MARKET SURVEILLANCE ADMINISTRATOR

Quarterly Report for Q3 2020

November 10, 2020

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

www.albertamsa.ca

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THE QUARTER AT A GLANCE

- The overall price level in the Alberta market indicates the power pool was competitive in Q3 2020.

- The average pool price in the quarter was $43.83/MWh, a 6% decline compared to Q3 2019 but a 47% increase compared to Q2 2020. The average pool price was increased by a small number of high-priced hours in July and August when high temperatures increased demand and supply was restricted by thermal outages and lower wind generation.

- The pool price was below $50/MWh in 94% of hours in Q3 as the market experienced reduced demand, notably high import levels in July and August, and increased wind generation. The market continued to experience supply surplus events, with the market clearing at $0/MWh during the lighter load hours on several days.

- The marked reduction in Alberta's total electricity demand continued. In July demand was 5.4% lower than last year, and in August demand was 5.0% lower than last year despite materially warmer temperatures in August 2020. In September demand levels recovered somewhat and the year-over-year reduction was 3.4%.

- The price of the Calendar 2021 (CAL21) contract was relatively stable at around $51.00/MWh during Q3 2020 but the price rose in late September and in October and it was valued at $55.50/MWh as of November 2.

- The BC/MATL intertie was initially scheduled to be offline for the second half of September but on August 20 the transmission work was rescheduled to the second half of October. As a result, the forward price for September, which had been trading at around $60.50/MWh, fell to $47.00/MWh and the October forward price rose from $46.25/MWh to $55.00/MWh.

- Trading activity in the forward market has been in decline for a number of years and this pattern continued in Q3 2020. The low level of trading for annual contracts, such as CAL21, is most notable. This report includes a summary of discussions the MSA has had with some market participants regarding reduced forward trading volumes.

- The cost of operating reserves was 8% lower than Q3 2019. The primary driver of the costs of active reserves is pool price, which on average, was down 6% year-over-year.

- From July 1 to September 30, 2020, the MSA closed 91 ISO rules compliance matters; 14 matters were addressed with notices of specified penalty. From July 1 to September 30, 2020, the MSA closed 41 Alberta Reliability Standards Operations and Planning compliance matters; four matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Summary

The overall price level in the Alberta market indicates the power pool was competitive in Q3 2020. Market summary statistics for the quarter are reported in Table 1.

Table 1: Market summary

		2020	2019	Change
Pool Price (Avg $/MWh)	Jul	54.14	40.99	*32%*
	Aug	41.05	45.40	*-10%*
	Sep	36.05	54.45	*-34%*
	Q3	**43.83**	**46.87**	***-6%***
Demand (AIL) (Avg MWh)	Jul	8,974	9,486	*-5.4%*
	Aug	8,971	9,443	*-5.0%*
	Sep	8,845	9,159	*-3.4%*
	Q3	**8,931**	**9,365**	***-4.6%***
Gas Price AB-NIT (2A) (Avg $/GJ)	Jul	1.89	1.34	*42%*
	Aug	2.33	0.71	*229%*
	Sep	2.20	0.51	*334%*
	Q3	**2.14**	**0.85**	***151%***
Wind (Avg MWh)	Jul	506	323	*57%*
	Aug	513	286	*79%*
	Sep	592	438	*35%*
	Q3	**536**	**348**	***54%***
Net Exports (+) Net Imports (–) (Avg MWh)	Jul	-766	-102	*655%*
	Aug	-772	-174	*343%*
	Sep	-120	-67	*78%*
	Q3	**-558**	**-115**	***385%***
Supply Cushion (Avg MW)	Jul	2,130	1,923	*11%*
	Aug	2,483	1,830	*36%*
	Sep	1,951	1,694	*15%*
	Q3	**2,190**	**1,817**	***21%***

The average pool price in the quarter was $43.83/MWh, a 6% decline compared to Q3 2019 but a 47% increase compared to Q2 2020. Pool prices were below $50/MWh for 94% of the hours in Q3 2020, and below $30/MWh for 39% of hours.

The reduction in average pool price year-over-year was primarily driven by increased imports and wind generation coupled with lower demand. As a result, the average supply cushion was 21% higher year-over-year, indicating more supply competing to serve demand.

Offsetting these factors was a material increase in natural gas prices year-over-year, although natural gas units only set the System Marginal Price (SMP) 36% of the time in Q3 2020, compared to coal which set the SMP 61% of the time.

Total demand for electricity in Alberta (Alberta Internal Load or AIL) continued to be below the total demand observed last year. In August 2020 average AIL was 5.0% lower than last year despite materially higher temperatures in 2020, which would be expected to increase cooling demand.

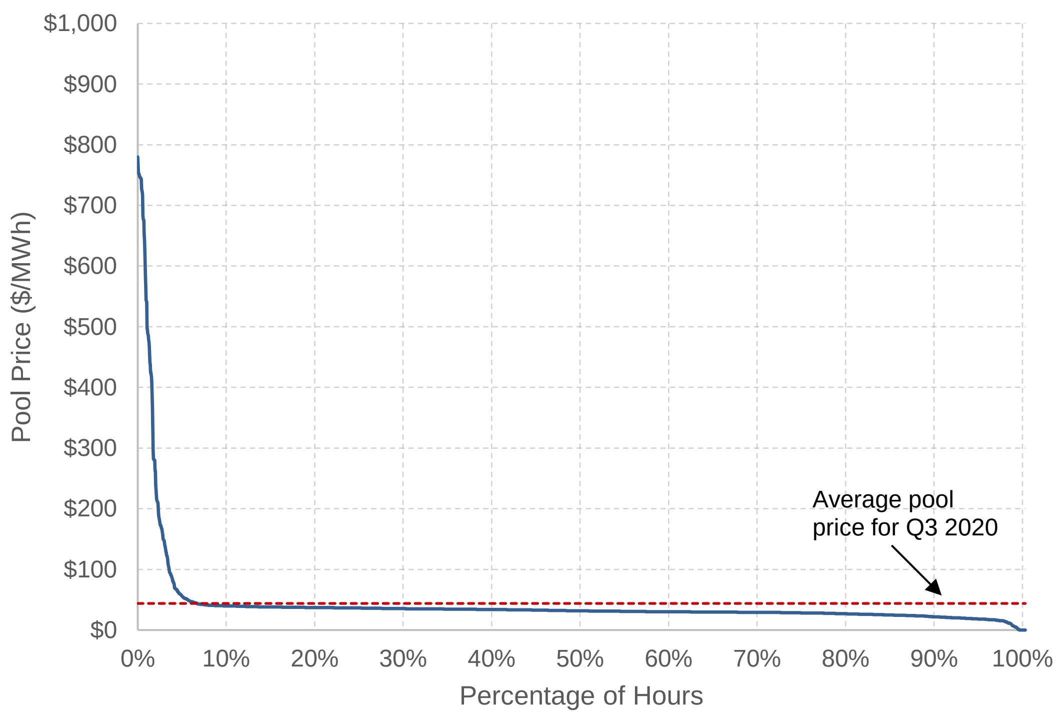
The year-over-year demand declines observed for July and August were driven in part by a fall in consumption by large industrial consumers, such as oil sands operations, which have built their own generation on-site. The Alberta Energy Regulator (AER) reported a 13% year-over-year decline in Alberta's total oil production for July and a 16% decline for August, as West Texas Intermediate (WTI) oil prices hovered around US$40/bbl for much of the quarter, with Western Canadian Select (WCS) oil priced around US$30/bbl in Q3 2020 compared with US$43/bbl in Q3

2019.[1] Alberta's reduced electricity demand in Q3 continued to reflect the economic implications of the COVID-19 pandemic.

