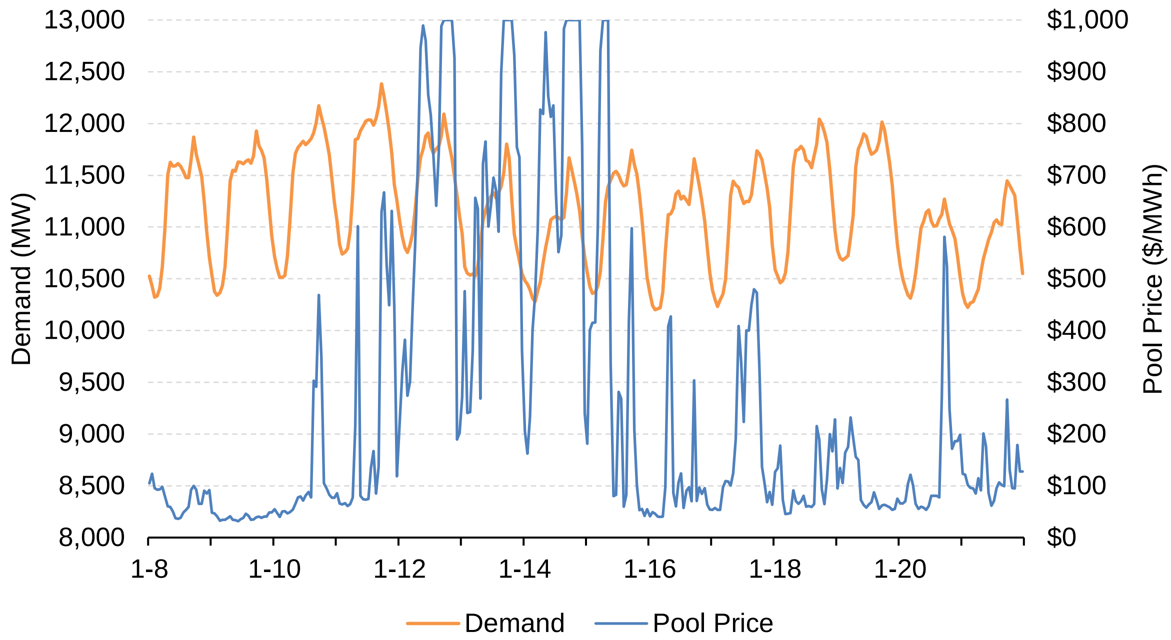


Figure 2: Hourly demand and pool price (January 8 to 21)



The new demand record set on January 11 exceeded the previous record by 191 MW or 1.6% (Table 1). The pool price was lower at $629/MWh during the new demand record hour, whereas the pool price was $999.99/MWh during the prior demand record hour and the AESO had declared an EEA 3 event. Wind generation was relatively high during the new demand record hour, which lowered prices (Table 1).

Table 1: Market statistics during the new load record compared to the prior load record

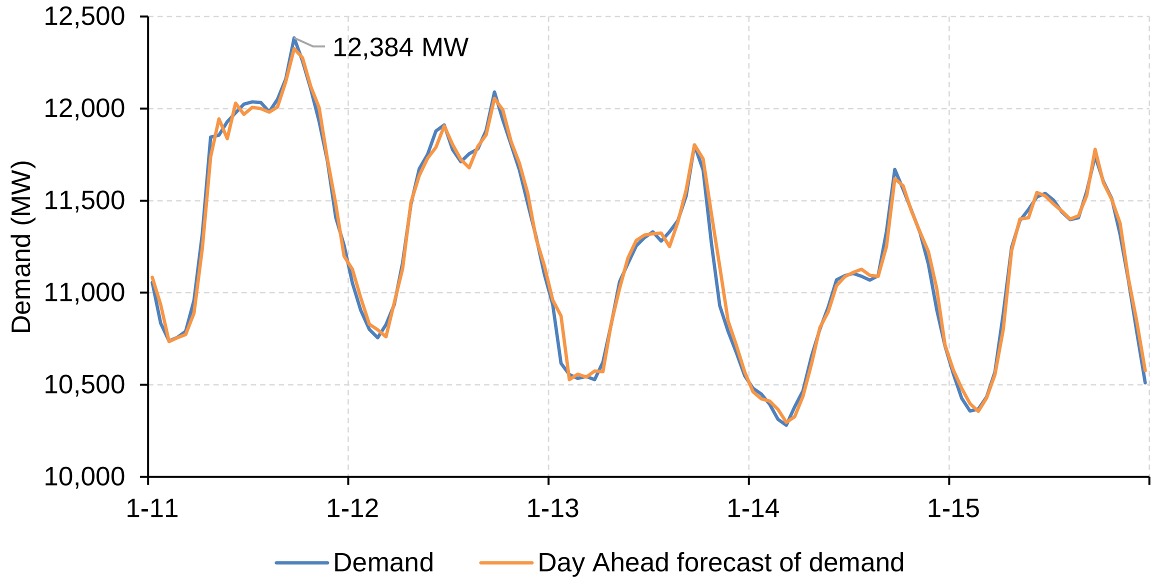
	New load record	**Prior load record**
Date	Jan 11, 2024	Dec 21, 2022
Weekday	Thursday	Wednesday
Hour Ending	18	18
Demand (MW)	12,384	12,193
Pool Price ($/MWh)	$629.01	$999.99
Temperature (°C)	-32.3	-29.5
Supply Cushion (MW)	322	0
Wind generation (MW)	1,111	603
Solar generation (MW)	0	0

Due to the cold temperatures and elevated demand, in addition to low wind generation and some thermal generator outages, the AESO declared EEA events on each day from January 12 to 15.

The AESO's day-ahead forecast of demand performed well during the January cold snap events (Figure 3). From January 11 to 15 the average absolute forecast error was low at 39 MW or 0.3% of the average load.

The AESO correctly predicted that a new record demand would be set in HE 18 of January 11, although their forecast of 12,326 MW was slightly (58 MW) below actual demand in the hour.

Figure 3: Demand and forecast demand (January 10 to 16)



For peak demand on January 13, the AESO's day-ahead forecast predicted actual demand with a forecast error of only 1 MW (Table 2). After the Alert was issued on January 13, actual demand came in under the day-ahead forecast as one might expect. For example, in HE 20 of January 13, actual demand came in 160 MW below the day-ahead forecast as a result of the Alert, and in HE 21 actual demand came in 212 MW below the forecast (Table 2).

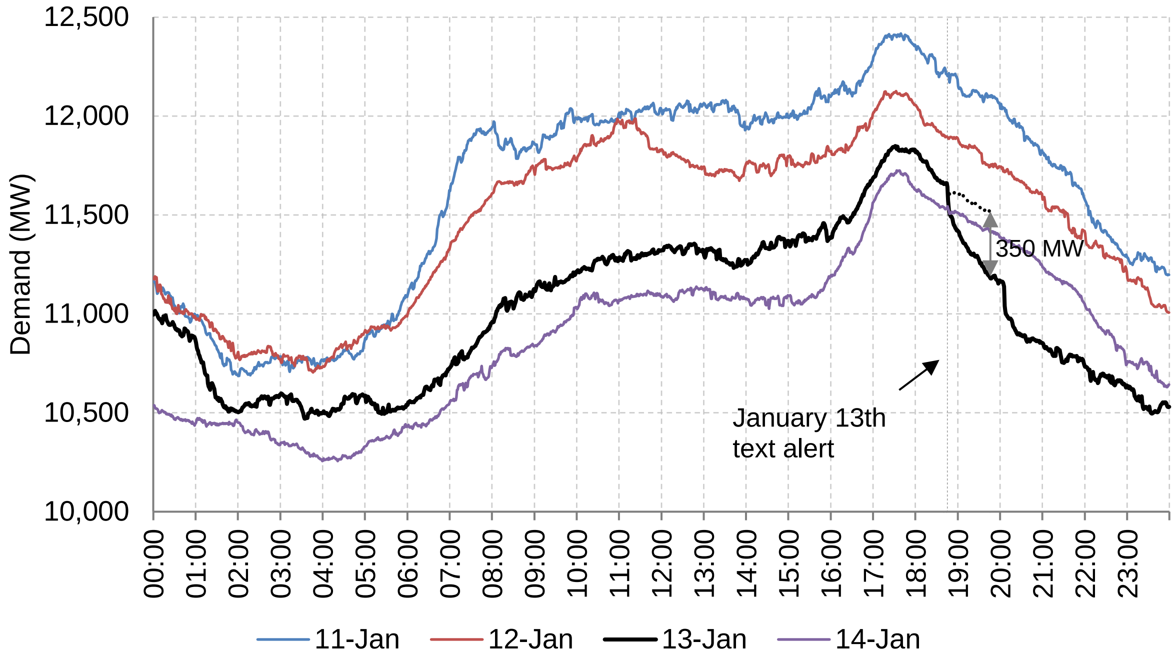
Table 2: Pool price, demand, and forecast demand for select hours (January 13)

Date	Hour Ending	Pool Price ($/MWh)	Demand (MW)	Day-ahead forecast of demand (MW)	Forecast error (MW)
1/13/2024	15	$590.92	11,331	11,251	-80
1/13/2024	16	$898.00	11,391	11,383	-8
1/13/2024	17	$999.99	11,525	11,558	33
1/13/2024	18	$999.99	11,802	11,803	1
1/13/2024	19	$999.99	11,666	11,728	62
1/13/2024	20	$999.99	11,268	11,428	160
1/13/2024	21	$931.28	10,930	11,142	212
1/13/2024	22	$754.14	10,791	10,847	56

1.2.2 Response to the Alberta Emergency Alert

Figure 4 illustrates the daily demand profile for January 11 to 14 to show the drop in demand following the Alert on January 13. At 18:40, five minutes prior to the Alert, demand on January 13 was 118 MW higher than demand on January 14. Demand at 19:45 on January 13 was 233 MW lower than demand at the same time on January 14. Using January 14 as a baseline (the dotted black line in the figure), this implies a demand decline in response to the Alert of around 350 MW or 3% of total demand.

Figure 4: Daily demand profile (January 11 to 14)



Before the Alert, the AESO requested a 3% voltage reduction from some distribution facility owners and requested load shed preparations across the province.[1] Based on the supply adequacy conditions at the time, there would likely have been firm load shed absent the Alert.

Figure 5 illustrates the response to the text alert by planning region. As shown, the decline in demand was largest in Edmonton and Calgary. In Edmonton demand fell by 162 MW between 18:40 and 19:45 while in Calgary demand fell by 135 MW.

Table 3 provides a breakdown of the demand response to the Alert by AESO planning region. Demand in Calgary fell by 8% between 18:40 and 19:45 while demand in Edmonton fell by 7%. To provide a baseline for the expected demand drop, Table 3 also provides the demand decline

[1] AESO system controller calls 9327, 9329 to 9333, 9338, 9340, and 9343 on January 13, 2024, from 15:33:09 to 15:49:09.

over the same time period on January 14. All planning regions saw a larger demand decline between 18:40 and 19:45 on January 13 than January 14.

Figure 5: Daily demand profile by planning region (January 13)

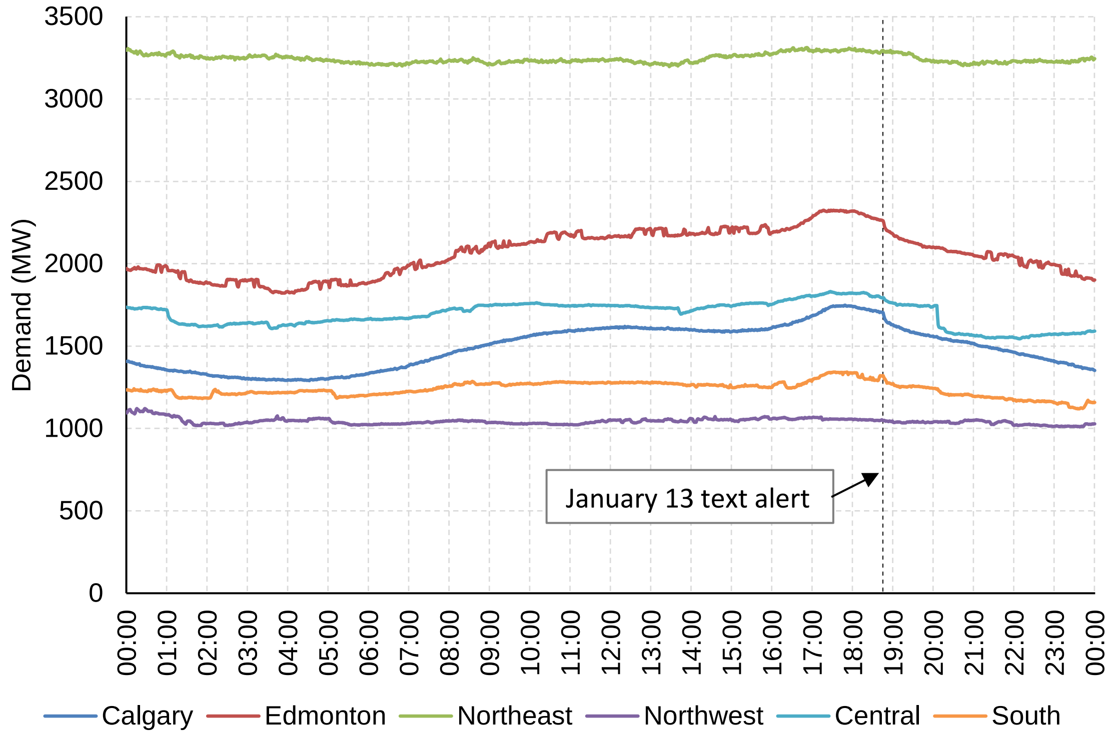


Table 3: Demand change by planning region (January 13)

	January 13				January 14	Difference	
	Load at 18:40	**Load at 19:45**	**Change (MW)**	**Change (%)**	**Change (MW)**	**Change (%)**	**Change (MW)**
Calgary	1,704	1,569	-135	-8%	-55	-3%	-80
Central	1,798	1,745	-53	-3%	-2	0%	-51
Edmonton	2,265	2,103	-162	-7%	-43	-2%	-119
Northeast	3,277	3,231	-46	-1%	8	0%	-54
Northwest	1,048	1,041	-7	-1%	-4	0%	-3
South	1,315	1,250	-65	-5%	-23	-2%	-42
Total	**11,407**	**10,939**	**-469**	**-4%**	**-119**	**-1%**	**-350**

While the Alert was effective, the MSA notes that routine use of the Alberta Emergency Alert program during EEA events may result in diminished consumer response over time. Evidence from the Flex Alert program in California suggests that voluntary demand response alerts can be effective but are unreliable and tend to perform worse in extreme weather events when the grid is most strained.[2]

1.2.3 Effect of the extreme cold on demand in January

Given the extreme cold and high demand Alberta experienced during the January cold snap, including a new demand record on January 11, the MSA has constructed a counterfactual scenario to illustrate what demand would have been under average January temperatures. The record demand highlights the additional strain placed on the grid due to the unusually cold weather.

The link between temperature and electricity demand is complex, nonlinear, and influenced by multiple factors, including daily and seasonal patterns. To effectively model this relationship, hourly data from 2013 to 2023 were used to estimate a regression model with carefully chosen features.[3]

With the estimated model, counterfactual demand was estimated using the average January temperatures for each hour over the past ten years (2013 to 2023). Using decadal hourly averages establishes a stable baseline, smoothing out year-to-year climatic irregularities, and reflecting typical January weather patterns. This baseline is crucial for accurately measuring the deviations caused by the extreme cold, providing a reliable benchmark for understanding the impact of such weather events on electricity demand.

Figure 6 and the summary statistics in Table 4 illustrate that on January 11, observed temperatures were lower than the decadal average January temperatures from 2013 to 2023 for the entire 24-hour period. While average January temperatures ranged from -6.6°C to -10.9°C, the observed temperatures fell between -28.5°C and -34.7°C. This substantial deviation highlights

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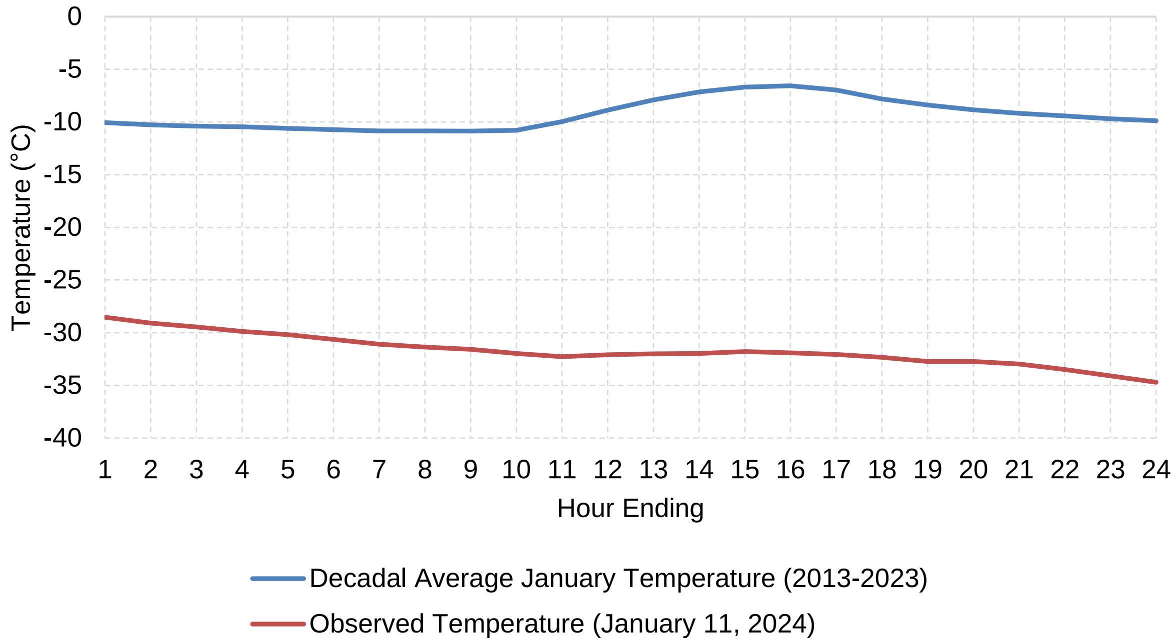
[2] *Residential electricity demand on CAISO Flex Alert days: a case study of voluntary emergency demand response programs.* Peplinski and Sanders, 2023. https://iopscience.iop.org/article/10.1088/2753-3751/ad0fda/pdf

[3] Initially, a feature selection technique determined the optimal polynomial degree for temperature to capture the nonlinear dynamics accurately. Using raw temperature with polynomial terms allows for more detailed and nuanced modeling than Heating Degree Days (HDDs) and Cooling Degree Days (CDDs) because it captures the continuous relationship between temperature and electricity load, more precisely accommodating non-linear effects and variations. A standard regression approach was then applied, integrating time-fixed effects to account for cyclic and seasonal variations, thereby isolating the temperature's influence from other factors. Including time-fixed effects enhances the model's ability to identify regular patterns and control temperature-unrelated anomalies.

Post-estimation evaluation indicated that standard assumptions were violated, and the model was sensitive to outliers. To address this, robust regression was utilized to mitigate the impact of outliers and other violated assumptions, ensuring more reliable parameter estimates. Bootstrapping was employed to protect the model from being overly sensitive to specific data points, ensuring robustness and generalizability. Bootstrapping involves resampling data with replacement to estimate the distribution of an estimator and to construct confidence intervals. This technique reduces variance in estimates, crucial for predicting rare or extreme events. It also ensures robustness in model validation, verifying that findings are consistent across various samples. In this study, 999 bootstrap iterations were performed to enhance the stability and reliability of the model's predictions.

the severity of the January cold snap, indicating a much colder day than usual, which resulted in increased electricity demand due to heightened heating needs.

Figure 6: Observed vs. decadal January average temperature



Despite the extreme difference in mean temperatures, the standard deviations are similar (Table 4), indicating that temperature variability is comparable across both time periods. This similarity means that, while the temperatures on January 11 were much lower than the decadal January average, the range of temperature fluctuations was typical for that month. This consistency in variability supports the use of decadal averages for constructing the counterfactual estimation.