1.2 Market outcomes

The solid blue line in Figure 1 illustrates the distribution of pool prices in Q3 2020. In particular, the line depicts the percentage of hours that were above the corresponding pool price. In 7% of hours in the quarter the pool price settled above the average of $43.83/MWh (shown by the dashed red line). The average pool price in the top 7% of hours was $231.58/MWh and it accounted for $15.42/MWh (or 35%) of the average pool price for the quarter, indicating that a small number of relatively high-priced hours materially contributed to determining the average pool price for the quarter. This concentration of revenue provided a strong incentive for generation to be available and producing during the hours when the pool price was relatively high. Similarly, price-responsive loads had an incentive to reduce consumption during these hours, if possible, in order to lower overall electricity costs.

Figure 1: Pool price duration curve for Q3 2020

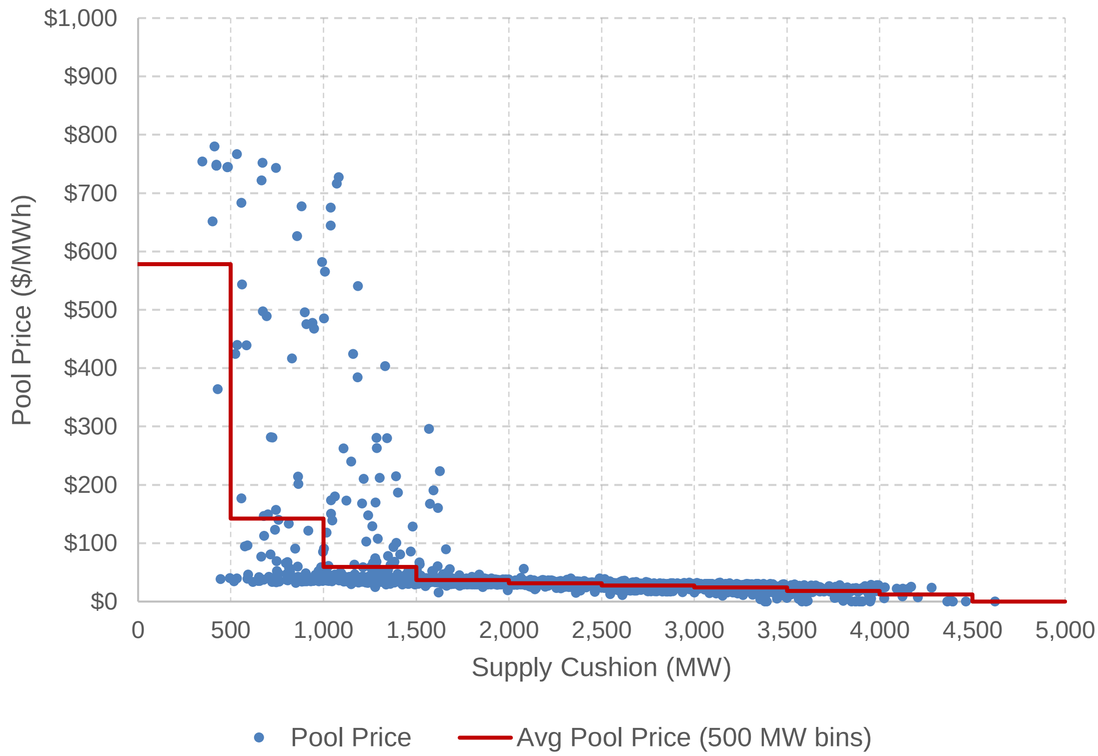


[1] AER ST3 report Oil Supply & Disposition, Total Production (Row 28)

Canada Energy Regulator (CER) Commodity Prices and Trade Updates

Pool prices during the quarter ranged from the price floor of $0/MWh up to $780/MWh. Figure 2 illustrates the relationship between hourly supply cushion and pool price in Q3 2020.[2] As expected, pool prices tend to be lower when the supply cushion is high. A pool price of $0/MWh reflects a supply surplus situation. This normally happens during off-peak hours when demand is low and when there is a large amount of supply from imports and/or wind.

Figure 2: Scatterplot of supply cushion and pool price (Q3 2020)



Low supply cushion values reflect tighter market conditions, such as high temperatures driving up cooling demand in combination with derates of thermal generators restricting supply. A low supply cushion hour with a high pool price may be reflective of higher generator offer prices, which may be increased in recognition that there is less supply to serve prevailing demand.

However, as shown in Figure 2, not all hours with a low supply cushion result in a high pool price. A low supply cushion hour with a relatively low pool price often reflects less generation capacity offered at a higher price, which may, among other reasons, be caused by the inability of suppliers to forecast the tight market conditions or reflect the portfolio position of one or more large suppliers. For example, a supplier with a large amount of fixed-price sales and a large generating

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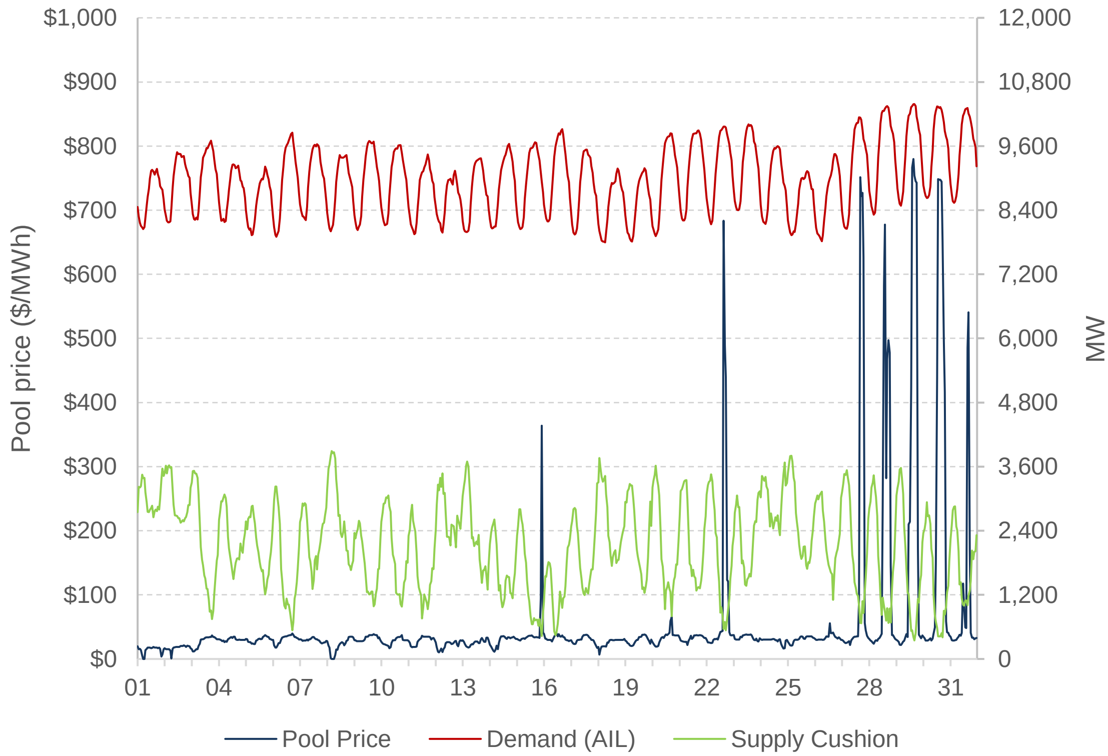
[2] The supply cushion value is a summary measure of supply-demand conditions in the energy market. In particular, the supply cushion is a calculation showing how much available generation capacity the market has above that which is required to meet prevailing demand.

unit on outage may have a limited commercial incentive to offer its remaining capacity at prices above its short-run marginal cost.

1.2.1 July 2020

The average pool price in July 2020 was $54.14/MWh, the highest monthly price in the quarter. The average price was driven largely by some high-priced hours during the last week of the month. Figure 3 shows pool prices, supply cushion, and total demand over the month. As shown in Figure 3, pool prices were relatively low for the first half of the month with low demand, high imports, and 650 MWh of wind generation on average. Over the course of July, AIL was down 5.4% on average compared to last year as the economic implications of COVID-19 continued. On the supply side, imports were 766 MWh on average, utilizing 93% of the total available import capacity.

Figure 3: Demand, supply cushion, and pool price (July 2020)



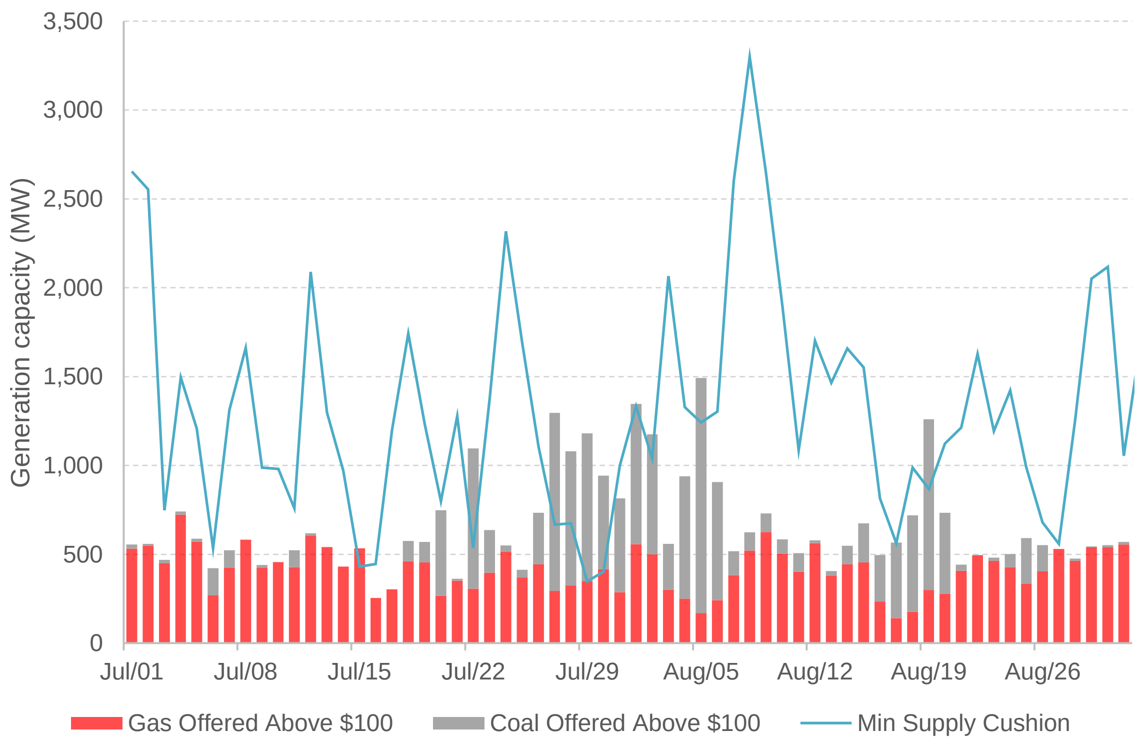
The elevated levels of average wind generation observed in Q2 continued into Q3. Table 2 below shows average wind generation and capacity factor by month for Q3 2019 and 2020. As shown, year-over-year, the market observed higher levels of wind generation on average, driven by a 336 MW increase in new wind capacity and by a better capacity factor in Q3 2020.

Table 2: Wind generation and capacity factor (Q3 2020 and 2019)

Month	2020		2019	
	Avg generation (MWh)	Capacity factor	Avg generation (MWh)	Capacity factor
July	506	28%	323	22%
August	513	29%	286	20%
September	592	33%	438	27%

Despite the monthly average of 506 MWh, wind generation was low during some high-price hours in July. For example, in HE16 of July 22 average wind generation was 175 MWh as the supply cushion dropped to 560 MW as a result of two large coal plants being offline and the BC/MATL intertie being derated to 550 MW of import capacity due to weather concerns. In response to the tighter market conditions some suppliers increased the offer prices of their coal generators (see Figure 4) and the pool price settled at $684/MWh.

Figure 4: Minimum daily supply cushion and associated high-price thermal offers (July and August 2020)

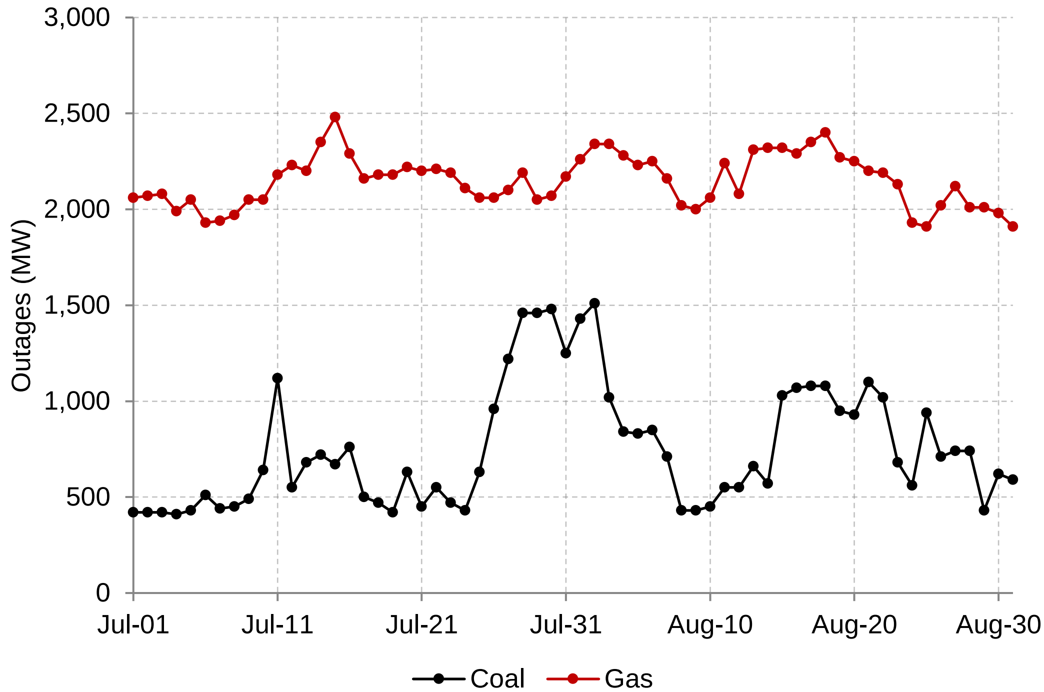


The supply cushion was also relatively low during some peak hours of July 27 to 31. Demand on these days was elevated due to the high temperatures in Alberta, with maximum temperatures reaching 29°C on July 27 and 30°C on July 28.[3] On the supply side, wind generation was relatively

[3] Temperatures used are the average of hourly temperatures in Calgary, Edmonton, and Fort McMurray

low, averaging 300 MWh during the peak hours of July 27 to 31 and, more significantly, two large coal plants were on outage during this period (see Figure 5). As shown by Figure 4, some suppliers increased their offer prices during this week in response to the tighter market conditions.