Table 4: Summary statistics (°C)

	Decadal average January temperature	**Observed temperature**
Mean	-9.3	-31.7
Maximum	-6.6	-28.5
Minimum	-10.9	-34.7
Std. dev.	1.4	1.5

Figure 7 indicates that the actual demand (blue line) on January 11 was higher than the counterfactual demand based on average January temperatures (shown by the dashed line[4]) throughout the day. Based on typical January weather conditions, the predicted values show a

[4] The light pink shaded area surrounding the counterfactual estimation signifies the 95% confidence interval derived from bootstrapping.

lower and smoother demand profile. However, the similar shape patterns between the actual and predicted lines reflects the model's capability to capture the overall trend effectively.

The increase in actual demand during the late afternoon and evening of January 11 underscores the effect of the severe cold on electricity demand. The evening increase in demand is much lower in the counterfactual demand, and this discrepancy emphasizes the additional strain on the grid caused by the extreme weather event.

Figure 7: Actual vs. counterfactual AIL demand on January 11, 2024

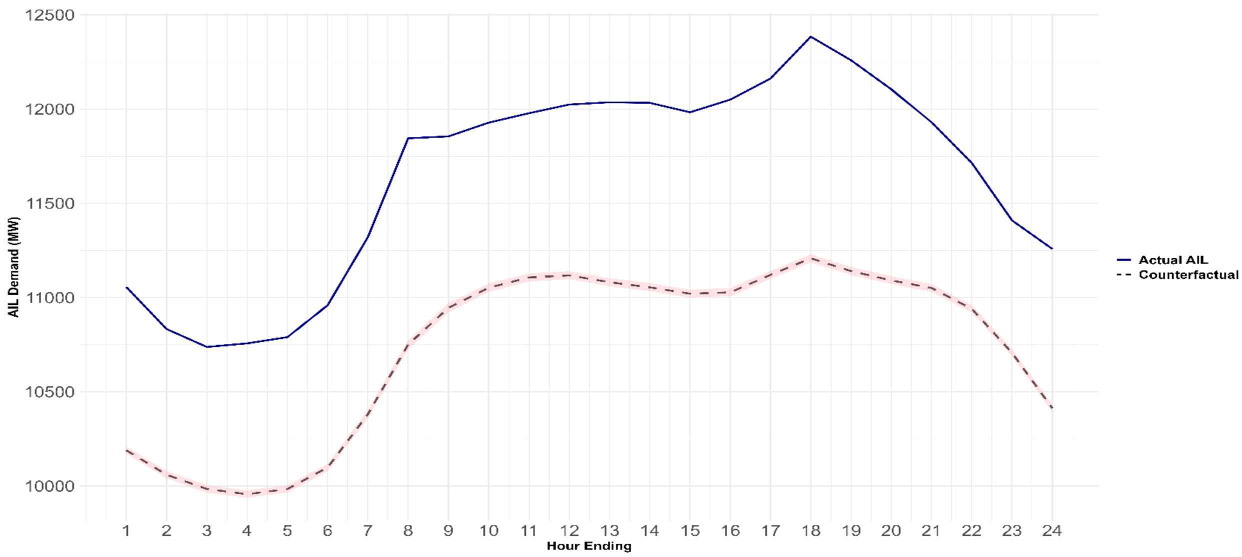
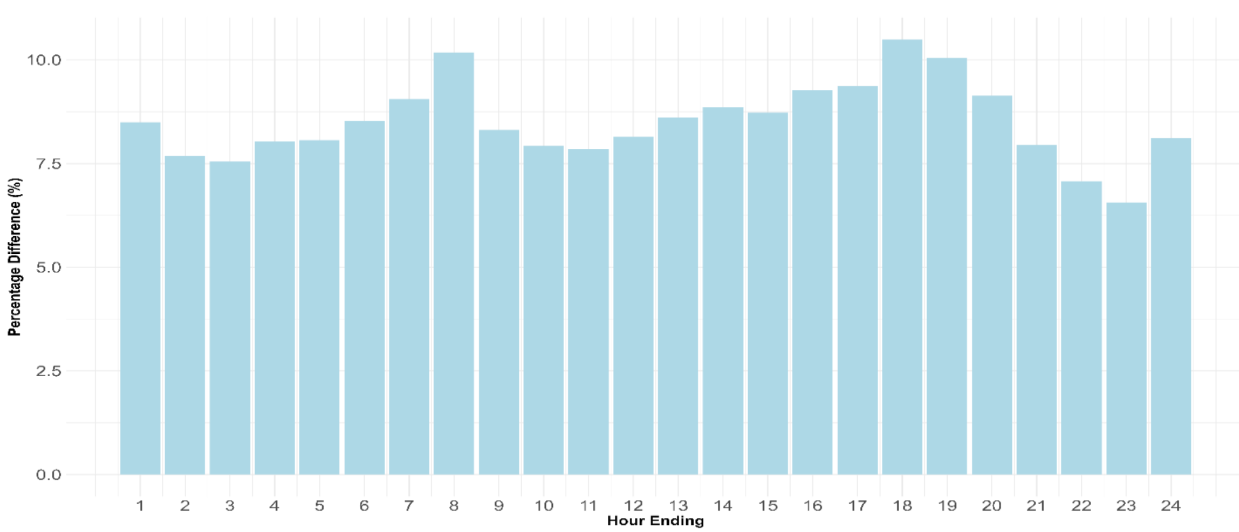


Figure 8 illustrates the hourly percentage difference between the actual demand and the counterfactual demand on January 11, complementing the findings shown in Figure 7. The percentage difference consistently ranges from around 7% to over 10% throughout the day, with the largest discrepancies occurring in the morning ramp and early evening, peaking in HE 18.

Figure 8: Hourly percentage difference in AIL demand (actual vs. counterfactual)

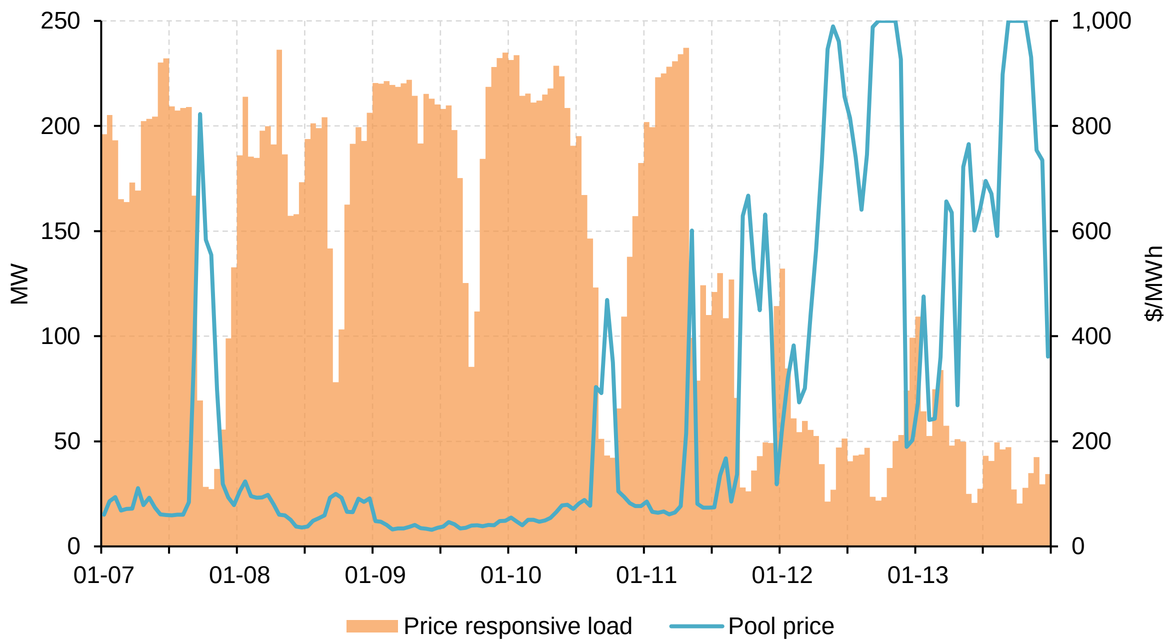


1.2.4 Price responsive load

Some electricity consumers (loads) in Alberta are responsive to pool prices. While they do not directly participate in the energy market by explicitly bidding for energy, they actively adjust their consumption based on forecasted and observed prices.

As shown in Figure 9, during the week leading up to the Alert, the highest observed aggregate consumption by price responsive loads[5] was approximately 240 MW. As is typical for these loads, they reduced their consumption during peak hours, presumably to avoid both higher pool prices and potential ISO tariff charges.

Figure 9: Price responsive load on January 7 to 13, 2024



Beginning at midday on January 11, the supply cushion was consistently low with correspondingly high pool prices. As a result, price responsive loads voluntarily curtailed by approximately 120 MW and shortly thereafter by another 50 MW. By the time of the Alert on January 13, price responsive loads had already curtailed approximately 200 MW of consumption in response to high prices. These loads did not further curtail their consumption in response to the Alert.

1.3 Outages

Thermal generator outages at Sundance 6, Cloverbar 3, HR Milner, Cascade 1, Syncrude #1, Genesee 1, and Cavalier, reduced supply during the EEA event on January 13. In addition, there were outages at two of the larger hydro assets in the province.

[5] As identified by the AESO.

In addition to high demand, supply adequacy surrounding the Alert was affected by generator outages. Some outages were scheduled in advance, while others were unexpected. There were no assets commercially offline during the Alert.

Prior to January 6, outages at Sundance 6 (401 MW) and Cloverbar 3 (101 MW) had been submitted for January 13. On December 17, 2023, Sundance 6 had an operational issue that derated the unit to around 250 MW. As of December 22, an outage was scheduled to run from January 6 to 14 to fix the issue, though the actual outage ran from January 6 to 15.

The outage at Cloverbar 3 was also scheduled well before January 13. Cloverbar 3 went offline on November 17, 2023, and as of November 21, 2023, the asset was scheduled to be on a long-term outage until February 28, 2024.

As of January 6, some assets declared their default availability for January 13, i.e., the declared availability was set equal to, or close to, the asset's maximum capability (Table 5). The actual availabilities for the Fort Hills (FH1) and Nexen Inc #2 (NX02) assets were later lowered to reflect ambient temperatures. The availability of Christina Lake (MEG1) was later lowered to reflect site conditions, and the availability of Syncrude #1 (SCL1) was later lowered to reflect ambient temperatures, site conditions, and some generator outages at the site.

Table 5: Select available capability (AC) declarations for January 13 HE 20

	Maximum Capability	**AC as of January 6 at 00:00**	**AC as of January 12 at 17:00**	**Realized AC**	**Difference reason**
FH1	199	199	199	149	Default AC
MEG1	202	202	202	135	Default AC
SCL1	510	510	440	385	Forced outage
NX02	220	220	185	190	Default AC
CAS1	450	150	150	0	Forced outage
HRM	300	300	300	70	Forced outage
BRA	350	350	350	160	Forced outage
BOW1	320	311	248	185	Forced outage
EC01	120	120	112	0	Forced outage
Total	**2,671**	**2,362**	**2,183**	**1,274**	**-**

Cascade 1 (CAS1) was in the process of commissioning during the Alert. As of January 6 at 00:00 and January 12 at 17:00, the asset was expected to have 150 MW available for commissioning during the relevant hours of January 13. However, a forced outage at around 12:00 on January 13 meant the asset was unavailable during the EEA event.

At around 12:30 on January 10, the 300 MW HR Milner asset (HRM) tripped offline, but the outage was initially estimated by HRM operators to be short-lived. For example, at 22:10 on January 10, HRM was expected to return in HE 05 of January 11. HRM restarted on January 11 in HE 16 but tripped offline again in HE 01 of January 12.

HRM restarted again at around 19:00 on January 12 but operators were not able to bring the asset close to its full availability of 300 MW and instead were stuck at around 70 MW. However, it was not until closer to real-time that operators at HRM declared the asset would be largely unavailable for the EEA event on January 13.

Going into January 13, HRM remained derated to an available capability of 70 MW, but the expectation of HRM operators was that this would improve relatively quickly. For example, at 10:48 on January 13, the asset was expected to be fully available by 14:00. However, HR Milner remained heavily derated until late in the day on January 15. Table 6 provides the times at which HRM operators declared that the asset would be heavily derated during the hours surrounding the Alert. For example, at 14:46 HRM operators declared that the asset would be heavily derated for HE 18.

Table 6: HR Milner derate declaration times by hour ending (January 13)

Hour ending	Hour start time	Time derate declared
16	15:00	13:01
17	16:00	14:26
18	17:00	14:46
19	18:00	16:09
20	19:00	16:09
21	20:00	18:23

In addition, Genesee 1 suffered a forced derate beginning at around 17:15. This derate took the asset's generation from 400 MW down to 150 MW for a brief period prior to the Alert. Genesee 1 was back generating 400 MW by 18:30.

Due to the cold weather, icing restrictions derated some of the larger hydro generators in the province on the evening of January 13. For example, the Brazeau (BRA) asset was derated from 350 MW to 160 MW beginning at around 17:30.

At 19:45 on January 13, during the EEA event and about an hour after the Alert was issued, the 120 MW Cavalier asset tripped offline due to an unexpected forced outage.

1.4 Wind and solar generation

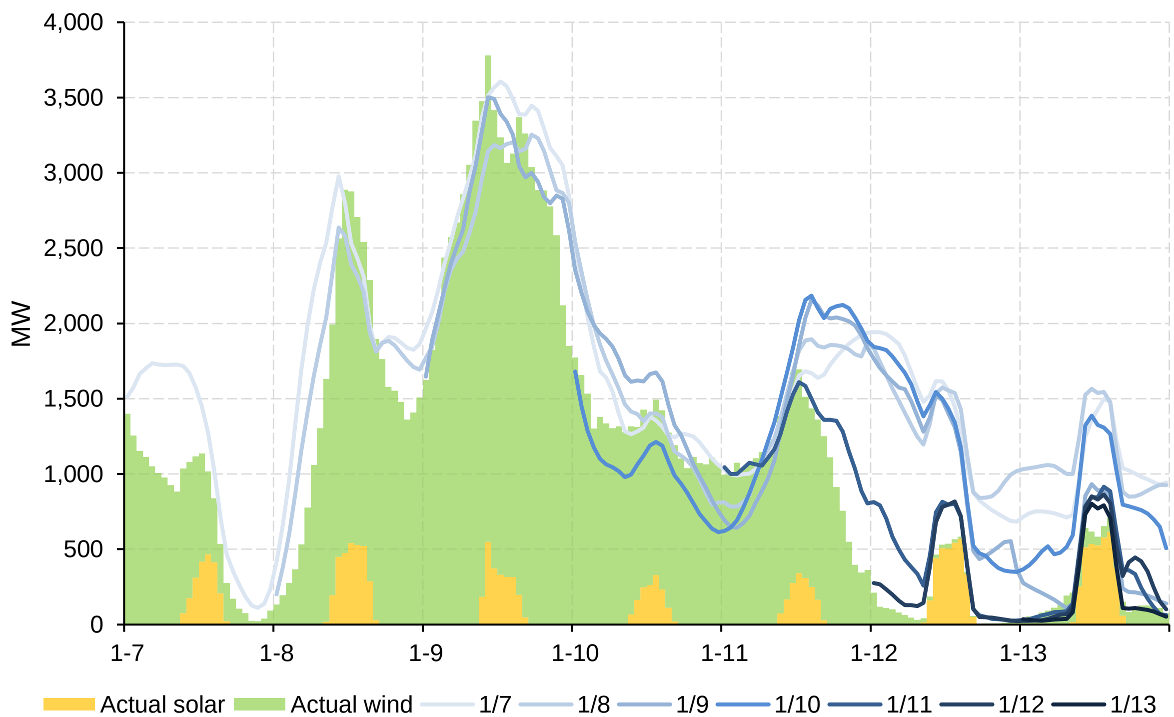
Early versions of the wind forecast for January 13 significantly over-predicted generation. However, the wind forecast gradually improved leading up to January 13, and actual generation, while low, consistently met or exceeded the forecasts made within 24 hours of real time. While the solar forecast over-predicted generation, this was not relevant during the time of peak scarcity, which occurred after sunset.

The AESO procures wind and solar forecasts over a 7-day forecast period. Within 12 hours of real time, the forecast updates every 10 minutes. The forecast is used for operations and is made publicly available.

Figure 10 shows wind and solar forecast versions as of midnight on each day from January 7 through 13. Early forecast versions performed well up until midday on January 11, when wind generation fell from approximately 1,350 MW to almost 0 MW. This drop off was first anticipated by the wind forecast version from January 11. Going into January 12, the difference between the January 11 forecast version and previous versions was approximately 1,000 MW.

Forecasts from January 11 to 13 correctly anticipated very low wind generation but overestimated peak solar generation by approximately 200 MW. The January 12 version incorrectly forecasted an increase in wind generation late in the afternoon on January 13.

Figure 10: Wind and solar forecasts and actual generation (January 7 to 13, 2024)



The following figures compare the 12-hour-ahead forecasts with actual generation for wind and solar on January 13. In these figures, the forecast version time is rolling to always show the outlook 12 hours ahead of real time. The 12-hour wind forecast predicted minimal generation and wind outperformed the forecast throughout the day. This resulted in a 200 MW positive forecast error in HE 10. However, the forecast over-predicted solar generation, resulting in a 200 MW negative forecast error in HE 12.

Figure 11: Actual and forecast wind generation on January 13, 2024

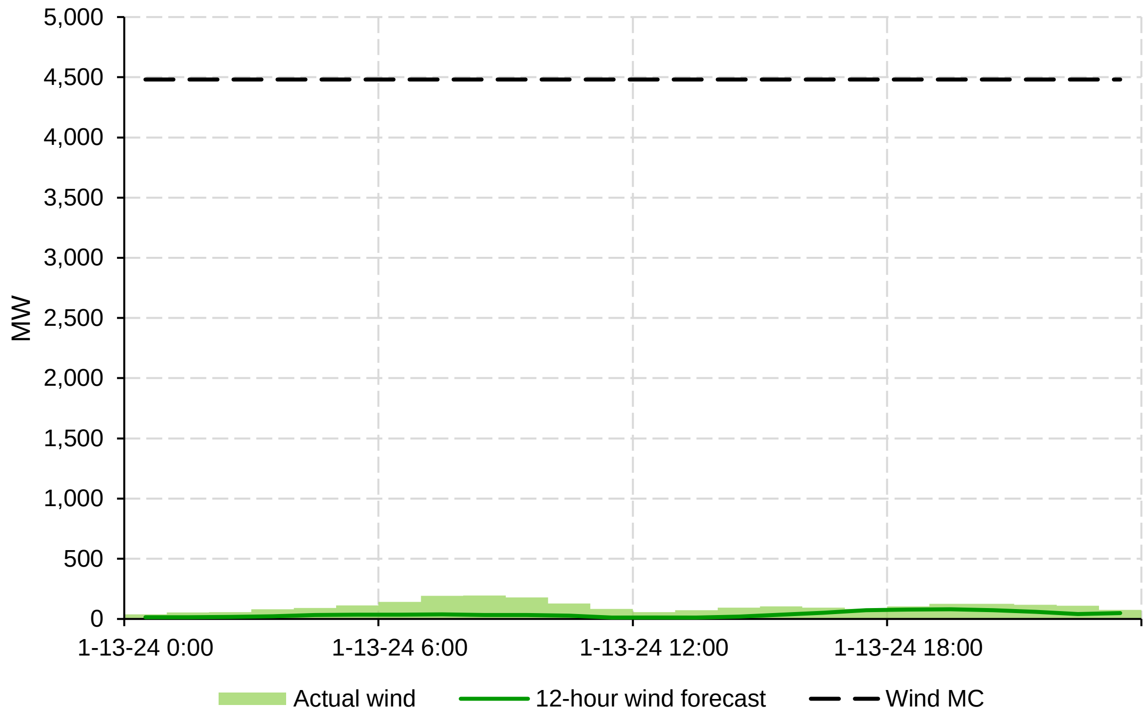
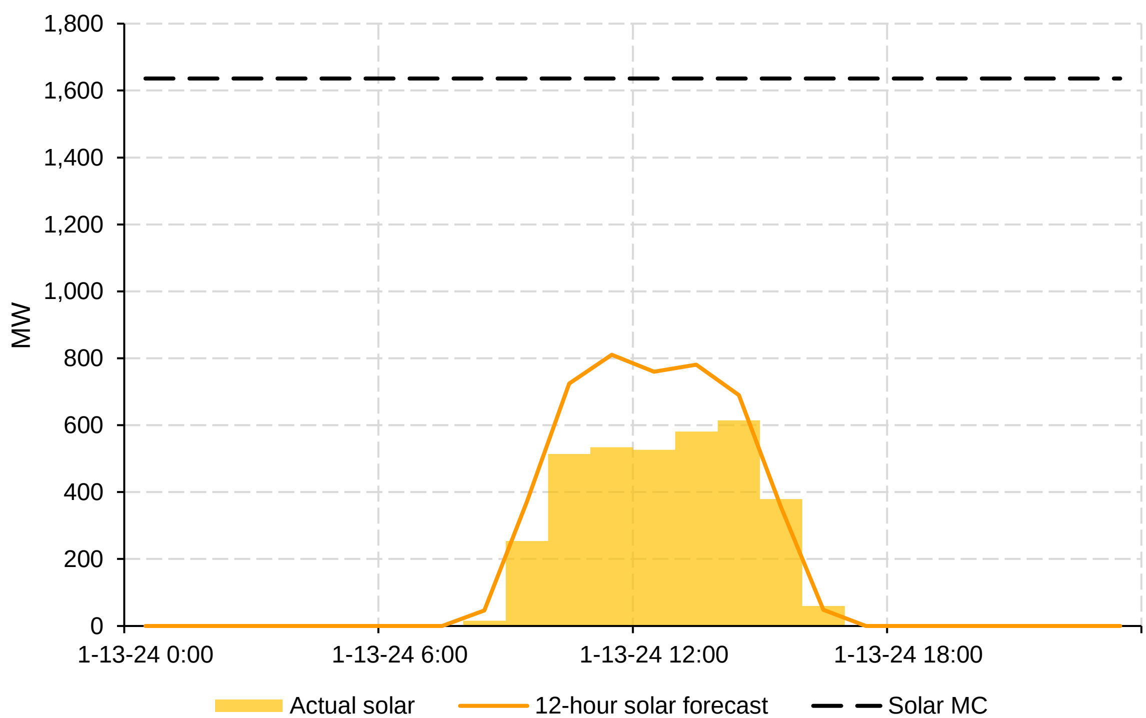
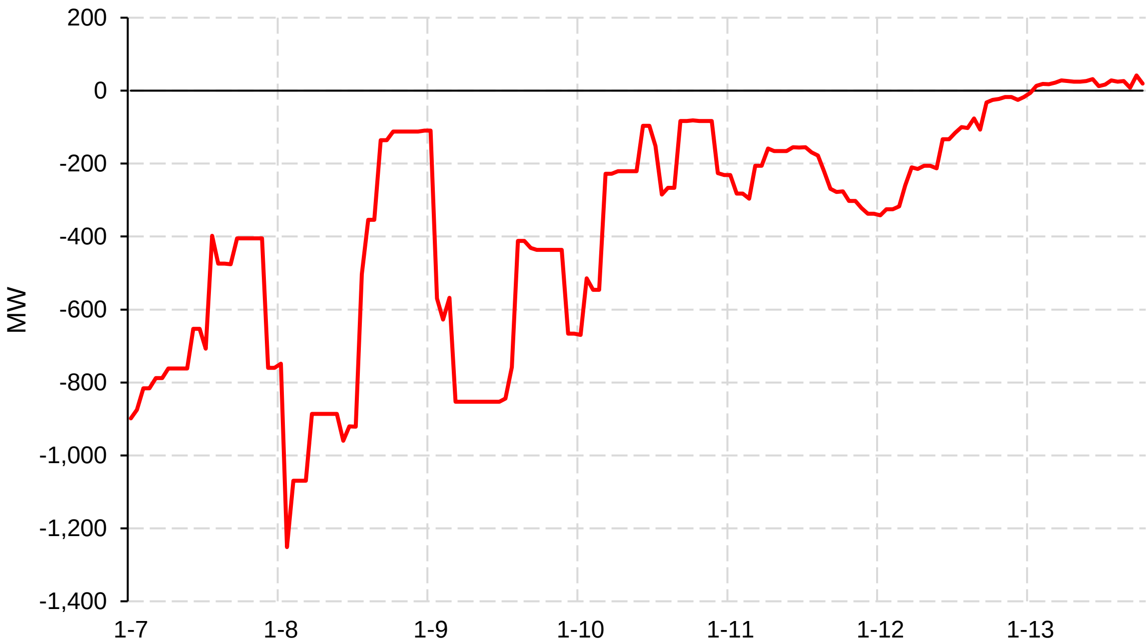


Figure 12: Actual and forecast solar generation on January 13, 2024



As shown in Figure 13, the wind forecast error for HE 19 on January 13 fluctuated in the week leading up to January 13, but was small by the evening of January 12. This was representative of all hours for the evening of January 13, with wind generation slightly outperforming recent versions of the forecast.

Figure 13: Development of wind forecast error for HE 19 on January 13, 2024



1.5 Adequacy reporting

> The Supply Adequacy Report was slow to signal increasing scarcity leading up to January 13, while the Market Supply Cushion Report was more effective despite issues with the underlying methodology at the time.

1.5.1 Supply Adequacy Report

The AESO publishes a forward-looking adequacy assessment called the Supply Adequacy Report, which rates supply adequacy by five numerical codes for each hour of the current and following six days. The Supply Adequacy Report updates every five minutes for future hours in the current day and every hour for the following six days. The codes, set out below, are determined using forecasts of several adequacy indicators, including demand, available capability, intermittent output, and import Available Transfer Capability (ATC).

0	= unable to maintain 3% reserve requirements	3	= 200 to 400 MW of supply available
1	= unable to maintain 6% reserve requirements	4	= greater than 400 MW of supply available
2	= 0 to 200 MW of supply available		

A code of 4 applies to all hours predicted to have at least 400 MW of additional supply available despite there still being a significant range of reliability risk. Specifically, hours coded at 4 could include supply surplus events and situations in which a single contingency could put the system in supply shortfall.

Table 7 shows a selection of report versions leading up to the Alert. Through 18:00 on January 12, the Supply Adequacy Report showed 4 for all hours on January 13. By midnight on January 13, the Supply Adequacy Report predicted mild supply tightness for January 13, HE 18, while HE 19 fluctuated between a 4 and a 3.

The supply outlook continued to worsen over January 13; however, it did not indicate a shortfall. As HE 18 began, the supply adequacy code for that hour was still 2, indicating up to 200 MW of supply available. By the end of HE 18, the intra-hour supply adequacy code was 0. At the time of the Alert, the intra-hour code and the code for the following hour (HE 19) were both 1. Through HE 20, the intra-hour code fluctuated between 1 and 2.

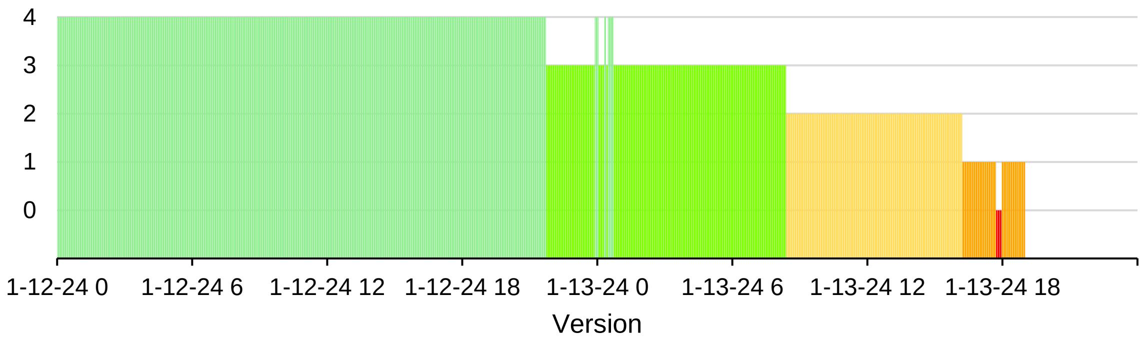
Table 7: Evolution of Supply Adequacy codes for January 13, 2024

	HE on January 13, 2024																							
Version	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1/12 18:00	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
1/13 00:00	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	3	4	4	4	4	4	4
1/13 06:00							4	4	4	4	4	4	4	4	4	4	4	2	3	3	4	4	4	4
1/13 12:00													4	4	4	4	3	2	2	3	3	4	4	4
1/13 18:00																			1	1	2	3	4	4
Realized[6]	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	2	0	1	1	2	4	4	4

Figure 14 shows how the supply adequacy code for HE 19 on January 13 evolved leading up to real time. Before the figure begins on January 12, the report had only indicated the maximum code of 4. The code first changed from 4 to 3 at 21:43 day ahead. The outlook worsened to 2 at 08:23 on January 13, 1 at 16:13, and finally 0 just before HE 19 began. Once HE 19 started, the outlook slightly improved back to a 1.

[6] Supply adequacy forecasts for a given hour continue to be updated in real time through to the end of that hour. Realized values indicate the minimum value posted in real time while the hour was unfolding.

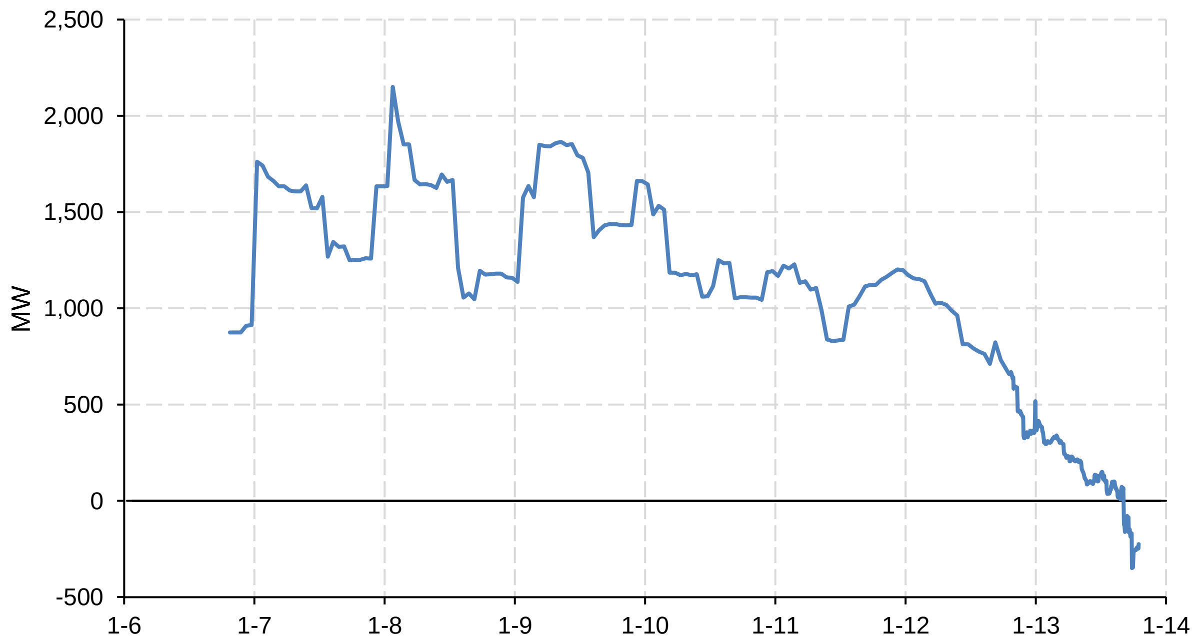
Figure 14: Evolution of Supply Adequacy code for HE 19 January 13, 2024



The Supply Adequacy Report did not anticipate the tight supply conditions on January 13 until the evening before. However, during the event there were no assets commercially offline, price responsive loads had already voluntarily curtailed, and imports were limited due to competition from other jurisdictions.

Figure 15 shows the underlying decline in supply adequacy starting on January 12, primarily due to unanticipated generation outages and wind and solar forecast error. While these factors can never be completely mitigated, the report is particularly vulnerable to them due to the narrowly defined supply bands. Had the Supply Adequacy Report signaled potential scarcity well before only 400 MW of available supply was expected, it would provide a better signal to the market and be less susceptible to sudden shifts based on forecast error and outages.

Figure 15: Evolution of Supply Adequacy MW for HE 19 January 13, 2024



1.5.2 Market Supply Cushion Report

In Q4 2023, the AESO began publishing the Market Supply Cushion Report to supplement the Supply Adequacy Report. According to the AESO, the Market Supply Cushion Report forecasts the energy in the merit order that remains available for dispatch after system load is served. It uses a subset of the variables used in the Supply Adequacy Report and replaces the use of available transfer capability on interties with a forecast of net imports/exports.

The AESO implemented updates to the Market Supply Cushion Report on June 20, 2024, as part of the unit commitment process under the *Supply Cushion Regulation*.[7] As of July 1, 2024, the Market Supply Cushion Report is now used to determine whether anticipated supply cushion falls below 932 MW, in which case the AESO must issue unit commitments to eligible long lead time assets. The MSA's analysis reflects the Market Supply Cushion Report as it was during the Alert and not the recently updated version.

Before the recent updates, the Market Supply Cushion Report assigned one of the following codes to each hour:

0	= 0 MW or less of market supply cushion	2	= above 200 up to 400 MW of market supply cushion
1	= above 0 up to 200 MW of market supply cushion	3	= greater than 400 MW of market supply cushion

It is not the AESO's practice to retain the Market Supply Cushion codes posted to its website. As with all other important public-facing data, the AESO should retain this information, including all published versions. The MSA has replicated them based on the following description of the calculation from the AESO:[8]

a) Available capability from all generating source assets in Alberta with a maximum capability equal to or greater than 5 MW with a start-up time less than or equal to one hour or with a submitted start time at or before the period being assessed;

plus

b) estimated output from aggregated generating facilities;

plus

c) a forecasted estimate of total net imports/exports on all interties;

minus

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[7] AESO Engage Section 202.6 Amended ID #2012-006R, *Calculations and Methodologies regarding Supply Adequacy* https://www.aesoengage.aeso.ca/section-2026-id

[8] Supply Adequacy & Market Supply Cushion Metadata http://ets.aeso.ca/Market/Reports/Manual/HelpText/current-supply-adequacy-metadata.pdf

d) the peak forecast load from the day-ahead forecast of Alberta internal load;

minus

e) constrained down generation, with the exception of constrained down aggregated generating facilities.

Table 8 shows a selection of report versions leading up to the Alert on January 13. In general, the Market Supply Cushion Report was more effective at anticipating the scarce conditions compared to the Supply Adequacy Report. Reduced adequacy was expected by 18:00 on January 12, with negative supply cushion for HE 18 predicted at approximately 06:00 on the morning of January 13.

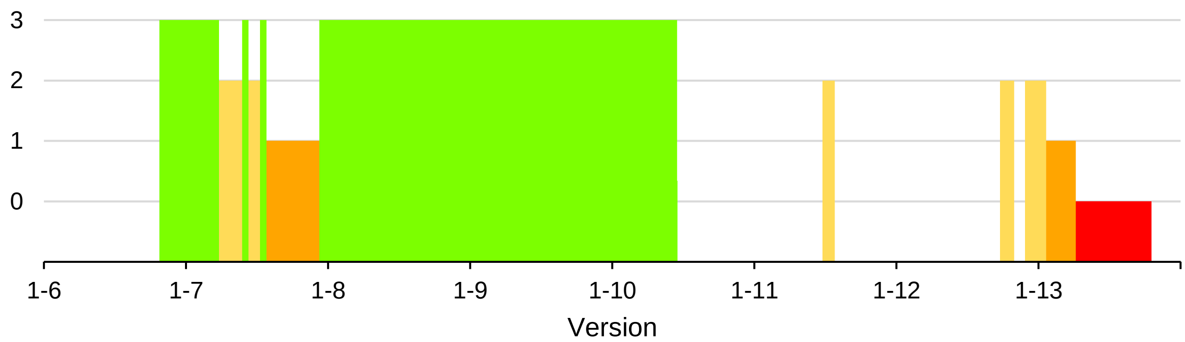
Table 8: Evolution of Market Supply Cushion codes for January 13, 2024

	HE on January 13, 2024																							
Version	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1/12 18:00	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	3	3	3	3	3
1/13 0:00	3	3	3	3	3	3	3	3	2	3	3	3	3	3	3	3	2	2	2	2	2	3	3	3
1/13 6:00							3	3	3	3	3	3	3	3	3	3	2	0	1	1	2	2	2	2
1/13 12:00													3	2	3	3	0	0	0	0	1	1	1	1
1/13 18:00																			0	0	0	0	1	1
Realized[9]	3	3	3	3	3	2	3	3	2	2	2	2	2	2	2	2	1	0	0	0	0	0	0	1

Figure 16 shows how the Market Supply Cushion code evolved leading up to HE 19 on January 13. The report predicted reduced supply cushion six days ahead, although the outlook improved shortly thereafter. By 23:00 on January 12, the Market Supply Cushion Report consistently predicted reduced supply cushion. The outlook developed similarly for the other hours of peak scarcity.

[9] Market supply cushion forecasts for a given hour continue to be updated in real time through to the end of that hour. Realized values indicate the minimum value posted in real time while the hour was unfolding.

Figure 16: Evolution of Market Supply Cushion code for HE 19 January 13, 2024



The MSA believes the methodology in place during the Alert did not accurately represent energy remaining in the merit order. However, these biases were countervailing, which is why the report was reasonably effective in anticipating tight supply conditions. The recently implemented amendments, including consideration of behind-the-fence generation and capacity used for contingency reserves, may improve the accuracy of the forecast. Further, the AESO has added categories between 400 MW and 1,000 MW of remaining supply cushion, which give a better indication of when supply may become scarce.

1.6 Operating reserves

Leading up to the Alert, the AESO needed to use up to 100% of contingency reserves to provide energy in order to balance supply and demand. Despite wind and solar generation being low and stable, the AESO maintained a relatively high volume of regulating reserves during the EEA event.

AESO system controllers call upon three types of operating reserve to address unexpected imbalances or lagged responses between supply and demand: regulating reserve, spinning reserve, and supplemental reserve.

Regulating reserve provides an instantaneous response to an imbalance of supply and demand. Spinning reserve and supplemental reserve are contingency reserves, used to maintain system balance when an unexpected event occurs. Spinning reserve (SR) is synchronized to the grid and provides capacity that the system controller can direct quickly given a sudden drop in supply. Supplemental reserve is not required to be synchronized but must be able to respond within 10 minutes if directed by the system controller. Supplemental reserves can be provided by both generation (SUPG) and load (SUPL).

The AESO buys operating reserves through day ahead auctions. In a contingency, the AESO issues directives to spinning and supplemental reserves to flow their capacity as energy to assist in meeting system needs.

In response to cold temperatures and high demand, on January 13 the AESO issued contingency reserve directives for a total of 160 minutes, between 16:17 and 18:56. Figure 17, Figure 18, and Figure 19 on the following page illustrate directed contingency reserve volumes relative to available dispatched volumes for the different products during this event.

At 18:44 on January 13, the Alert asked Albertans to reduce their electricity consumption. Leading up to the Alert, the AESO directed an average of 200 MW of spinning reserves, 121 MW of supplemental reserves from generation, and 88 MW of supplemental reserve from load.

From 17:32 to 17:37, the AESO directed all 463 MW of its available contingency reserve. Table 9 highlights the periods of time in which 100% of a particular contingency reserve product was directed. During this time, Alberta was not a consistent importer, and as a result additional products such as FFR or LSS were not armed.