Figure 5: Daily average thermal generation outages (July and August 2020)[4]

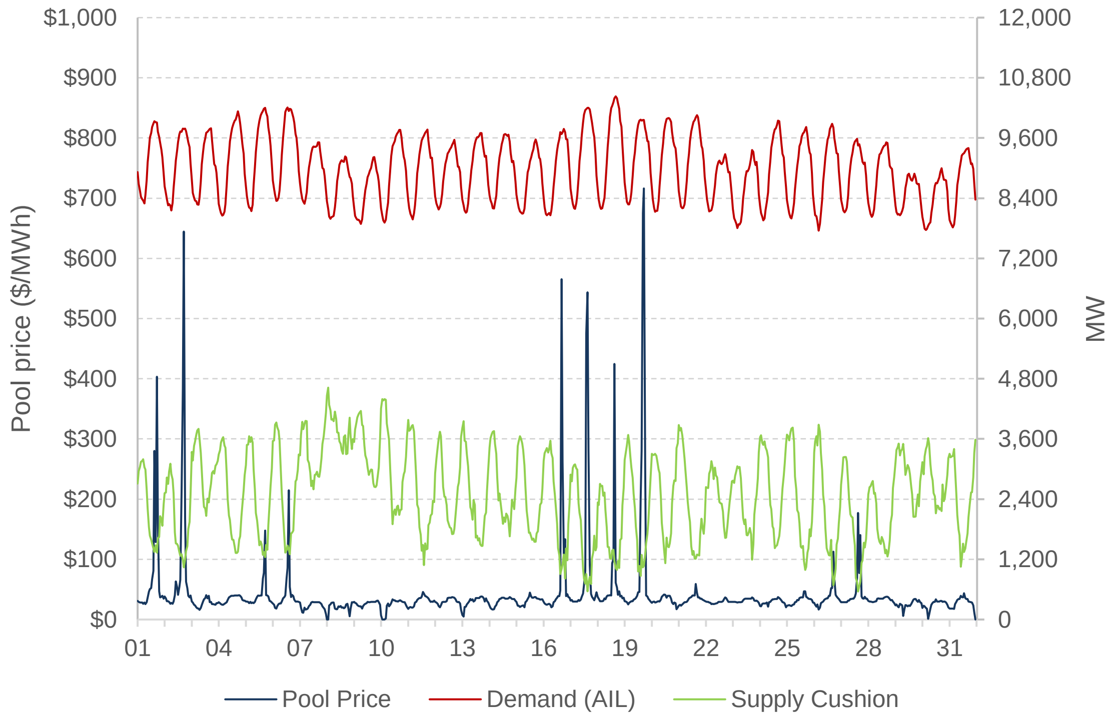


1.2.2 August 2020

Some of the market factors observed at the end of July carried over into the weekend of August 1 and 2, notably coal generator outages and supplier offer behaviour, and despite weekend load levels some higher pool prices were observed (see Figure 6).

[4] Sundance 3, which was retired in late July, is not included in the coal outage figures.

Figure 6: Demand, supply cushion, and pool price (August 2020)



Between August 3 and 15 pool price volatility was lower as supply cushion increased as a result of coal plants returning to the market. Temperatures did increase again on August 5 and 6 but pool prices did not get as high with more coal capacity available. In early-to-mid August the market continued to receive an influx of imports despite pool prices being relatively low on many days. In a few off-peak hours pool prices cleared at $0/MWh reflecting that supply surplus conditions were in effect for the whole hour.

Pool price volatility increased again from August 16-19 as supply cushion fell (see Figure 6). The higher pool prices were the result of warmer temperatures for August 16-18, increased thermal outages, lower wind generation in some cases, and generator offer behaviour. In addition, net imports into Alberta were reduced during these high-priced hours as some power was wheeled from BC into Alberta, out through Montana and then to California. Figure 8 illustrates the day-ahead and real-time Locational Marginal Prices (LMPs) at SP15 across August 12-24.[5] As shown, LMPs at SP15 were above CAD$1,000/MWh in some hours during mid-August when California experienced a significant and extended heat wave.[6]

[5] SP15 is a major electricity hub in Southern California

[6] CNBC: Sweltering heat is shattering records, triggering power outages across California – August 15, 2020

Figure 7: Pool price, import ATC, and net imports (August 12-24)

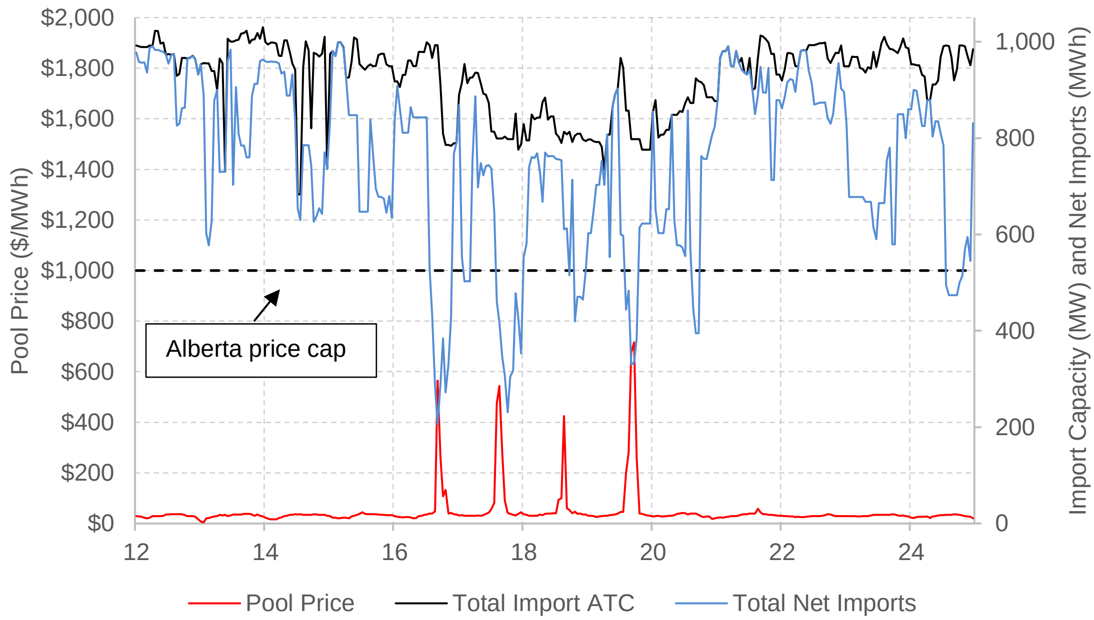
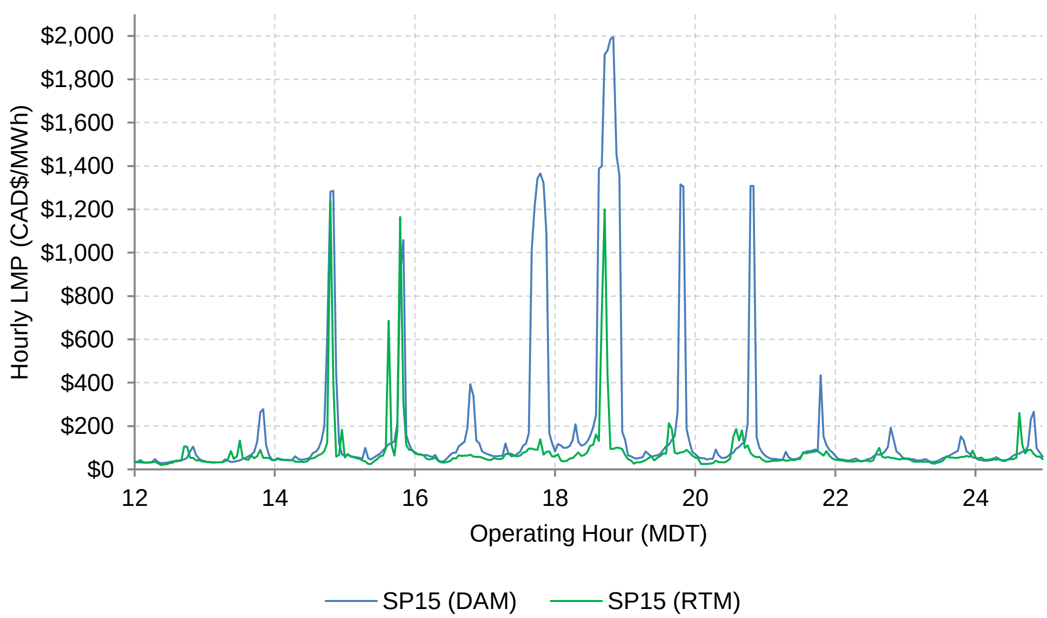


Figure 8: Day-ahead and real-time market prices at SP15 in California (August 12-24)[7]



[7] DAM: CAISO OASIS > Prices > Locational Marginal Prices > Market = DAM, Node = TH_SP15_GEN-APND