Table 9: Maximum available volumes directed on, by product (January 13, 2024)

Product	% of Dispatched Volume Directed	Start Time	End Time	Duration (Minutes)	Average Directed Volume (MW)
SR	100%	17:21	17:37	17	258
SUPG	100%	17:32	18:37	66	117
SUPL	100%	16:17	18:56	160	88
All CR	**100%**	**17:32**	**17:37**	**6**	**463**

Figure 17: Spinning reserve directives (January 13, 2024)

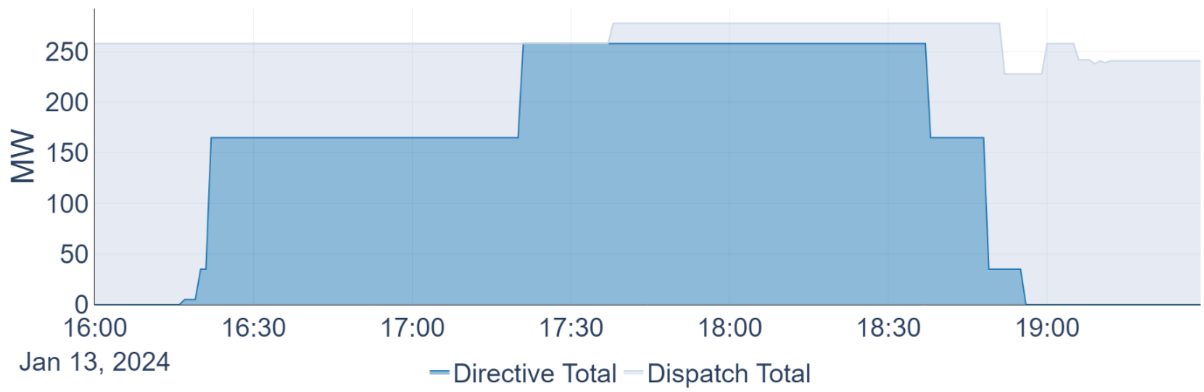


Figure 18: Supplemental generation directives (January 13, 2024)

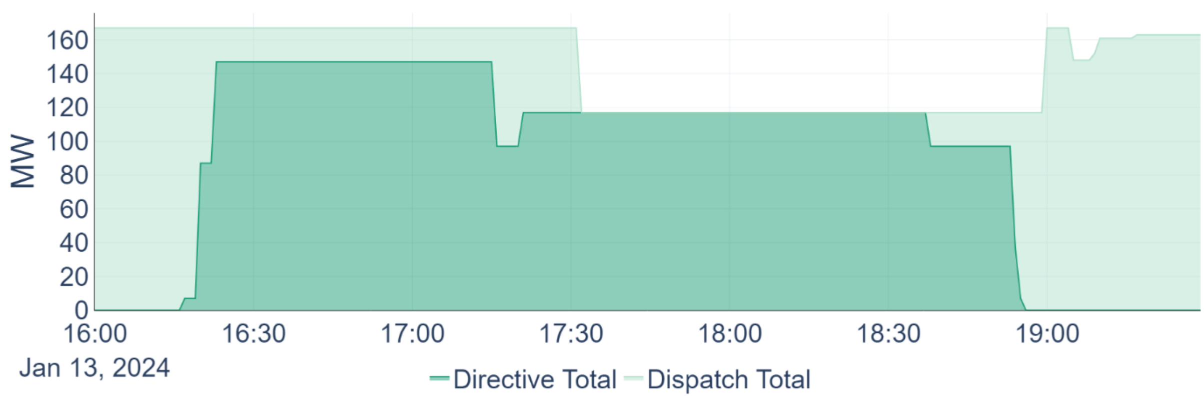
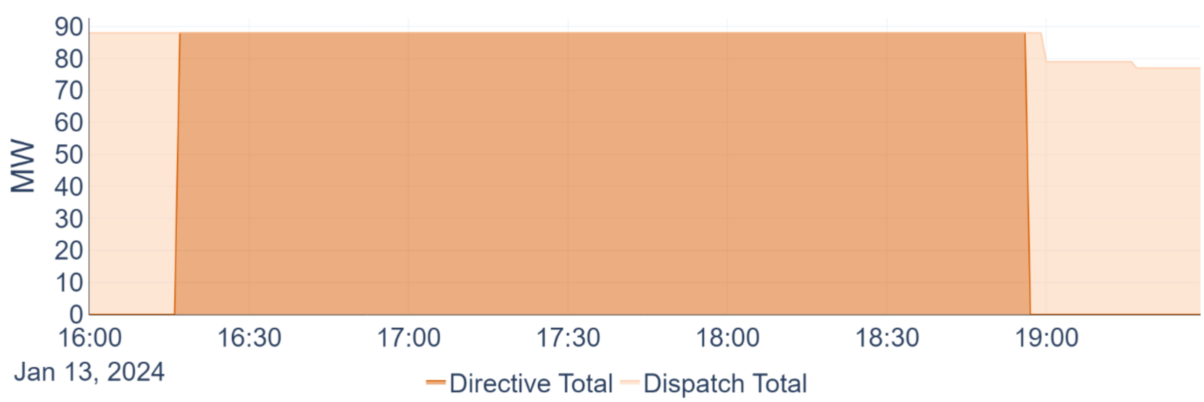


Figure 19: Supplemental load directives (January 13, 2024)

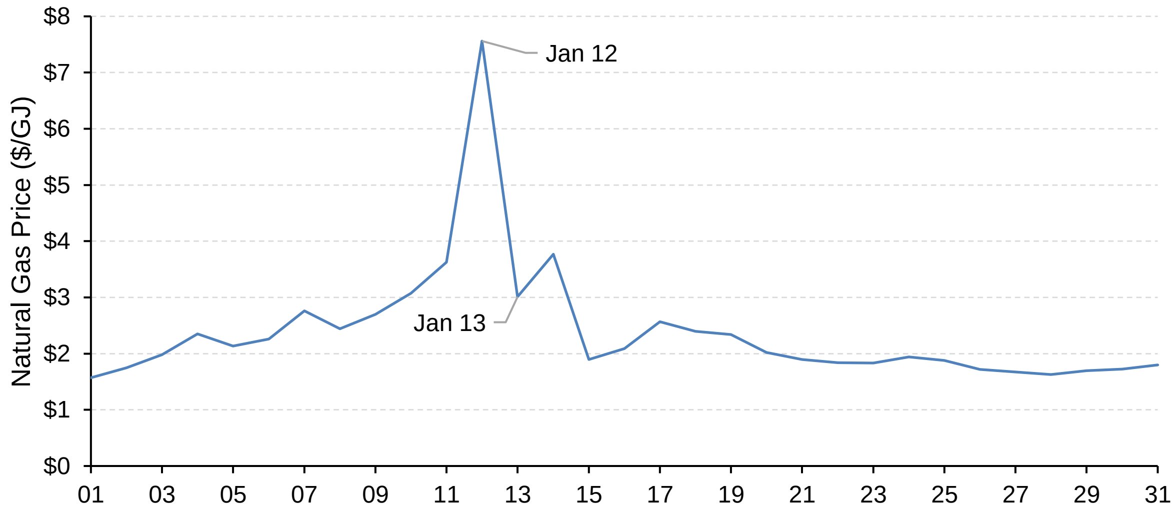


1.7 Natural gas market

Due to supply and demand conditions in the natural gas market on January 13, there was abnormally low pricing in the yesterday natural gas market. The supply of natural gas to thermal generators was not an issue for the January 13 EEA event.

The cold weather also increased the price of natural gas in Alberta as heating demands increased. On January 11, the same day price of natural gas averaged $3.63/GJ, but this increased to $7.56/GJ on January 12, an increase of 108% (Figure 20). Subsequently, natural gas prices fell back down, averaging $3.01/GJ on January 13. Natural gas supply to thermal generators was not an issue in the January 13 event.

Figure 20: Same day natural gas price (January 1 to 31, 2024)



There was downward pressure on natural gas prices on January 13 because of:

- increased storage withdrawals,
- a compressor station outage which reduced export capacity to BC, and
- reduced exports due to lower demand from Ontario.[10]

As a result of these factors, NGTL needed to reduce the line pack by reducing the amount of natural gas on the system. Normal tolerance rules on NGTL are -2/+2 which means that participants can underdeliver / over withdraw by -2% or overdeliver / under withdraw by +2%. However, this can be reduced to -1/+1 due to system conditions, as was the case on January 13.

[10] TC Energy: NGTL System and Foothills Pipelines Ltd., Customer Operations Meeting – February 1, 2024

The yesterday market for natural gas is a financial market for clearing volumes from yesterday that were under or over the schedule. At 10:00 on January 13, NGTL changed the tolerance from -1/+1 to -2/0 meaning that participants were allowed to undersupply or over withdraw by 2% but were not allowed to oversupply or under withdraw. This had impacts on the yesterday natural gas market because the extra natural gas from yesterday had nowhere to go. As a result, natural gas prices in the yesterday market for January 12 fell to negative $100/GJ, an abnormally low price.

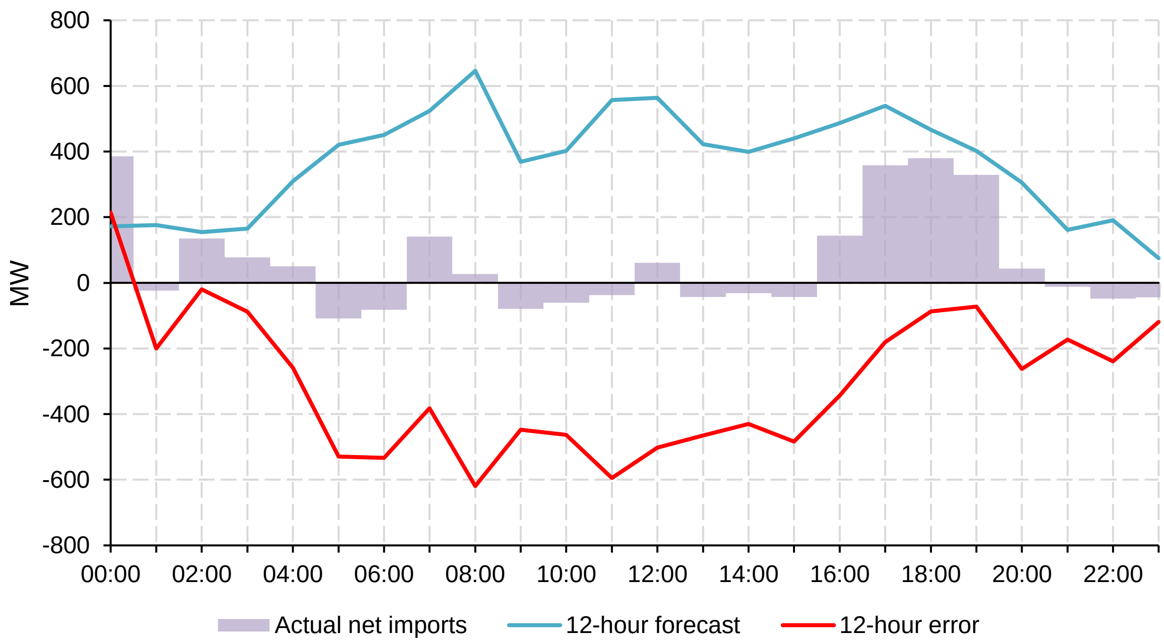
1.8 Interties and other jurisdictions

Prices in Mid-Columbia (Mid-C) were higher than Alberta over January 13. As a result, Alberta was a net exporter leading up to the event until exports were curtailed by the AESO at the beginning of the EEA 3. Although there were limited market-based imports, Alberta received emergency imports from BC and Saskatchewan in addition to imports though the Northwest Power Pool Reserve Sharing Program.

The AESO forecasts imports 10 days ahead of delivery. The forecast updates every 30 minutes. This import forecast is used to calculate the Market Supply Cushion metric discussed in section 1.5.2.

Figure 21 shows the import forecast, actual net imports, and forecast error on January 13 using the forecast version 12 hours ahead of real time. Forecast error is measured as the actual minus the forecast, so negative values indicate that there were fewer imports than forecast.

Figure 21: Net imports vs. forecast on January 13, 2024



The 12-hour import forecast over-predicted imports, in some cases by approximately 600 MW. During peak scarcity on January 13, from HE 17 to HE 20, the forecast error was smaller, ranging from approximately 75 MW to 350 MW. This aligns with the time period over which Alberta was receiving emergency and reserve-sharing imports, which are discussed in more detail below.

Figure 22 illustrates the evolution of the forecast error for HE 17 over time. While the 12-hour forecast error was large, the forecast improved leading up to real time.

Figure 22: Net import forecast for HE 17 on January 13, 2024

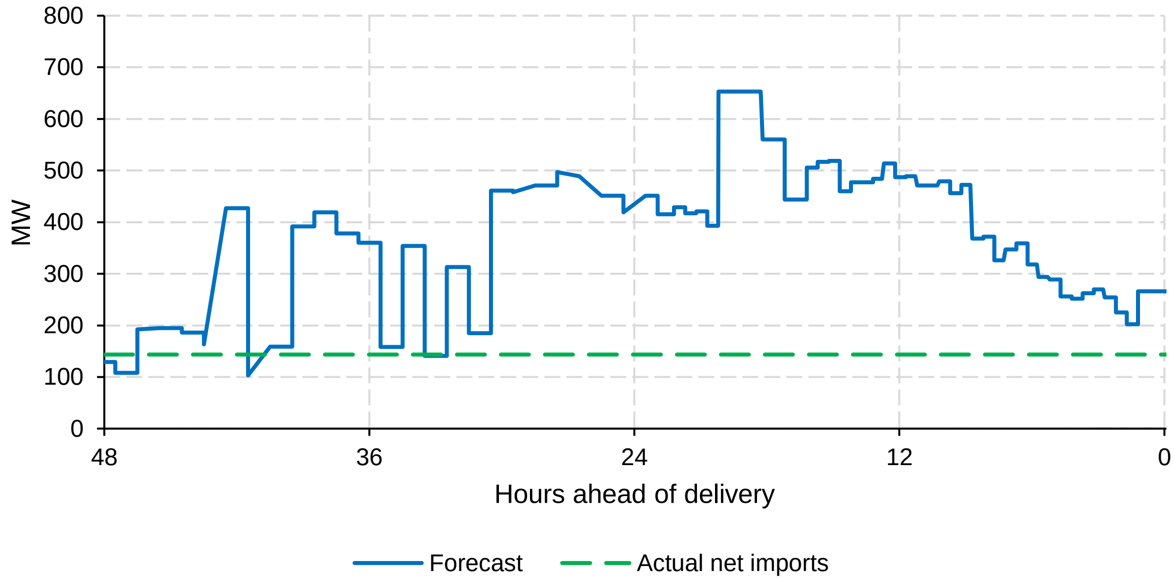
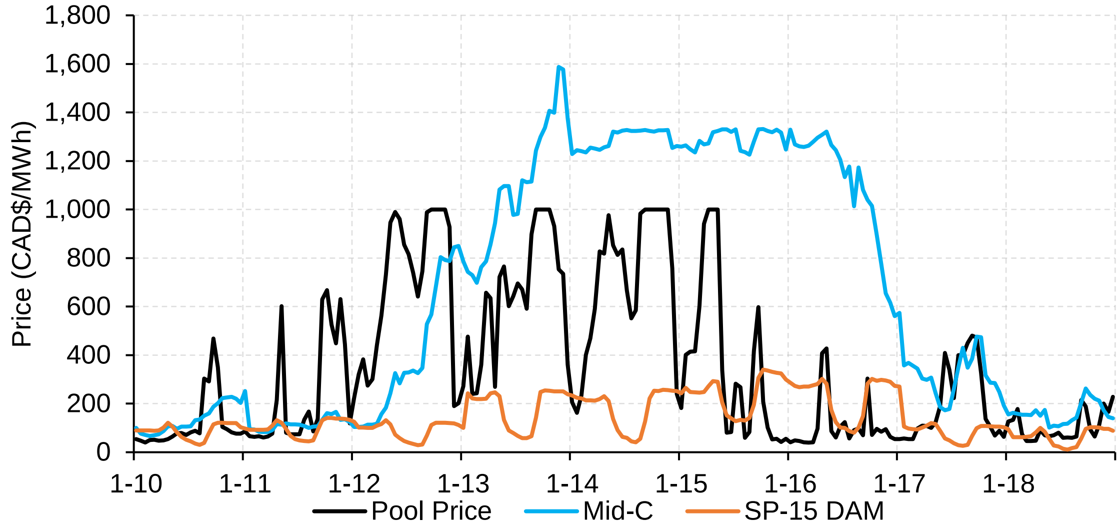


Figure 23 compares hourly power prices in Alberta, Mid-C, and California (SP-15) over January 10 to 18. Mid-C prices rose to a maximum of CAD$1,587/MWh on January 13, with high prices continuing through to January 16. The U.S. Northwest experienced drastically low temperatures which led to record high demand and reliability issues in certain Balancing Authorities[11]. From January 13 to 15, EEA events occurred in four Balancing Authorities across the U.S. Northwest.[12]

[11] Balancing authorities are the responsible entities that integrate resource plans ahead of time, maintain demand and resource balance within a Balancing Authority Area, and support interconnection frequency in real time (NERC).

[12] WPP Assessment of January 2024 Cold Weather Event

Figure 23: Hourly power prices in Alberta, Mid-C and SP-15 California (January 10 to 18, 2024)



As shown in Figure 23, the Mid-C price was significantly higher than prices in Alberta for all hours of January 13, with the daily price differential between Alberta and Mid-C averaging -$442/MWh. The price differential across different markets is a driver of intertie flows and resulted in net exports on the Montana Alberta Tie Line (MATL) over January 13, and relatively low net imports on the BC intertie.

Figure 24 shows prices, hourly intertie volumes, and joint capability on BC/MATL. BC/MATL import capability on January 13 averaged 440 MW and export capability averaged 935 MW except during the EEA 3 when exports were prohibited. Over the course of the day, flows on MATL averaged 89 MW of net exports and flows on the BC intertie averaged 62 MW of net imports. Import volumes on January 13 were much less than intertie capability, given higher prices and similar tight market conditions in Mid-C.

Figure 25 shows prices, hourly intertie volumes, and capability of the Saskatchewan (SK) intertie. Over January 13, import ATC on the SK intertie averaged 142 MW and export ATC averaged 140 MW; however, exports were prohibited during the EEA 3 event. On January 13, the import ATC of the SK intertie was increased to 153 MW on an emergency basis;[13] it had been largely derated to 90 MW since April 12, 2023. Over the course of the day, flows on SK averaged 88 MW of net imports.