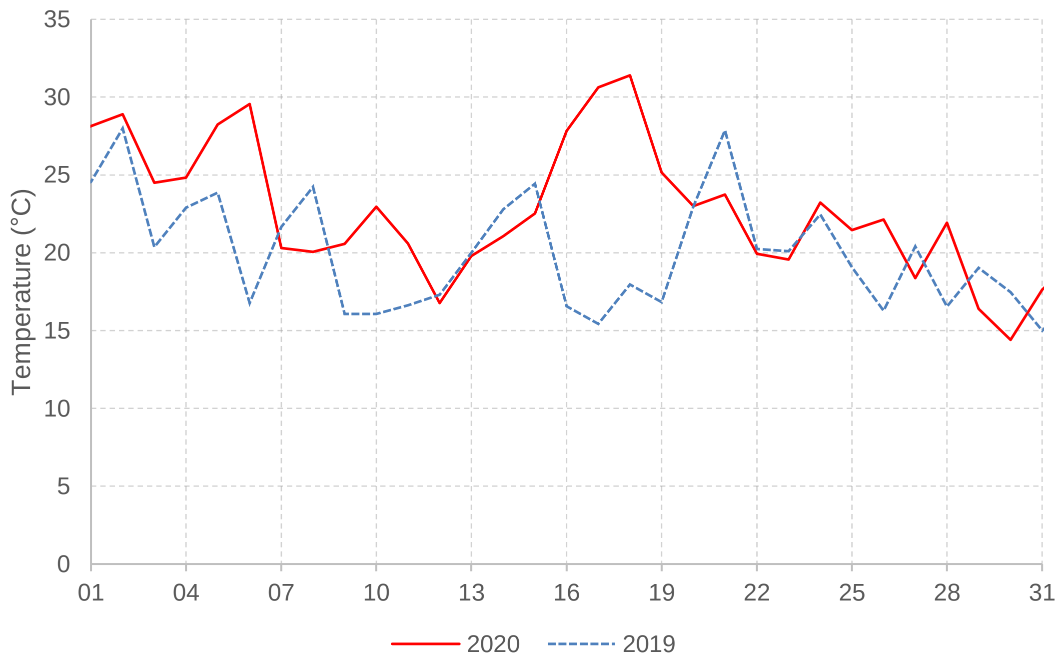
RTM: CAISO OASIS > Prices > Interval Locational Marginal Prices > Node = TH_SP15_GEN-APND

Prices are converted from USD to CAD using the Bank of Canada's daily exchange rate

Alberta's total electricity demand in August 2020 was 5.0% below that observed in August 2019, despite the fact that the average temperature was 2.1°C warmer in 2020. Figure 9 below shows that the higher average temperature was largely driven by the hot temperatures experienced in mid-August 2020 and, to a lesser extent, on August 5-6, 2020. These higher temperatures increased the demand for power, so had Alberta experienced the moderate temperatures of August 2019 this year demand would likely have been even lower. The AESO's weather-normalized demand model estimates observed AIL was around 8% lower than normalized AIL for August 2020. Normalized AIL uses historical demand and weather data to estimate a normalized level of AIL demand given prevailing temperatures.

Pool prices in the August 20-31 period were relatively low as temperatures decreased, thermal availability improved and there was a high volume of net imports; 715 MWh on average.

Figure 9: Daily maximum temperatures for August (2020 and 2019)[8]



1.2.3 September 2020

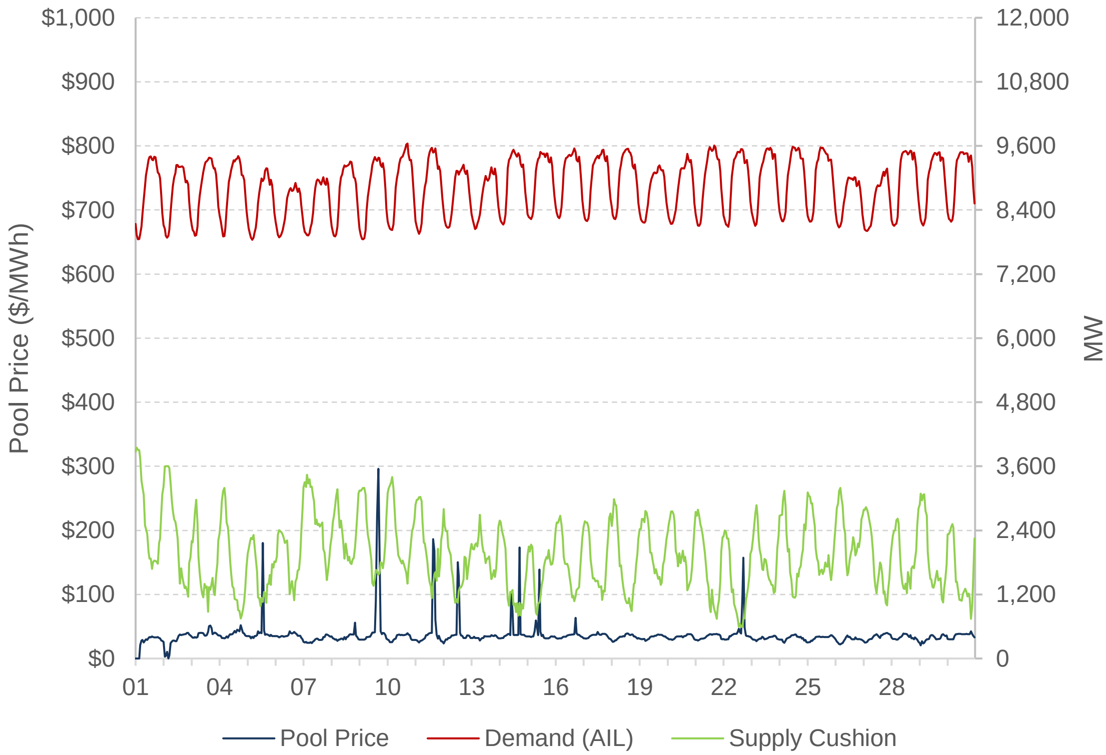
Pool prices were less volatile in September with an average of $36.05/MWh. This lower monthly average was largely the result of less high-priced hours in September, with a maximum hourly price of $296/MWh compared with $780/MWh in July and $716/MWh in August. Figure 10 shows pool price, total demand, and supply cushion over the course of September.

As shown, the month started with some very high supply cushions during the off-peak and pool prices settled at $0/MWh for HE24 of August 31 and HE1-4 of September 1, indicating supply

[8] Hourly temperatures used are the average of temperatures in Calgary, Edmonton and Fort McMurray.

surplus conditions were in effect for the duration of these hours. It is unusual to see supply surplus this late in the year as water supply to hydro generation, both imported and domestic, is normally reduced. High levels of wind generation contributed to this event with an average of 1,462 MWh while net imports were scheduled for 784 MWh in HE24 of August 31.

Figure 10: Demand, supply cushion, and pool price (September 2020)



Year-over-year AIL demand was 3.4% lower in September 2020, a material improvement compared to the prior two months, and driven by a lower decline in demand which was met by on-site generation, with system load down 3.5% year-over-year (see Table 3).

Table 3: Percentage change in demand year-over-year (July to September)

Month	Total Demand (AIL)	System Load	Demand met by on-site generation
July	-5.4%	-3.6%	-10.4%
August	-5.0%	-1.1%	-15.5%
September	-3.4%	-3.5%	-3.2%

System load calculates the power that was consumed from the Alberta grid, and also includes transmission losses.[9] Demand met by on-site generation is an estimate of power that was produced and consumed on the same site, and normally reflects large industrial loads that have developed their own generation (e.g., an oilsands load with cogeneration).[10] The improvement in demand served by on-site generation in September indicates some large industrial loads increasing operations or returning online.

AIL was still 126 MWh lower in September compared to August on average, with moderate temperatures observed for most of September. As shown by Figure 10, hourly AIL barely went above 9,600 MWh in September. Table 4 below illustrates that a decline in system load, 259 MWh on average, was the main cause of the fall in AIL from August to September. The estimated demand met by on-site generation increased by 133 MWh.