[13] AESO system controller call 9349 on January 13, 2024, at 15:55:24

Figure 24: Hourly import (+ve) and export (-ve) volumes on BC/MATL, and price differential between Alberta and Mid-C (January 12 to 16)

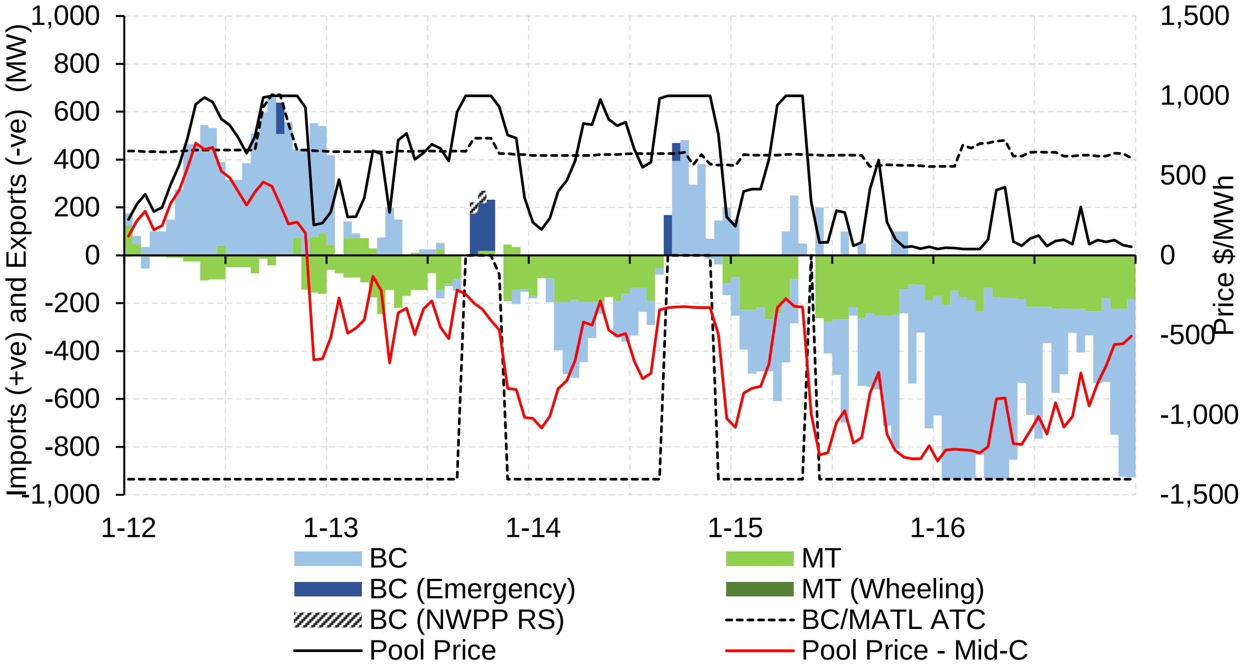
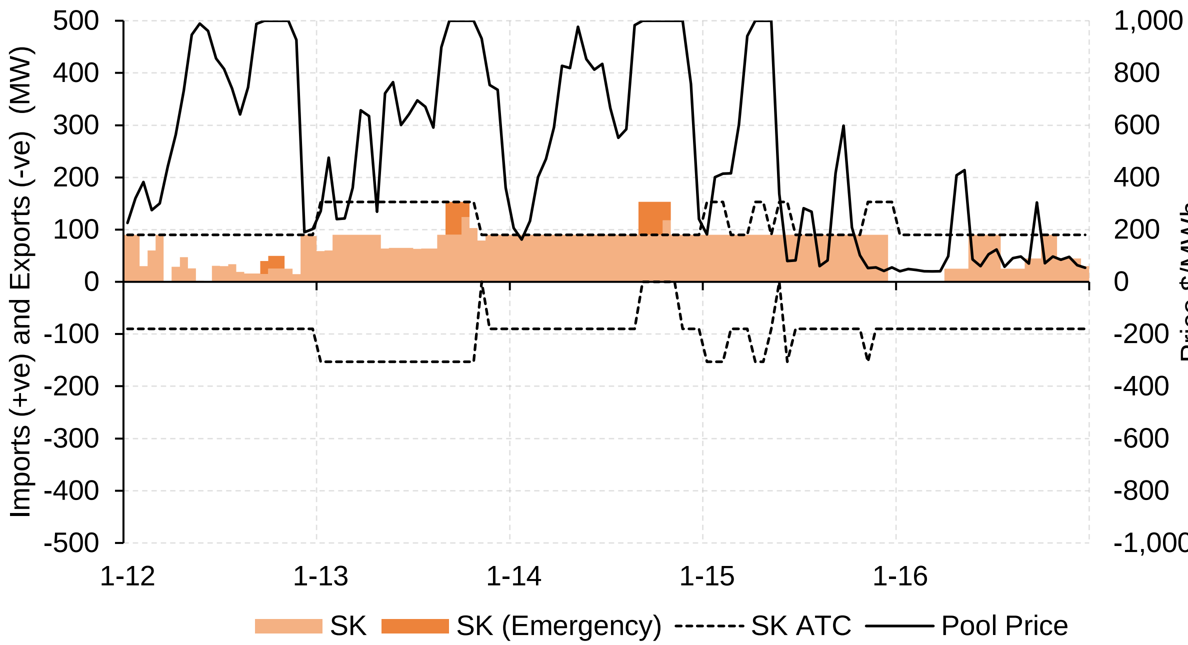


Figure 25: Hourly import (+ve) and export (-ve) volumes on SK, and the average pool price (January 12 to 16)



At 15:30 on January 13, when the EEA 3 event began, 60 MW of net exports were scheduled on the BC intertie, 119 MW of net exports were scheduled on MATL, and 90 MW of net imports were scheduled on the SK intertie. At 15:33, the AESO cut export e-Tags applicable to the upcoming

hour (HE 17) to 0 MW and at 15:49, the AESO cut e-Tags for the current hour (HE 16) to 0 MW. For HE 16 though HE 21 (the hours spanning the EEA 3 event), offers/bids on the BC intertie and MATL were in the direction of net exports; however, they were not able to materialize as the AESO prohibited exports for those hours. Offers/bids on the SK intertie were in the direction of net imports, with no export bids.

Over the event the only import offers were a 10 MW import offer on the BC intertie and up to a 57 MW import offer on MATL. However, these offers did not materialize into energy delivered. At 12:43 on January 13, the e-Tag associated with a 10 MW offer on the BC intertie was adjusted to 0 MW for HE 16 through HE 22; however, the corresponding import offer remained at 10 MW. The e-Tag associated with a 57 MW offer on MATL for HE 17 was curtailed to 0 MW by an external Balancing Authority, and the AESO curtailed the e-tag associated with an 18 MW import offer on MATL for HE 21.

Beginning in HE 17, Alberta began receiving emergency imports from Saskatchewan, and the full 153 MW import ATC of the SK intertie was used through HE 19. During HE 20, the SK intertie returned to 90 MW import ATC, and imports were curtailed to this limit (Figure 25).

Beginning in HE 18, Alberta began receiving emergency imports from BC in the range of 100 MW to 260 MW through HE 20. At 17:33 the AESO made a request for 150 MW of Northwest Power Pool reserve sharing imports which lasted until 18:29 (Figure 24).[14]

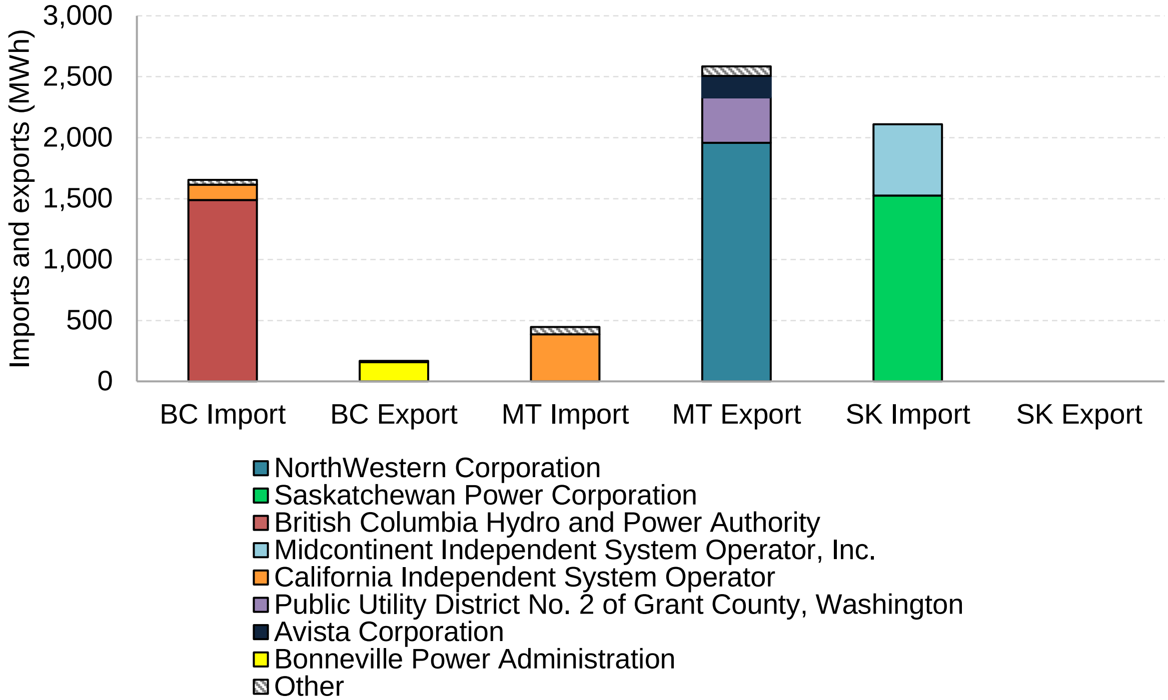
Figure 26 shows import volumes on January 13 by the point of receipt (POR)[15] and export volumes by the point of delivery (POD).[16] The Balancing Authority regions directly connected with Alberta generally have a high share of import and export flows, however, given the reliability issues across jurisdictions this was not always the case on January 13. Although the total energy delivered was relatively low, 87% of imports through MATL on January 13 originated from California, and 94% of exports on the BC intertie were delivered to Bonneville Power Administration.

[14] AESO system controller Shortfall Management January 13, 2024 document

[15] POR is the point on the electric system at which electricity is received.

[16] POD is the point on the electric system where electricity is delivered.

Figure 26: Interchange point of receipt (imports) and point of delivery (exports) for interchange volumes by Balancing Authority (January 13, 2024)



2 APRIL 2024 LOAD SHED EVENT

2.1 Event summary

- The AESO issued 244 MW of load shed instructions at 08:53 (which is in HE 09) on April 5, the first load shed event in Alberta since 2013. Load shed was cancelled at 09:19. Despite demand in HE 09 being only 9,895 MW, there was a high amount of thermal generator outages and low wind generation, which reduced supply.

- Peak demand on April 5 was low, at 10,195 MW, which is 18% less than the record set on January 11. Two days earlier, pool prices were $0/MWh while demand was approximately 90 MW higher.

- Outages at Shepard, Muskeg River, Mahkeses, Cloverbar 3, Nexen Inc #1, Sundance 6, Genesee 2, Genesee Repower 1, Cascade 1, and Keephills 2; and several others contributed to approximately 4,000 MW of reduced supply.

- Battle River 5 was commercially offline during the load shed event and declared a forced outage shortly thereafter.

- Wind generation ramped down overnight leading up to the load shed, resulting in approximately 400 MW less supply than was forecasted as of midnight on April 5.

- The Supply Adequacy Report was slow to react to changing supply conditions, while the Market Supply Cushion Report outlook began to signal reduced supply days before the event and continued declining as worsening factors developed overnight.

- 100% of spinning reserves were directed on for 23 minutes and 100% of supplemental reserves were directed on for 156 minutes. These periods coincided for 23 minutes, during which time all contingency reserves were directed to provide energy.

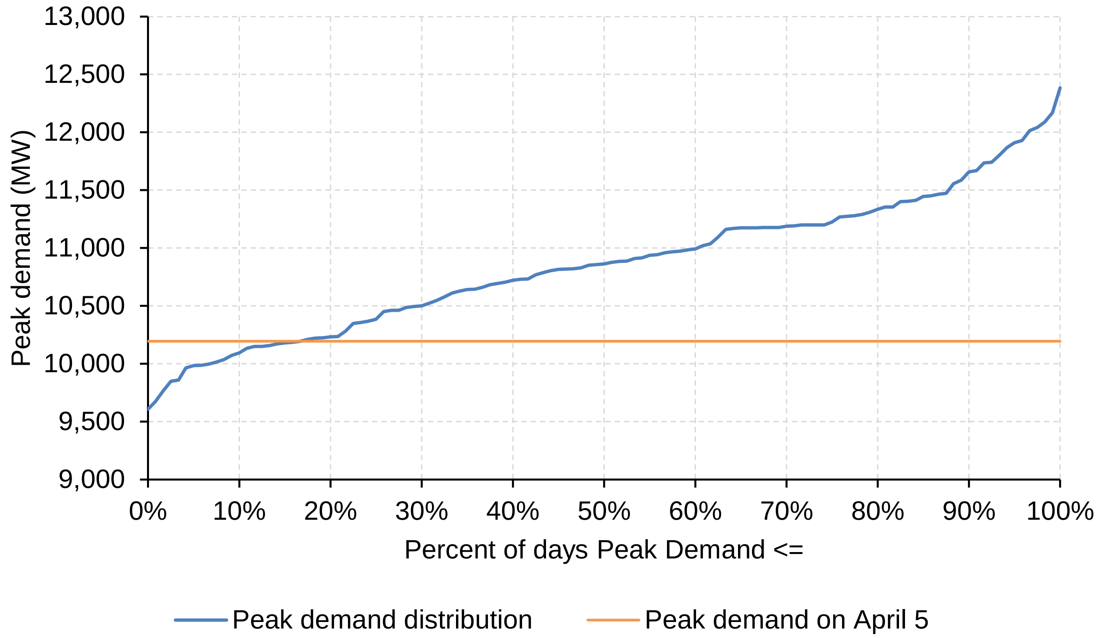
- Alberta prices were higher than in other jurisdictions, and as a result import capability was fully used through the EEA 3 event. Availability of LSS was limited as loads remained off due to high pool prices. Surrounding the load shed, Alberta received Northwest Power Pool Reserve Sharing imports.

2.2 Demand

> Electricity demand was relatively low on April 5 as prevailing temperatures were close to 0°C across Alberta. However, on April 5 the AESO shed firm load for the first time since 2013. Transmission and distribution companies across the province were directed by the AESO to reduce load by a total of 244 MW.

The load shed event on April 5 was not driven by high demand. Demand on April 5 peaked at 10,195 MW, which is 18% less than the record set on January 11. Figure 27 plots the distribution of daily peak demand from January 1 to April 30, 2024. Peak demand on April 5 was at the 17th percentile illustrating that it was a low demand day.

Figure 27: Peak demand duration curve (January 1 to April 30, 2024)



Demand on April 5 was low as temperatures were relatively moderate. Temperatures in Calgary averaged -0.6°C over the day, temperatures in Edmonton averaged 0.5°C, and temperatures in Fort McMurray averaged -1.0°C (Table 10).

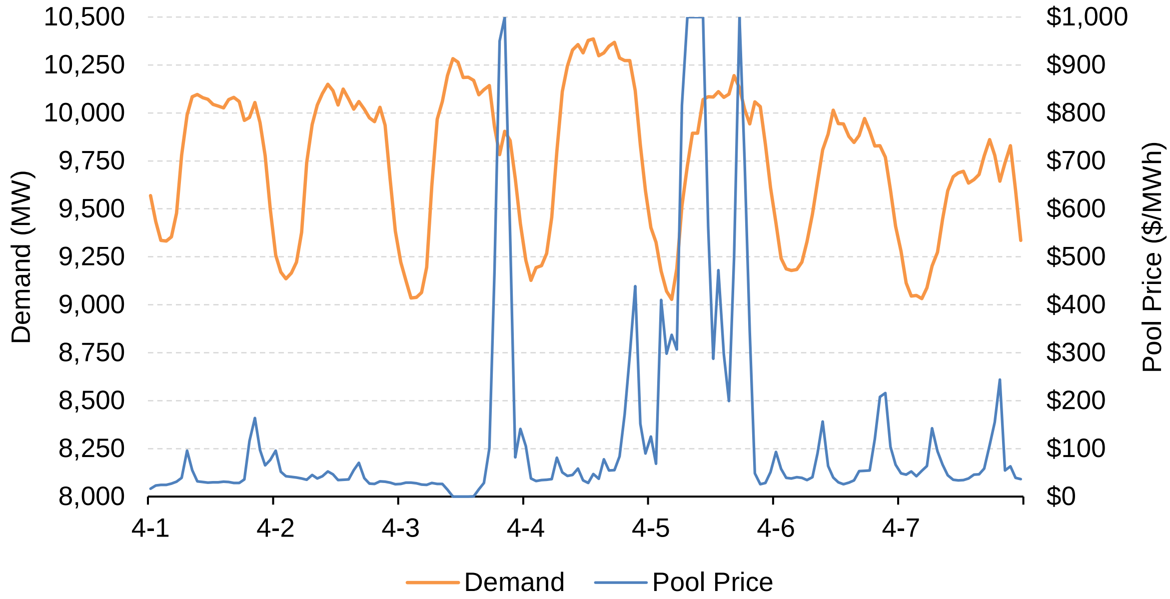
Table 10: Temperatures in Calgary, Edmonton, and Fort McMurray (°C) (April 5)

	Calgary	**Edmonton**	**Fort McMurray**
Average	-0.6	0.5	-1.0
Maximum	1.1	1.6	0.7
Minimum	-2	-0.9	-4

Figure 28 illustrates demand and pool price over the course of April 1 to 7. The high pool prices over this period were not driven by high demand. For example, on April 3, pool prices were $0/MWh when demand was 10,283 MW and prices were $999.99/MWh when demand was lower at 9,904 MW. Rather than being demand driven, these price differences were largely driven by changes in wind and solar generation and an outage at Genesee 2.

On April 5, the EEA 3 and load shed event occurred during the morning ramp up in demand, so demand was low compared to later in the day. In addition, demand overall was lower than the previous day when prices were lower and there was no EEA event.

Figure 28: Hourly demand and pool price (April 1 to 7)



2.2.1 Actual and forecast demand

The AESO's day-ahead forecast of demand performed well during the April 5 event (Figure 29). Over the course of April 5, the average absolute forecast error was low at 41 MW or 0.4% of average demand.

Figure 29: Hourly demand, day-ahead forecast of demand, and pool price (April 5)

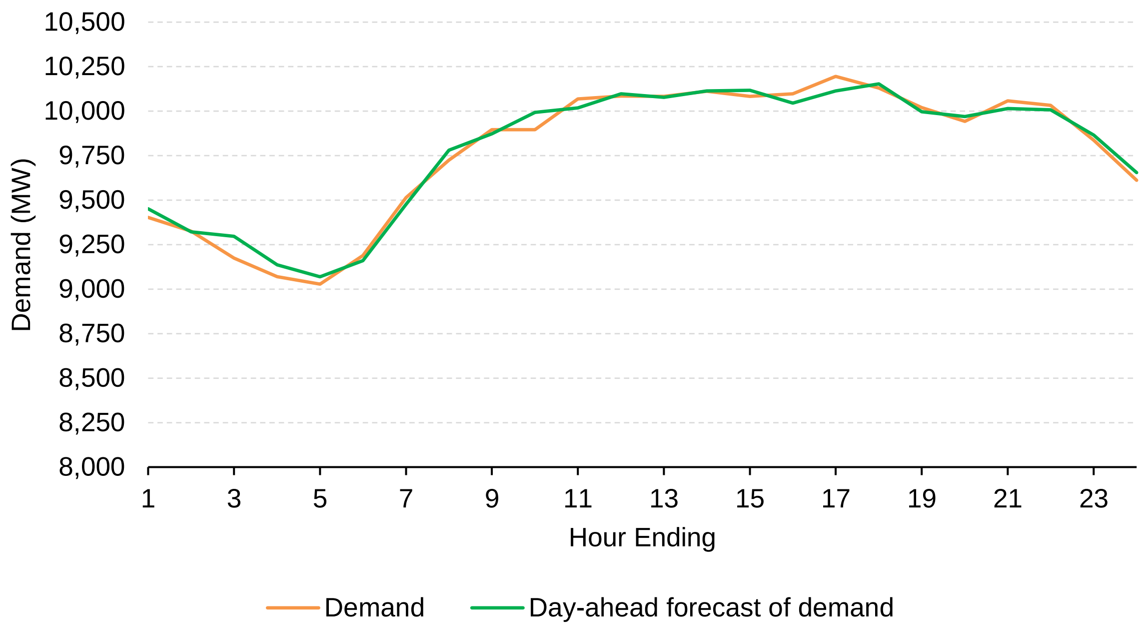


Table 11 provides the forecast errors for select hours around the EEA 3 event. The AESO over forecast demand for HE 10 by 97 MW, but an over forecast is to be expected given that load shed occurred in that hour.

Figure 29: Hourly demand, day-ahead forecast of demand, and pool price (April 5)

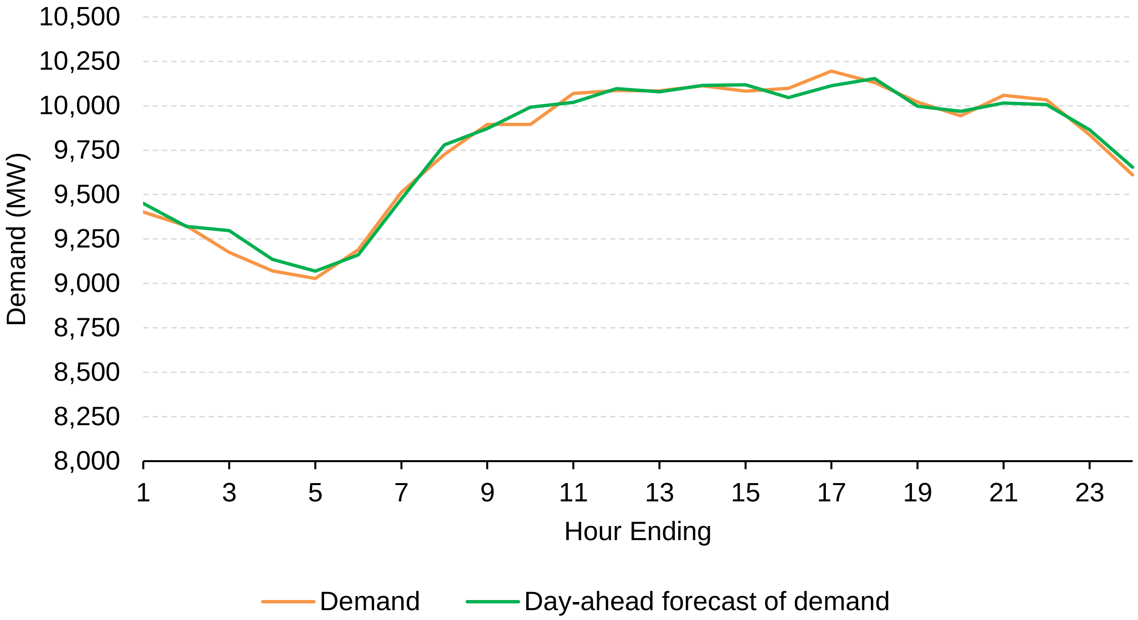


Table 11: Pool price, demand, and forecast demand for select hours (April 5)

Date	Hour ending	Pool Price ($/MWh)	Demand (MW)	Day-ahead forecast of demand (MW)	Forecast error (MW)
4/5/2024	6	$306.59	9,189	9,160	-29
4/5/2024	7	$815.84	9,514	9,476	-38
4/5/2024	8	$999.99	9,725	9,780	55
4/5/2024	9	$999.99	9,895	9,872	-23
4/5/2024	10	$999.99	9,895	9,992	97
4/5/2024	11	$999.99	10,069	10,018	-51
4/5/2024	12	$563.84	10,085	10,097	12

2.2.2 Load shed

At 06:49 on April 5 the AESO declared an EEA 3. At around 07:00, the AESO requested 3% voltage reductions from some distribution facility owners and requested load shed preparations across the province.[17] Due to further declines in available supply, the AESO directed load shed

[17] AESO system controller calls 3294, 3298, 3301-3305, and 3307 on April 5, 2024 from 06:54:21 to 07:07:58.

beginning at 08:53, issuing the following load shed instructions to transmission and distribution companies in Alberta:

Table 12: Load shed directives sent at 08:53

	Load shed directive (MW)
AltaLink	108
ATCO	62
ENMAX	40
EPCOR	34
Total	**244**

Table 13 provides the load changes observed in different planning regions following the load shed directives. The load shed affected some regions more than others. For example, load in the central region fell by 99 MW or 6% while load in Edmonton fell by 12 MW or 1%.

Table 13: Load changes by planning region around the load shed event on April 5

Region	**Load at 8:50 (MW)**	**Load at 09:03 (MW)**	**Change (MW)**	**Change (%)**
Northeast	2,967	2,909	-58	-2%
Edmonton	1,815	1,804	-12	-1%
Central	1,537	1,438	-99	-6%
Calgary	1,322	1,277	-45	-3%
South	1,132	1,104	-28	-2%
Northwest	952	944	-7	-1%
Total	**9,725**	**9,476**	**-248**	**-3%**

At 09:05 the AESO reduced the load shed amounts to the following:

Table 14: Load shed directives sent at 09:05

	Load shed (MW)
AltaLink	65
ATCO	37
ENMAX	24
EPCOR	21
Total	**147**

The AESO cancelled the load shed directives at 09:19 on April 5.

2.2.3 Price responsive load

In the week leading up to the load shed, price responsive loads consumed up to approximately 225 MW in aggregate and reduced their load during peak periods. During the high prices on April 3, these loads curtailed down to approximately 25 MW, a 200 MW reduction compared to their peak.

Figure 30: Price responsive load from March 30 to April 5, 2024

Going into April 5, price responsive loads were already consuming below their typical levels and as such further reductions from these loads were limited. As the supply conditions continued to worsen overnight, their consumption fell to approximately 30 MW and stayed low throughout the day until pool prices fell in the evening.

2.3 Outages

Thermal generator outages were the main factor behind the load shed event on April 5. A planned outage at Shepard, the largest generator in the province, combined with outages at Muskeg River, Mahkeses, Cloverbar 3, and Nexen 1 to reduce supply. There were also several forced outages including at Sundance 6, Genesee 2, Cascade 1, Genesee Repower 1, and Keephills 2. In addition, the Battle River 5 asset was commercially offline during the April 5 load shed event.

In early April, Shepard (EGC1), the largest generating asset in the province at 868 MW, was offline on a planned outage. This planned outage was scheduled two years in advance of the EEA event on April 5 (Table 15).

Muskeg River (MKR1) also had a planned outage on April 5 scheduled well in advance, as one of the asset's gas turbines was offline.

Similarly, Mahkeses (IOR1) had a planned outage at one of its gas turbines, meaning the asset was derated by 113 MW on April 5.

Cloverbar 3 (ENC3, 101 MW) was offline on April 5, having been on an extended outage that was scheduled 60 days in advance of the EEA event.

There was a derate at Nexen Inc #1 (120 MW) as one of the asset's two gas turbines was not operating on April 5. This was part of an extended derate and was scheduled 52 days in advance of the EEA event on April 5.

Sundance 6 was taken offline on April 2 for a forced outage that lasted until the evening of April 5. This outage was scheduled on the morning of March 30, six days ahead of the EEA event on April 5.

Genesee 2 was taken offline on April 3 for a forced outage that lasted until the morning of April 5. This outage was scheduled on the evening of April 3, or 1.6 days ahead of the EEA event on April 5.

Poplar Creek (SCR5), Firebag (SCR6), and Syncrude #1 were all derated on April 5 due to generator outages, site conditions, and ambient temperatures. Outages at these three large cogeneration assets totalled close to 500 MW and were scheduled day-ahead.

Table 15: Outages on April 5 that were scheduled in advance

Asset short name	Outage (MW)	Scheduled	Notice (days)
EGC1	868	4/1/2022 02:53	735
MKR1	109	9/21/2022 14:46	562
IOR1	113	2/2/2024 10:36	63
ENC3	101	2/5/2024 01:26	60
NX01	66	2/13/2024 14:06	52
SD6	401	3/30/2024 08:12	6
GN2	420	4/3/2024 17:48	1.6
SCL1	170	4/4/2024 06:26	1.1
SCR5	186	4/4/2024 06:27	1.1
SCR6	137	4/4/2024 06:28	1.1
Total	**2,571**	-	-

At 13:44 on April 4, Sheerness 1 scheduled to start up on the morning of April 5 after being commercially offline. The asset came online at around 04:00 and was fully available for dispatch at 08:07. The start-up time for Sheerness 1 was entered as a default value of 12 hours; however,

the asset took around 14 hours to come online. Additionally, the asset took a further 4 hours to be fully dispatchable; its submitted ramp rate was 6.5 MW/min, which means its entire 400 MW capability should take approximately 60 minutes to be fully dispatchable. To manage long lead time assets effectively, the AESO needs accurate physical parameter submissions, including start-up time and ramp rate.

Battle River 5 had not submitted a start time. Therefore, Battle River 5 was commercially offline during the April 5 load shed event. At 10:09 on April 5, after the load shed but during the EEA 3 event, a forced outage was declared at Battle River 5 as the unit was being prepared to start-up.

There were several forced outages and derates that were scheduled after 17:00 on April 4. Table 16 provides the declared available capability for April 5 HE 10 as of April 4 at 17:00 and compares this to the realized availability for the listed assets.

As of April 4 at 17:00, the Genesee 1 (GN1) asset was scheduled to be available for 400 MW and the Genesee Repower 1 (GNR1) asset was scheduled to be available for 376 MW. The MSA's understanding is that these assets would not typically operate at close to full capacity at the same time. Nevertheless, at around 02:30 on April 5, Genesee Repower 1 tripped offline and was subsequently stated out for the relevant morning hours of April 5.

Table 16: Select available capability declarations for HE 10 of April 5, 2024

Asset	Maximum Capability	AC as of 17:00 on April 4	AC realized	AC difference	Difference reason
CAS1	450	443	0	443	Forced outage
GNR1	411	376	0	376	Forced outage
MEG1	202	202	110	92	Default AC
HRM	300	300	260	40	Default AC
IOR2	195	185	149	36	Default AC
KH2	395	395	0	395	Forced outage
Total	**1,953**	**1,901**	**519**	**1,382**	**-**

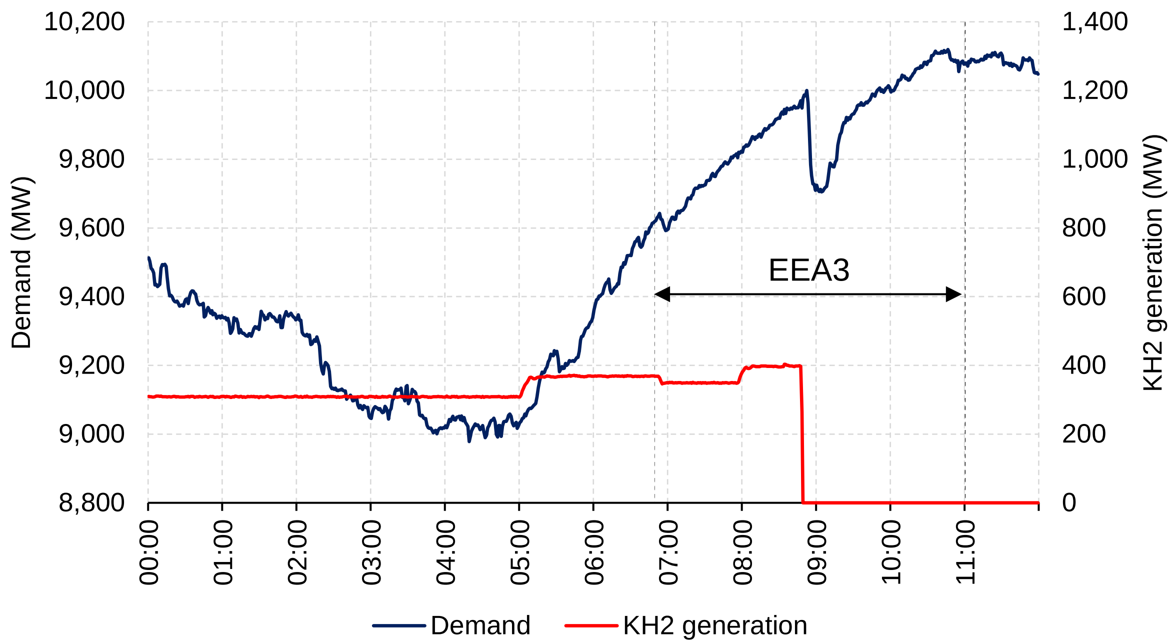
As of April 4 at 17:00, Cascade 1 (CAS1) had 443 MW available for commissioning for HE 09, HE 10, and HE 11 of April 5. However, the unit was forced offline on the evening of April 4 and subsequently the asset's availability for the morning of April 5 was restated to 0 MW.

There were also some assets that had declared default availability as of April 4 at 17:00. For example, Christina Lake (MEG1) was stated as available for its maximum capability of 202 MW until 20:08 on April 4 when the asset's availability for the next day was reduced to 110 MW. Similarly, HR Milner (HRM) and Nabiye (IOR2) were restated down after April 4 at 17:00 to reflect the operating status of these assets at prevailing temperatures (Table 16Table 5).

In addition to the assets in Table 16, the startup of Genesee 2 was delayed. The Genesee 2 asset was initially scheduled to return from its outage in HE 08 of April 5 but at 03:52 on April 5 this start time was pushed back to HE 09. The asset began ramping online at 08:40 and was fully available by around 10:15.

The AESO declared EEA 3 beginning at 06:49 on April 5. At 08:48, the Keephills 2 (395 MW) asset tripped offline and subsequently the AESO began to shed load at 08:53 (Figure 31). The trip at Keephills 2 was the main factor that pushed the AESO from EEA 3 to load shed. The AESO shed load until 09:19 and the EEA 3 event ended at 11:00.

Figure 31: Demand and Keephills 2 generation (morning of April 5)

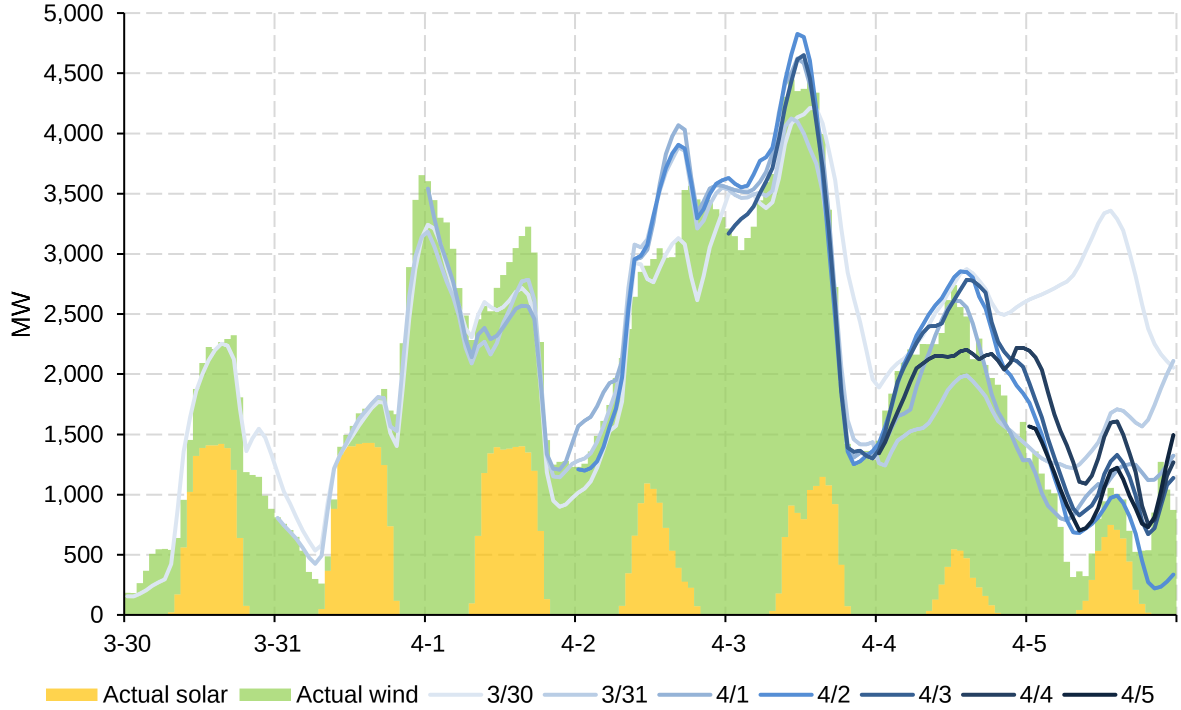


2.4 Wind and solar generation

Wind generation was moderate at approximately 1,300 MW as of midnight on April 5 and declined overnight, reaching approximately 200 MW around the load shed and before solar generation had ramped up. In the days leading up to the load shed, wind and solar forecasts over-estimated generation by approximately 500 to 1,000 MW.

The week-ahead forecast of wind and solar generation on March 30 significantly over-predicted generation for April 5. The remaining forecasts were more accurate but did not anticipate the extent of the wind ramp down in the morning of April 5. Notably, the day-ahead version on April 4 was less accurate than the April 2 version.

Figure 32: Wind and solar forecasts and actual generation (March 30 to April 5, 2024)



The following figures show the 12-hour-ahead forecasts and metered volumes for wind and solar generation on April 5. In these figures, the forecast version time is rolling to always show the outlook 12 hours ahead of real time. Wind and solar generation were both over-forecast for the morning, by approximately 360 MW and 70 MW, respectively, for HE 09.