Changes in system load, such as the decline from August to September, will generally have more of an impact on pool prices because these changes will require an offsetting change in net supply to the grid, whereas for changes in demand served by on-site generation there is often an offsetting change in generation on-site and so the demand change does not necessarily impact market prices. In some instances, changes in demand met by on-site generation can cause opposing changes in system load. For example, when a generator on-site goes out-of-service the site may consume more power from the Alberta grid, increasing system load. The extent of this kind of substitution may be limited by the site's transmission connection to the grid.

Table 4: AIL, system load, and demand met by on-site generation

Month	AIL (MWh) [A]		System Load (MWh) [B]		Demand met by on-site generation (MWh) ([A] – [B])	
	Average	Monthly Change	Average	Monthly Change	Average	Monthly Change
Jul	8,974	235	6,705	217	2,269	18
Aug	8,971	-3	6,824	119	2,147	-122
Sep	8,845	-126	6,565	-259	2,280	133

On the supply-side, wind generation was higher in September, averaging 592 MWh, a 33% capacity factor. However, this average does not reflect the volatility in supply inherent in wind generation. Figure 11 on the following page illustrates hourly wind generation across September. As shown, the average level of wind generation for the month was increased by some high generation hours towards the beginning and end of the month, but in some hours wind generation was very low.

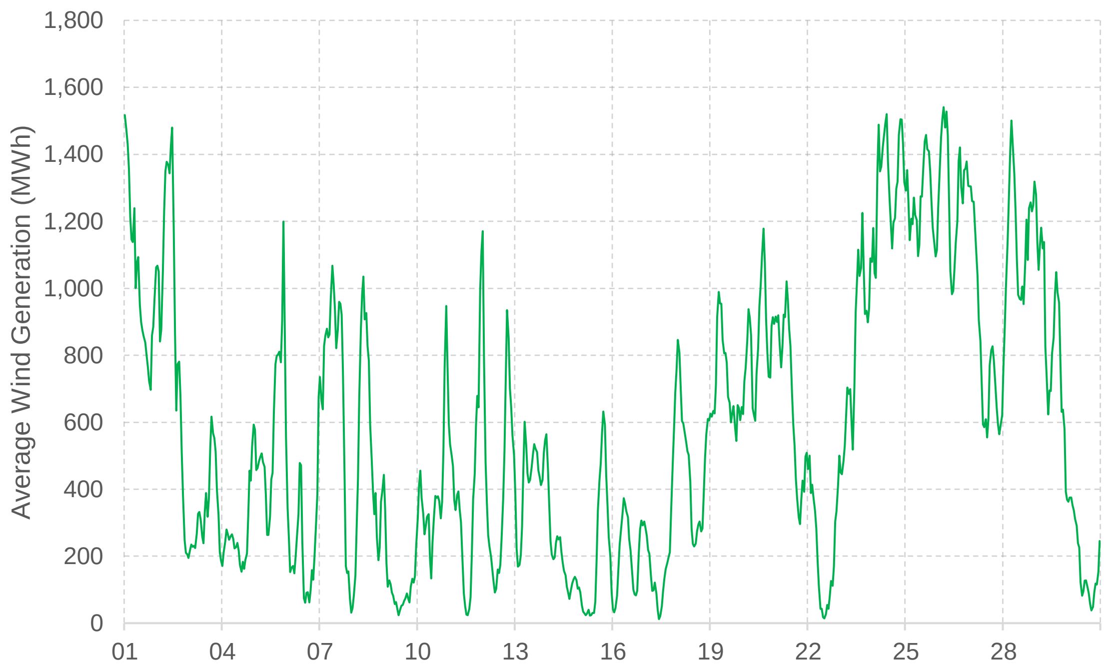
[9] System Load means the total, in an hour, of all metered demands under *Rate DTS, Rate FTS* and *Rate DOS* of the ISO tariff plus transmission system losses (AESO consolidated authoritative document glossary).

[10] Demand met by on-site generation is estimated by subtracting system load from AIL.

The flow of imports into Alberta was materially lower in September, with net imports averaging 120 MWh compared with 772 MWh during August. This was likely caused by the seasonal reduction in water supply to the hydro generators in the Pacific Northwest region and also because of the lower pool prices observed in September. Prices in California spiked again on the Labour Day weekend with SP15 real-time hourly Locational Marginal Prices (LMPs) on September 5 and 6 peaking at CAD$1,317/MWh and CAD$1,502/MWh respectively, as the region dealt with hot weather and wildfires.[11]

Low wind generation and reduced net imports did combine with thermal outages on some days to lower the supply cushion during peak hours (see Figure 10). However, these hours did not see the level of pool prices observed in July and August. For example, during the peak hours of Tuesday, September 22 supply cushion fell to 590 MW in HE17 with two large coal plants on outage, only 200 MWh of net imports and 80 MWh of wind generation. The pool price for this hour settled at $96/MWh.

Figure 11: Wind generation by hour (September 2020)



1.3 Supply surplus events

Supply surplus occurs when the System Marginal Price (SMP) equals $0/MWh (the price floor). This indicates that there may be more generation and imports supplying the market at $0/MWh than the total amount of consumption. This normally happens during off-peak hours when demand is low and when there is a large amount of supply from imports and/or wind generators. Spring to early summer is the most common time period for these events to occur because of the increased

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[11] NY Times: Fire and Heat Hit California, Again – September 8, 2020

hydro supply, both imported and domestic. In combination with the must-run capacity of domestic thermal and hydro plants, the supply of imports and wind can mean that the AESO must act administratively to reduce supply in order to maintain system reliability.

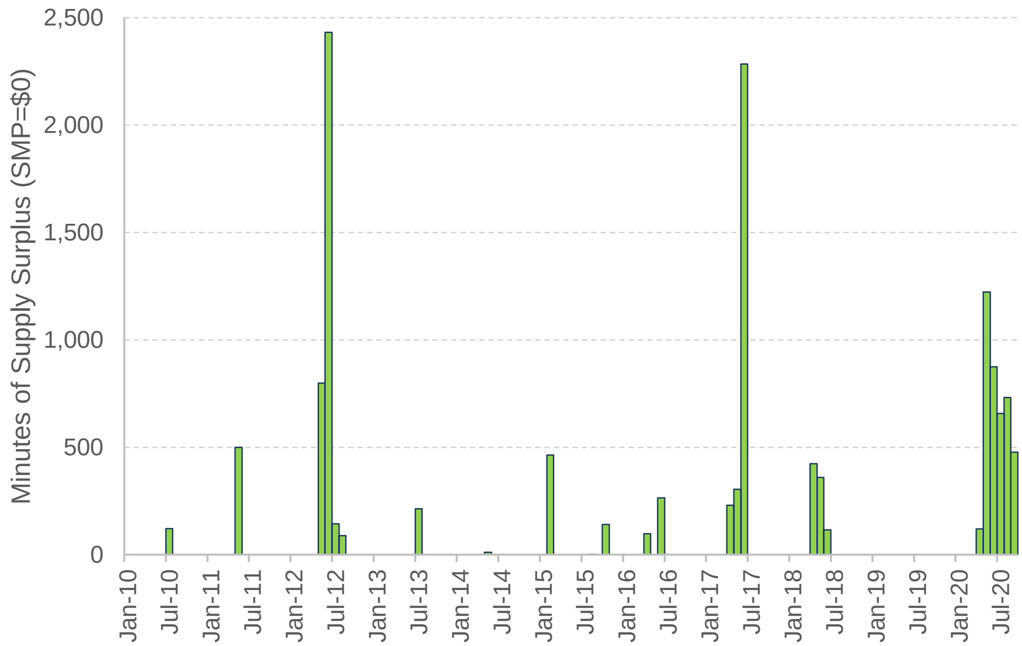
For suppliers, generating at $0/MWh can make economic and operational sense. In particular, imports may be coming from a market where prices are negative, wind generators have very low variable costs and some receive other payments associated with their supply, and thermal generators face significant shutdown and start-up costs.