Figure 33: Forecast and actual wind generation on April 5, 2024

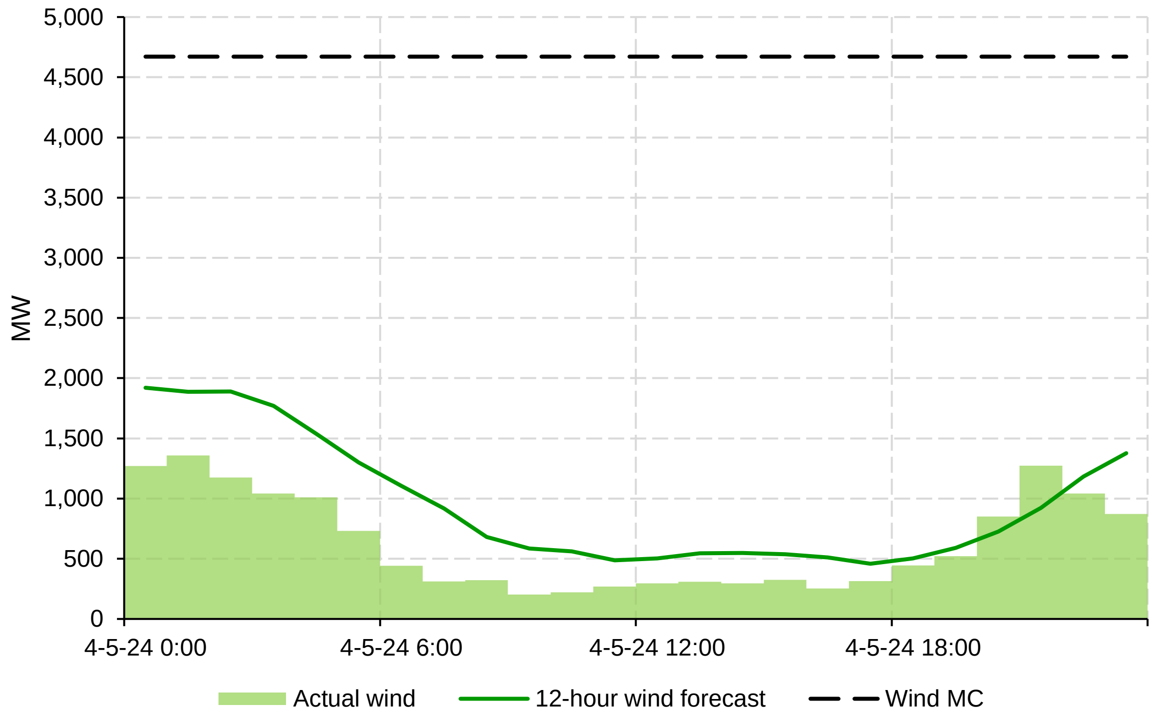


Figure 34: Forecast and actual solar generation on April 5, 2024

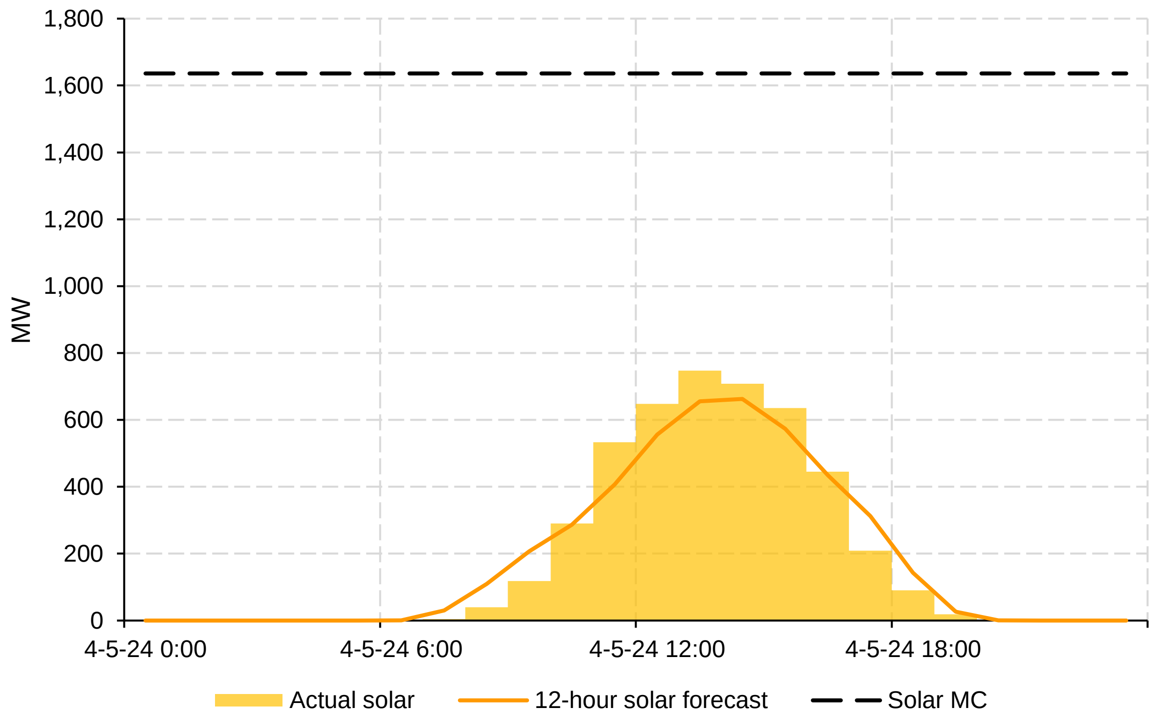
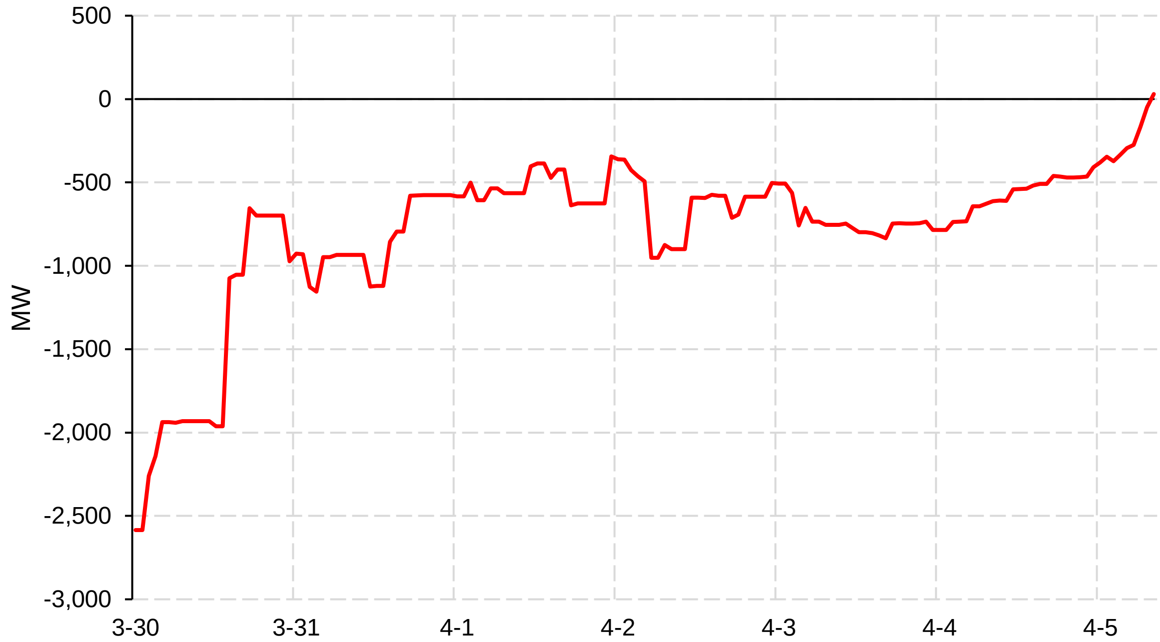


Figure 35 shows that the wind and solar forecast for HE 09 on April 5 over-estimated generation by approximately 500 to 1,000 MW until early that same morning, when the forecast started improving. This contributed to a 400 MW reduction in supply outlook between midnight on April 5 and the load shed around 09:00.

Figure 35: Development of wind and solar forecast error for HE 09 on April 5, 2024



2.5 Adequacy reporting

The Supply Adequacy Report did not anticipate scarcity on April 5, while the Market Supply Cushion Report started predicting low supply cushion for April 5 in the evening of March 31. Neither report was effective in signalling the tight supply conditions that persisted after the load shed into the evening ramp on April 5.

2.5.1 Supply Adequacy Report

Table 17 shows select versions of the Supply Adequacy Report for April 5. For more background on the Supply Adequacy and Market Supply Cushion Reports, see section 1.5.

As of midnight on April 5, there was no indication of reduced supply adequacy. As the early morning progressed, the first signs of shortage started around 03:00, showing some tightness during the morning ramp with adequate supply the rest of the day.

By 04:00, contingency reserve shortages were predicted for HE 08. The forecast remained stable until approximately 06:30 when the code for HE 08 reached 0. The Supply Adequacy Report did not anticipate inadequate supply, although the outlook consistently worsened as conditions unfolded in real time.

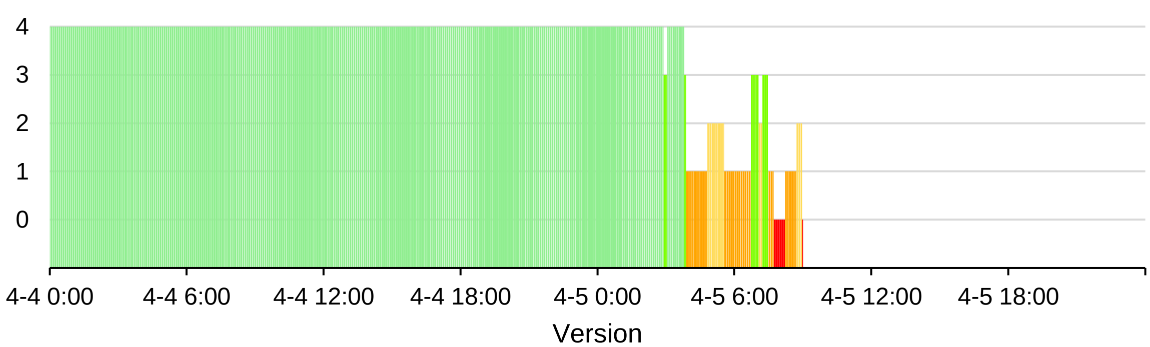
This trend continued through April 5 with forecast versions for the hours in which load was shed predicting conditions would stabilize after the morning. However, tight supply conditions persisted through the day and into the evening ramp.

Table 17: Evolution of Supply Adequacy codes for April 5, 2024

	HE on April 5, 2024																							
Version	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
4/5 00:00	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
4/5 03:00				4	4	4	2	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4
4/5 06:00							2	1	1	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4
4/5 09:00										0	1	3	4	4	4	4	4	4	4	4	4	4	4	4
4/5 12:00													3	4	4	4	4	4	4	4	4	4	4	4
4/5 15:00																3	4	4	4	4	4	4	4	4
4/5 18:00																			2	3	4	4	4	4
Realized[18]	4	4	4	4	4	4	1	0	0	0	1	2	3	2	3	3	2	1	2	3	4	4	4	4

Figure 36 shows that adequate supply was expected for HE 09 until 06:00. The forecast outlook even improved leading up to real time before quickly falling to code 0. Near the end of HE 09 – but before the load shed began at 08:53 – the outlook started improving and reached a code 2, indicating full contingency reserve volumes and up to 200 MW of supply available.

Figure 36: Evolution of Supply Adequacy code for HE 09 April 5, 2024



[18] Supply adequacy forecasts for a given hour continue to be updated in real time through to the end of that hour. Realized values indicate the minimum value posted in real time while the hour was unfolding.

2.5.2 Market Supply Cushion Report

Table 18 shows a selection of Market Supply Cushion Report versions leading up to the load shed and evening scarcity on April 5. As described in section 1.5.2, the AESO does not retain the actual market supply cushion data that it publishes, so the MSA replicated the codes using the calculation described in the report documentation.

Like the January event, on April 5 the Market Supply Cushion Report more accurately predicted the time and severity of adequacy issues compared to the Supply Adequacy Report. However, like the Supply Adequacy Report, it did not predict the sustained supply tightness through the afternoon and early evening, with the 12:00 version showing a code of 3 from HE 14 onward.

Table 18: Evolution of Market Supply Cushion codes for April 5, 2024

	HE on April 5, 2024																							
Version	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
4/5 0:00	3	3	3	3	3	3	1	1	1	1	1	1	2	2	2	2	1	2	2	2	2	3	3	3
4/5 3:00				2	2	2	0	0	2	1	1	1	2	2	2	2	1	2	2	2	2	3	3	3
4/5 6:00							1	0	0	2	2	1	2	2	2	2	1	1	1	1	1	3	3	3
4/5 9:00										0	0	2	3	3	3	2	2	2	2	2	2	3	3	3
4/5 12:00													2	3	3	3	3	3	3	3	3	3	3	3
4/5 15:00																2	2	2	3	3	3	3	3	3
4/5 18:00																			1	2	2	3	3	3
Realized[19]	3	3	2	2	2	3	0	0	0	0	0	1	1	1	2	2	1	0	1	1	3	3	3	3

As shown in Figure 37, the code for HE 09 dropped to code 0 the evening of March 31 and remained low through the day on April 1. However, through April 2 and 3, the code was mostly at 3 (the highest level). The code fluctuated significantly through the day on April 4 and, like the Supply Adequacy Report, fell over the morning of April 5 leading up to the load shed event.

[19] Market supply cushion forecasts for a given hour continue to be updated in real time through to the end of that hour. Realized values indicate the minimum value posted in real time while the hour was unfolding.

Figure 37: Evolution of Market Supply Cushion code for HE 09 April 5, 2024

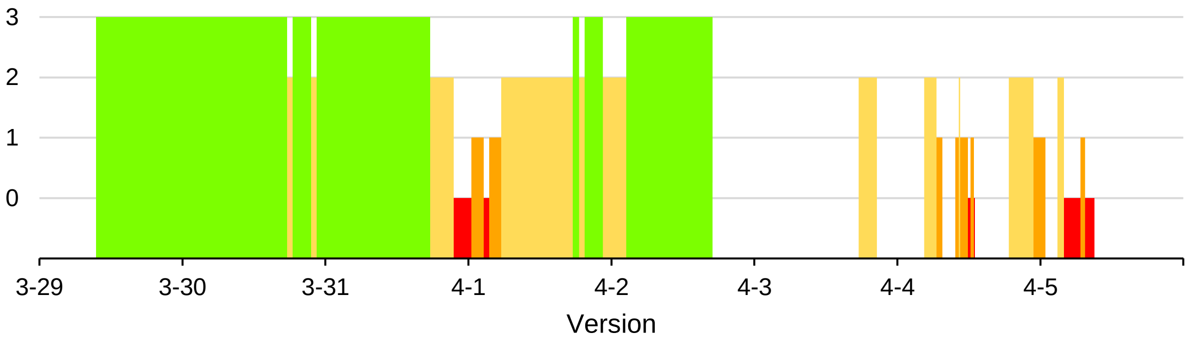
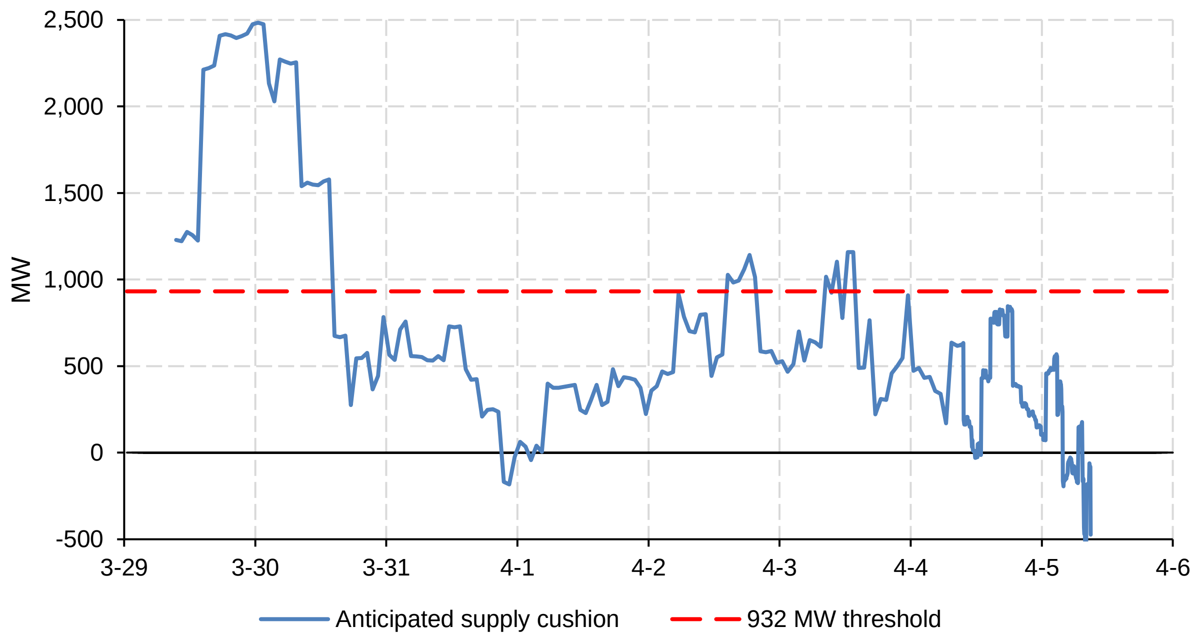


Figure 38 shows the forecast supply cushion for HE 09 compared to the 932 MW threshold used to issue unit commitment directives under the *Supply Cushion Regulation*. The anticipated supply cushion was consistently below the threshold as of midday on April 3, including all of April 4. While the anticipated supply cushion calculation has been updated, this nonetheless suggests that Battle River 5, which was commercially offline during the event, would have received a directive if the *Supply Cushion Regulation* had been in effect. Had such a directive been issued and Battle River 5 successfully responded, load shed would not have been required.

Figure 38: Evolution of Market Supply Cushion for HE 09 April 5, 2024



2.6 Operating reserves

The AESO made extensive use of contingency reserves to provide energy in order to maintain the balance of supply and demand during the EEA event on April 5.

Contingency reserves were directed on for energy for 201 minutes from 6:53 to 10:13 on April 5. Supplemental reserves from generation and load were directed on for the entire duration of this event, while spinning reserve providers received directives from 7:30 to 9:57. Table 19 highlights maximum and average directed volumes per product in addition to the duration of time a product's available MW were fully directed on during this event. Supplemental reserves were exhausted for the majority of this period. Load-based supplemental reserve was fully directed on for 95% of the event, with its generation-based counterpart being fully directed on for 78% of the event.

Figure 39, Figure 40, Figure 40, and Figure 41 illustrate contingency reserve directives on a minute-by-minute basis throughout the course of the April 5 event. At 8:48 KH2 tripped offline, resulting in a 40 MW decrease in spinning reserve volumes. Notably, beginning at 9:12 there was a 7-minute period in which 8 MW of spinning reserves were unused while the AESO shed load.

Table 19: Contingency reserve directives by product (April 5, 2024)

Contingency Reserve Product	Average Directed Volume (MW)	Maximum Directed Volume (MW)	Duration of Time with 100% Dispatched Volume Directed (Minutes)
SR	149	240	23
SUPG	144	161	156
SUPL	80	82	191

Figure 39: Spinning reserve directives (April 5, 2024)

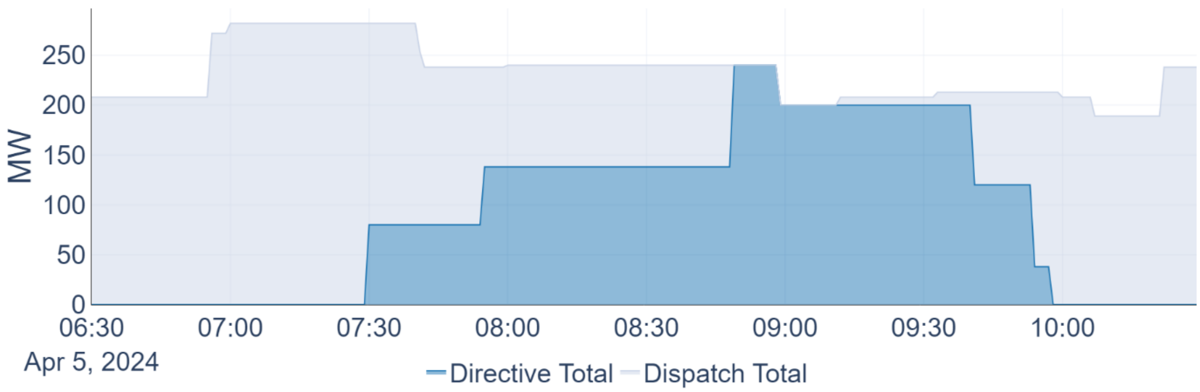


Figure 40: Supplemental generation directives (April 5, 2024)

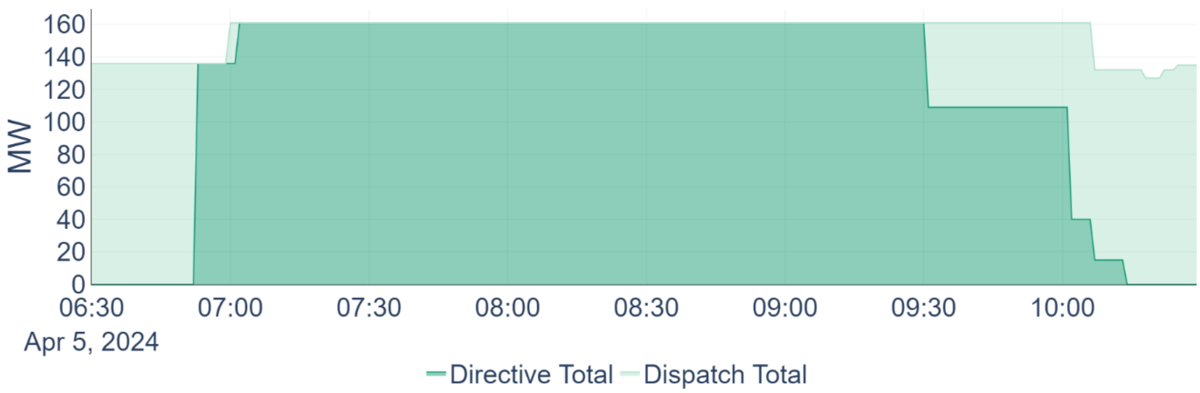
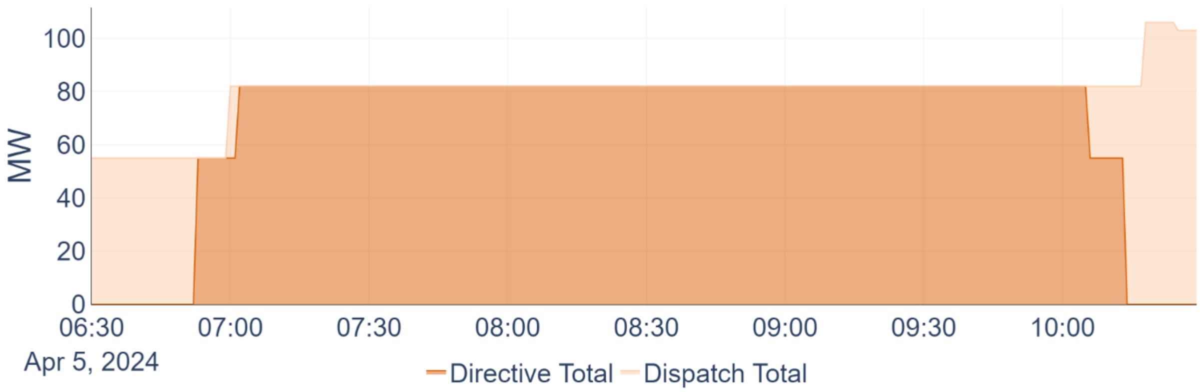


Figure 41: Supplemental load directives (April 5, 2024)



2.7 Natural gas market

The April 5 event was not driven by abnormal weather patterns so there was little impact on the natural gas market. The supply of natural gas to thermal generators was not an issue for the April 5 event.

Unlike the January event, the load shed event on April 5 was not driven by extreme weather conditions. As discussed above, average temperatures on April 5 ranged from 0 to -1°C. Therefore, the natural gas market was not materially affected by this event. Figure 42 illustrates natural gas prices over March and April. On April 5 natural gas prices settled at $1.59/GJ, which continued the slight downward trend seen in early April.

Figure 42: Same day (2A) natural gas prices at AB-NIT (March 1 to April 30)

2.8 Interties and other jurisdictions

Prices in Alberta were higher than in nearby jurisdictions on April 5. As a result, import capability was fully used over the EEA 3 event. Additionally, the AESO increased BC/MATL import capability beyond limits determined by LSS/FFR volumes. Following the Keephills 2 trip, the AESO requested Northwest Power Pool Reserve Sharing imports.

Figure 43 shows that net imports exceeded the AESO's forecast from 12 hours ahead throughout the day on April 5. During the load shed around 09:00, net imports were approximately 353 MW higher than predicted, due in part to reserve-sharing imports discussed below.

Figure 43: Net imports vs. forecast on April 5, 2024

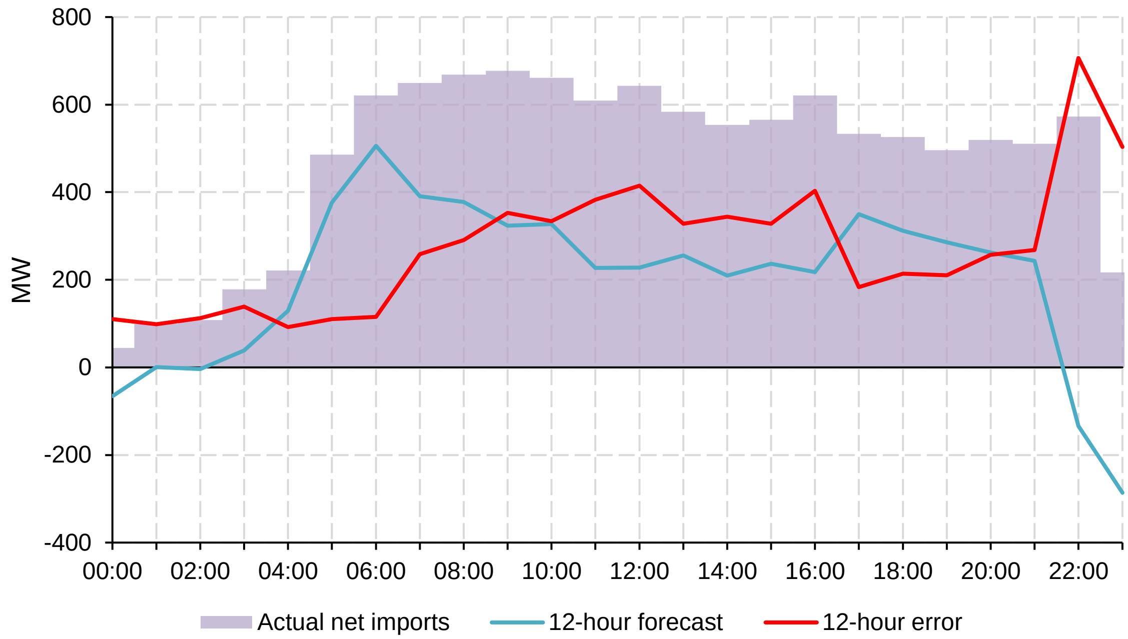


Figure 44 shows that forecast versions starting two days ahead significantly underestimated net imports in HE 09 on April 5. The forecast started to slowly improve and converged significantly starting 6 hours ahead.

Figure 44: Net import forecast for HE 09 on April 5, 2024

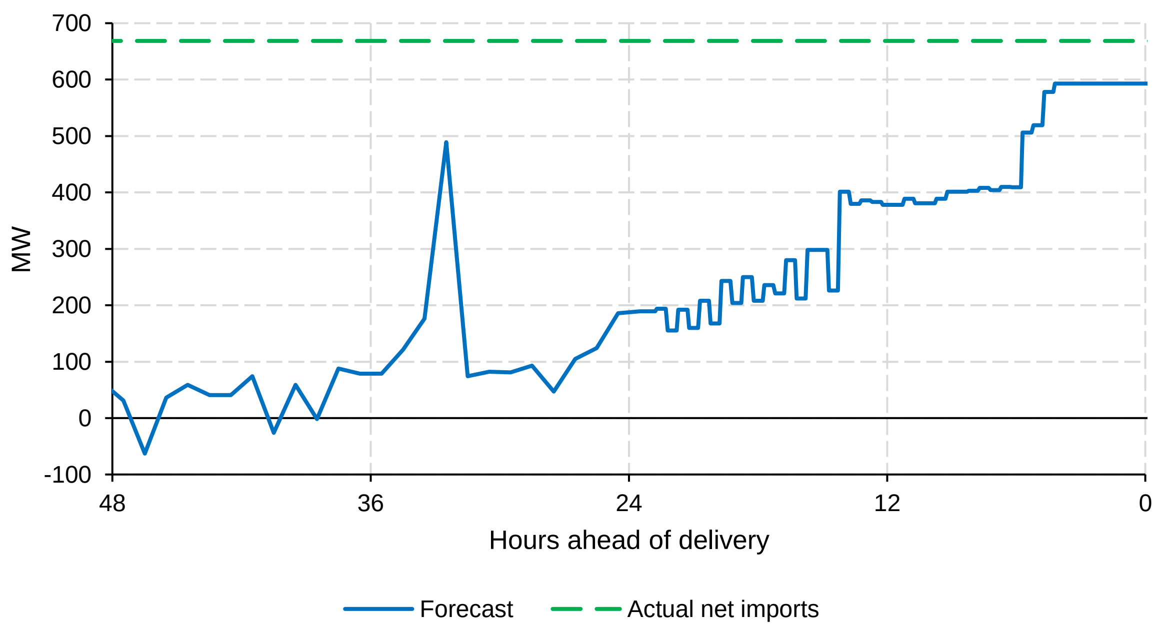


Figure 45 shows hourly power prices in Alberta, Mid-C, and California (SP-15) over April 1 to 6. In contrast to these other jurisdictions, Alberta experienced periods of high prices over this period, with multiple hours at the price cap from April 3 through April 5. Over April 5, the daily price differential between Alberta and Mid-C averaged $406/MWh, resulting in import capability that was largely fully used over the course of the day.

Figure 45: Hourly power prices in Alberta, Mid-C and SP-15 California (April 1 to 6, 2024)

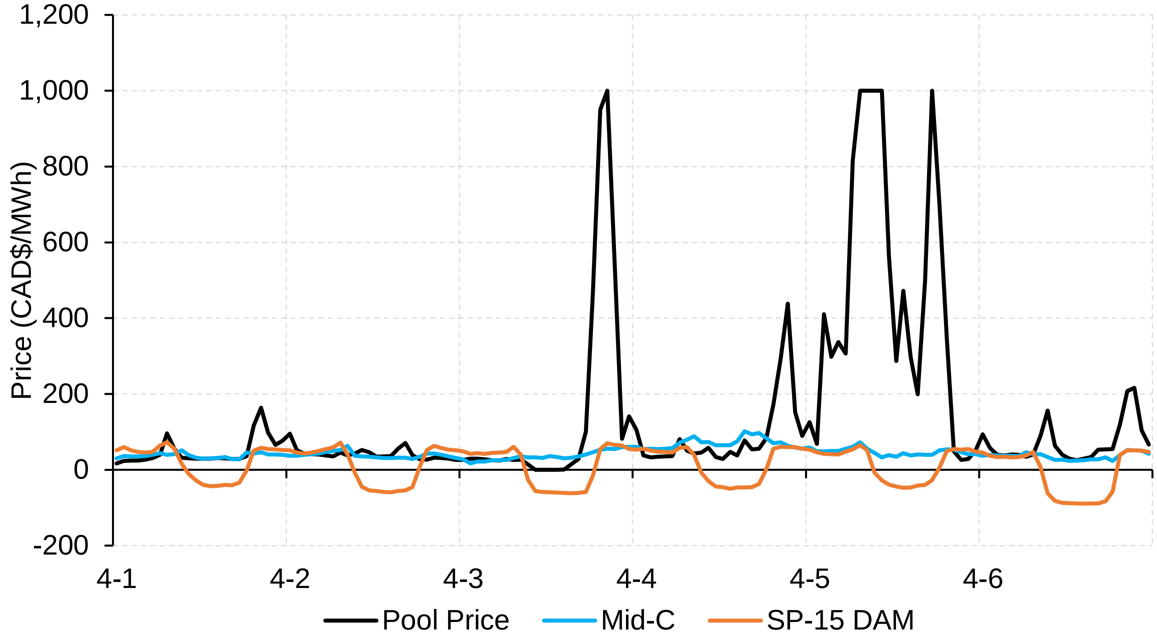


Figure 46 shows the connection between combined LSS/FFR volumes offered at T-85 and BC/MATL import ATC. Market participants offered little LSS volume on April 5. As the MSA has previously reported, there is an inverse relationship between LSS availability and pool price, as the loads that provide LSS are generally price responsive and voluntarily curtail when prices are high.[20]

For that reason, BC/MATL import ATC was lower over the day compared to earlier in the week. For the duration of the EEA 3 event, 44 MW of LSS and 77 MW of FFR were offered and armed by the AESO. The connection between BC/MATL import ATC and offered LSS/FFR volumes deviated during the EEA 3 event as the AESO permitted more imports than normal. This reflects the risk trade-off between increasing intertie capability and shedding load. Increasing BC/MATL imports beyond capability limits determined by available LSS/FFR resources increases supply but also increases the potential impact to system reliability in the event of an unexpected trip on the intertie and sudden loss of imports.

[20] See MSA Quarterly report for Q2 2018 for example.

Figure 46: LSS/FFR volume, Pool Price, and BC/MATL import ATC (April 1 to 6, 2024)

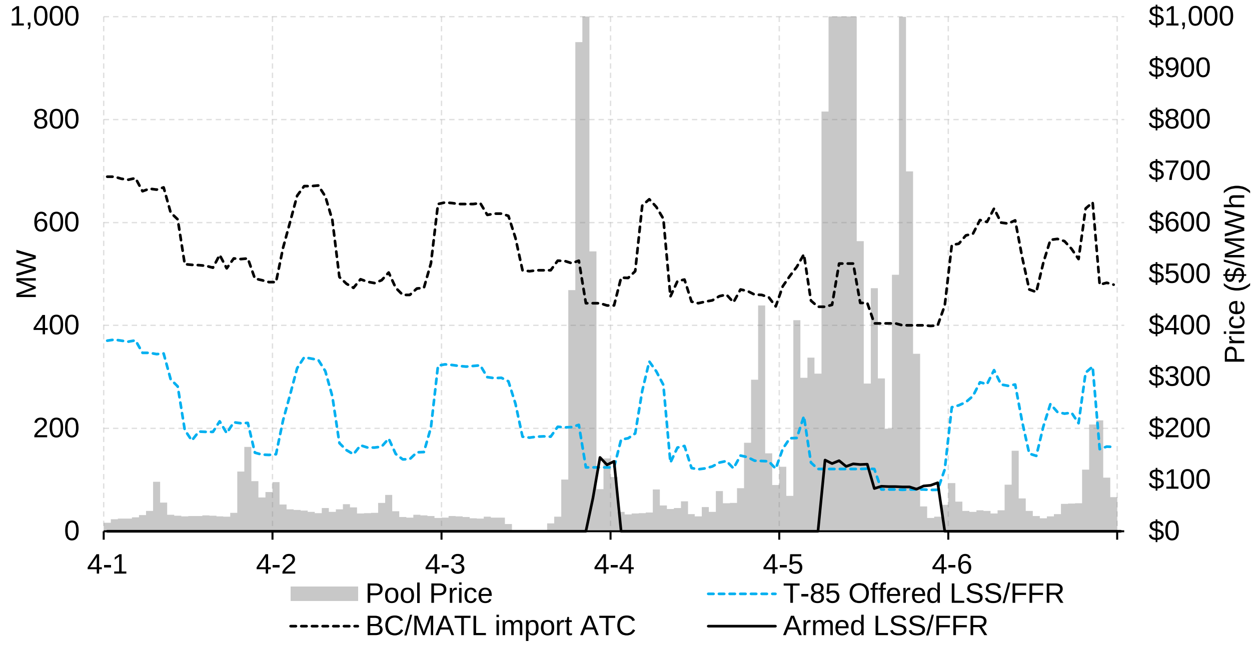


Figure 47 shows prices, hourly intertie volumes, and joint capability for BC/MATL. Over April 5, BC/MATL import capability averaged 447 MW and export capability averaged 935 MW except for periods associated with the EEA 3, when exports were prohibited. Over the course of the day flows on MATL averaged 78 MW of net imports and flows on BC averaged 275 MW of imports.

Figure 48 shows prices, hourly intertie volumes, and capability of the SK intertie. Over April 5, SK import capability averaged 153 MW and export capability averaged 153 MW, except for the periods associated with the EEA 3 event, when exports were prohibited. Over the course of the day, flows on SK averaged 123 MW of net imports. No exports were scheduled on BC, SK, or MATL on April 5.

At the time that the April 5 EEA 3 event began (06:49), 270 MW of net imports were scheduled on BC and 166 MW of net imports were scheduled on MATL, with the 436 MW BC/MATL import capability being fully used. Additionally, 150 MW of net imports were scheduled on the SK intertie, out of the 153 MW SK import ATC. From HE 08 through HE 23, 153 MW was scheduled on the SK intertie, meaning that it was fully used over this period (Figure 48).

At 07:27, BC import ATC was increased from 344 MW to 400 MW and e-Tags applicable to HE 08 were reloaded[21] to 400 MW intra-hour. Additionally, MATL import ATC was increased from 96 MW to 120 MW; however, the associated e-Tags were not reloaded. BC/MATL import capability remained at 520 MW and was fully used through HE 11 with 400 MW of imports through the BC intertie and 120 MW of imports through MATL. Following the trip of KH2 at 08:48, the AESO made

[21] Reversing at least a portion of a previously curtailed e-tag.

a request for 95 MW of North West Power Pool reserve sharing imports at 08:52 that lasted until 09:27 (Figure 47).[22]

Figure 47: Hourly import (+ve) and export (-ve) volumes on BC/MATL, and price differential between Alberta and Mid-C (April 1 to 6)

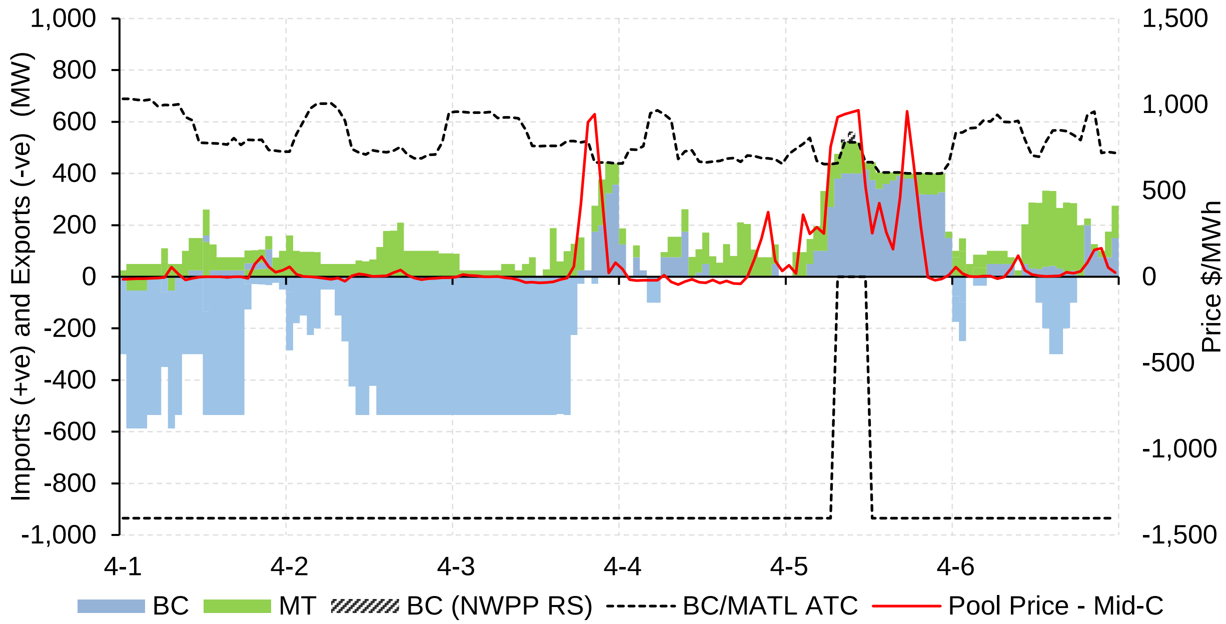
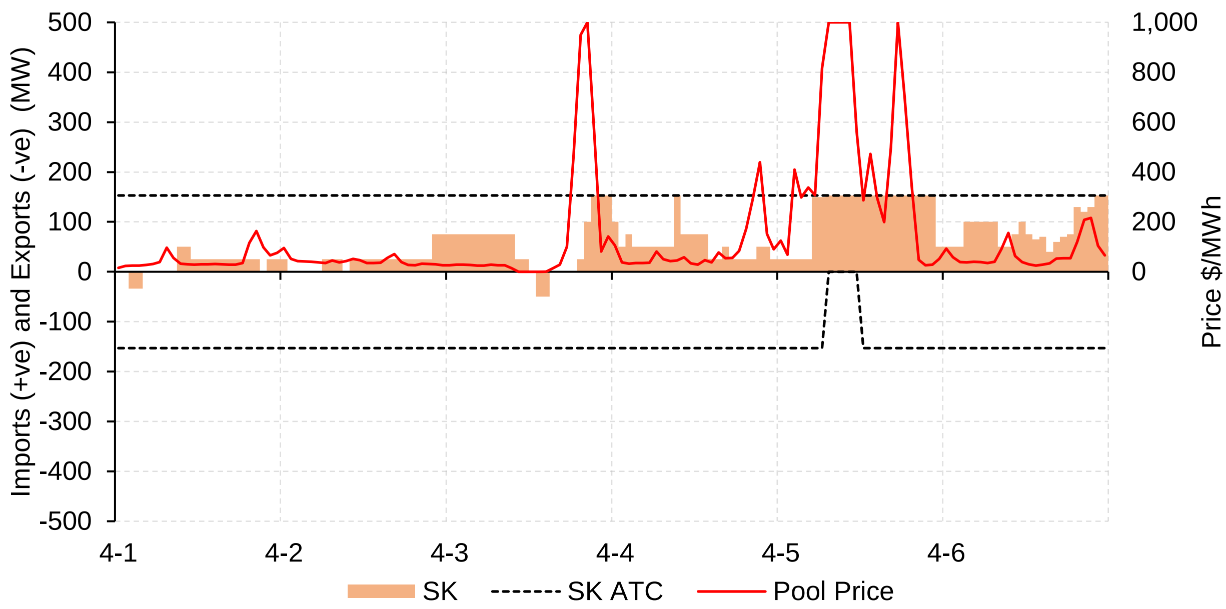


Figure 48: Hourly import (+ve) and export (-ve) volumes on SK, and pool price (April 1 to 6*)*



[22] AESO system controller Shortfall Management April 5, 2024 document