Figure 12 illustrates the minutes of supply surplus by month since 2010. The year 2020 now has the highest number of minutes where SMP was $0/MWh with 4,083 minutes, compared with the previous high of 3,461 minutes in 2012. By quarter, Q2 2012 and Q2 2017 both had high levels of supply surplus with 3,230 and 2,819 minutes respectively, while Q2 2020 recorded 2,218 minutes. The supply surplus levels in Q2 2012 and Q2 2017 were largely driven by market conditions in June. In 2020 the occurrence of supply surplus has been more consistent throughout Q2 and Q3 (see Figure 12). For example, Q3 2020 observed 1,865 minutes of supply surplus, which is substantially higher than any Q3 on record; the previous high was 231 minutes in Q3 2012.[12] A high level of imports late into the summer, increased wind generation, and reduced demand levels were all market factors raising the minutes of supply surplus in Q3 this year. Overall, supply surplus is still a relatively rare occurrence at present, accounting for 1.4% of minutes in Q3 2020 and 1.7% in Q2 2020.

In Q3 2020 there were sixteen supply surplus events and the AESO managed six of them by limiting imports. Management of the other ten supply surplus events did not require any involuntary mitigation action by the AESO. Limiting imports is the first involuntary measure set out in ISO rule 202.5, *Supply Surplus*, which governs such situations. The reason that limiting imports is the first step is because they are considered an opportunity service.

[12] Record for the period from January 1, 2000 to September 30, 2020.

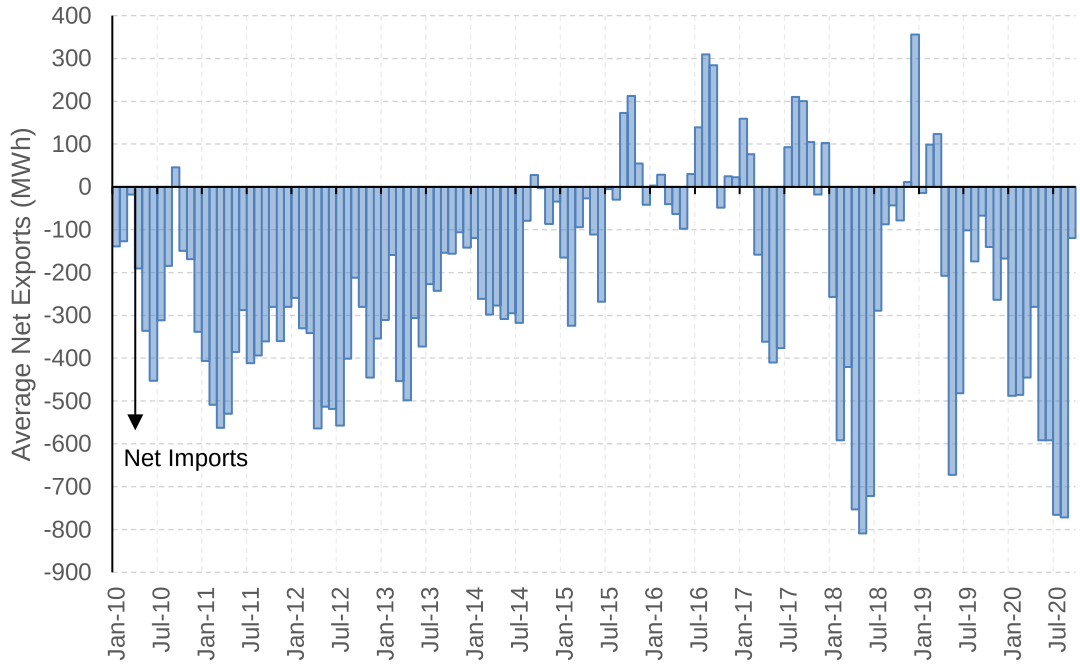
Figure 12: Minutes of supply surplus by month (January 2010 to September 2020)



1.4 Interties

Despite a BC/MATL intertie outage on the weekend of July 25-26 and high prices in California on some days in August, overall net imports into Alberta during July and August this year were exceptionally high. On average, net imports into Alberta were 766 MWh in July and 772 MWh in August. For perspective, the highest monthly volume of net imports since January 2001 occurred in May 2018, when net imports were 809 MWh on average. Figure 13 shows average net exports by month since 2010.

Figure 13: Average hourly net exports by month (January 2010 to September 2020)



1.4.1 BC/Montana intertie

The BC/MATL intertie consists of interconnections to British Columbia and Montana and is Alberta's largest intertie, allowing participants to flow power to and from power trading hubs such as Mid-Columbia (Mid-C) and California. An efficient market is expected to result in electricity flowing from places where price (and cost) is low to where price (and cost) is high. This is expected to occur as a result of traders scheduling exports from low price markets and associated imports into high price markets.

Figure 14 shows a scatterplot of hourly net exports on BC/MATL against the hourly Mid-C less Alberta pool price differential in Q3 2020. Points in the top-right and bottom-left quadrants indicate the direction of net flow on BC/MATL was economic based on realized prices in Mid-C and Alberta, with the bottom-left quadrant indicating that the Alberta pool price was greater than the prevailing price in Mid-C and the hour observed net imports into Alberta. As shown, there is a large cluster of points just under the horizontal axis and to the left, indicating a large number of hours in which Alberta pool prices were slightly higher than Mid-C prices and there were net flows of power into Alberta. There are also some uneconomic hours observed when Alberta pool prices were lower than prices in Mid-C but a net flow of imports into Alberta was still observed.

Figure 14: Scatterplot of BC/MATL net exports and Mid-C - Alberta price differential (Q3 2020)[13]

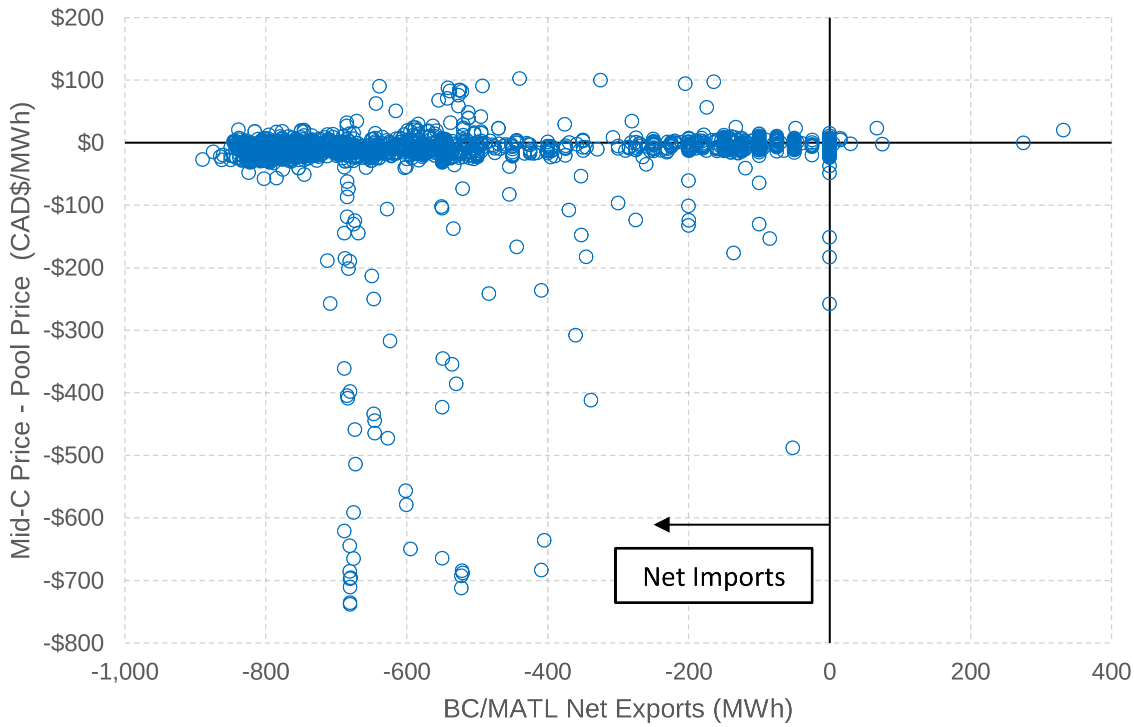


Figure 15 illustrates the distribution of net exports on BC/MATL in Q3 2020. The total height of each bar indicates the percentage of hours when net exports were within a certain range. For example, in 37% of hours Alberta observed net imports of between 600 and 799 MWh, and in 20% of hours net imports were between 400 and 599 MWh. Within each bar there is a breakdown indicating the realized price differentials within this group. For example, 18% of hours in the quarter saw between 600 and 799 MWh of net imports and a realized Mid-C less Alberta price differential of between -$10 and -$30. In 13% of hours the price differential was between -$10 and $0 and net imports were between 600 and 799 MWh, indicating a strong flow of power into Alberta given the small price difference. One potential explanation here is that traders may have assessed a higher upside risk to pool prices in Alberta relative to the price of purchasing power from Mid-C.

In a small number of hours, Alberta observed a strong flow of imports even though the pool price turned out to be lower than prices in Mid-C. While these results are not strictly efficient, it is important to remember that imports into Alberta must be scheduled more than two hours before the start time of the scheduled hour, when realized pool prices are not known.

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[13] Mid-C prices were converted from USD to CAD using Bank of Canada's daily exchange rate.The dataset is missing four days of Mid-C prices in August (August 4-5 and 7-8) and eight days of Mid-C prices in September (September 1-8). These hours are excluded from this analysis.

Figure 15: The distribution of net exports and Mid-C - Alberta price differentials (Q3 2020)[14]

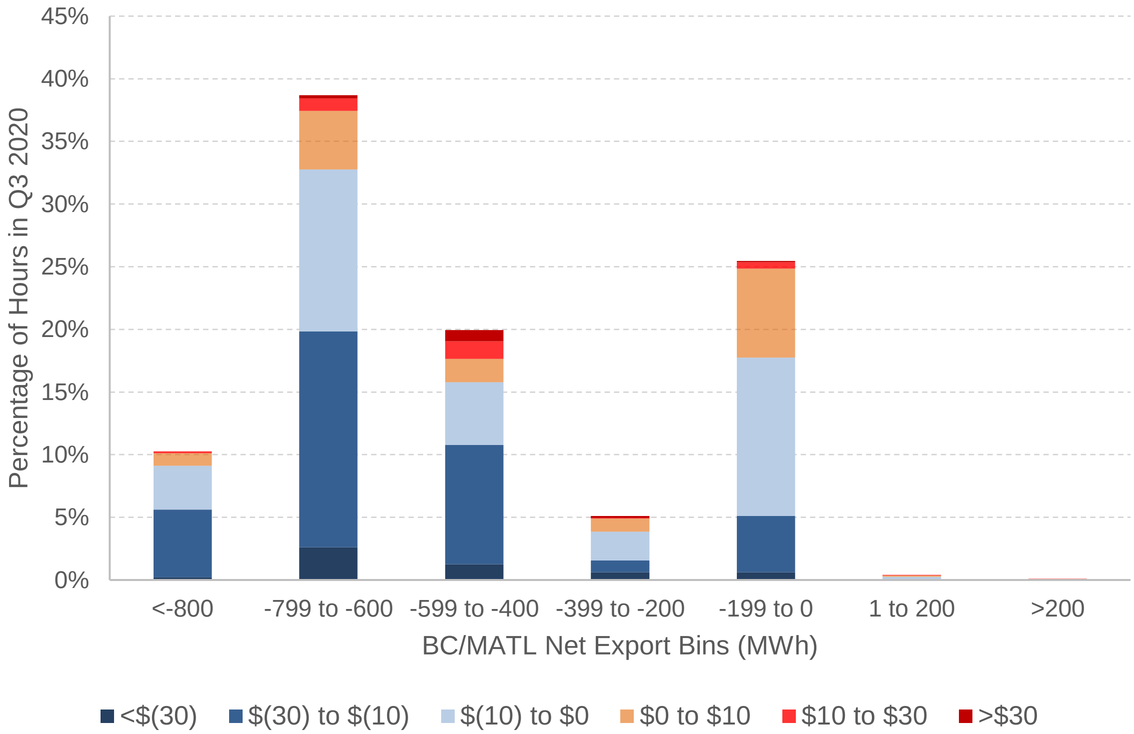


Figure 14 and Figure 15 do not consider some elements of intertie transactions that are relevant and that vary between participants, including:

- transmission access costs through all the jurisdictions that the energy flows; and
- losses and ancillary services costs applied by each jurisdiction.

The Mid-C market typically trades 1-hour ahead of the flow of energy, whereas the Alberta market is a 2-hour ahead market. This causes a misalignment between the two markets that traders must manage. While the price of a transaction in Mid-C is agreed at the time of the transaction and thus known before the flow of energy, the Alberta pool price is not known until after the energy has flowed.

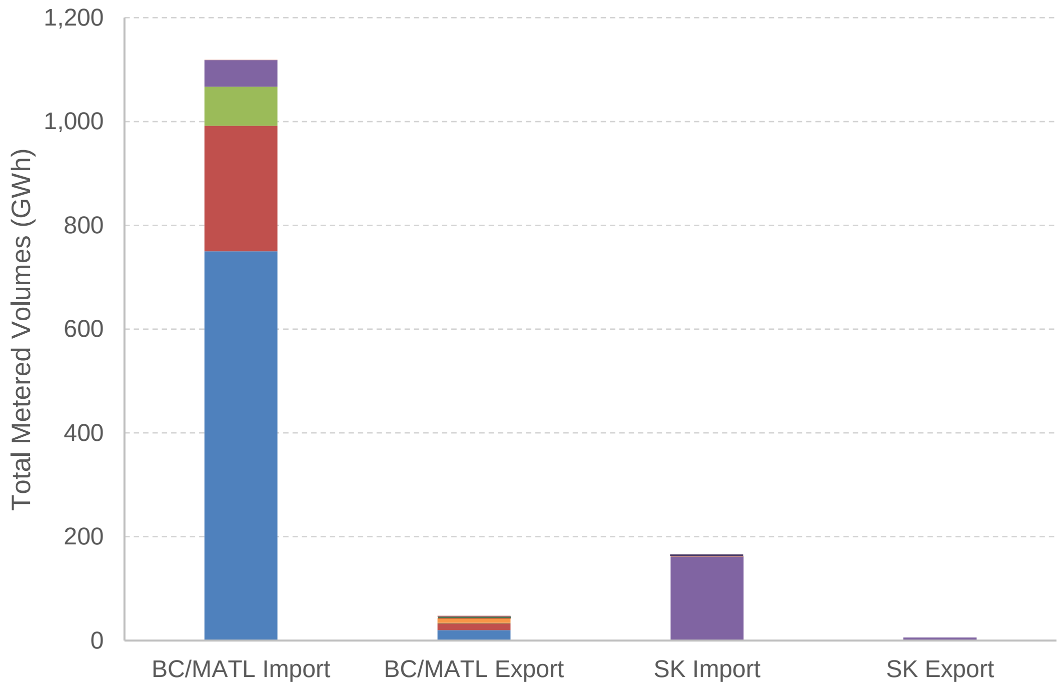
In addition, the figures do not provide information about the entities flowing energy and their motivations. While some entities may flow energy for portfolio reasons, it is anticipated that any significant arbitrage opportunities will be exploited. The terms and conditions of transmission access on the interties are such that it is very difficult to economically withhold transmission capacity.

[14] The dataset is missing four days of Mid-C prices in August (August 4-5 and 7-8) and eight days of Mid-C prices in September (September 1-8). These hours are excluded from this analysis.

1.4.2 Participation on the interties

A relatively small number of market participants schedule electricity trades on Alberta's interties. The market shares of market participants on Alberta's interties with (i) British Columbia and Montana and (ii) Saskatchewan in Q3 2020 are illustrated in Figure 16. The figure shows the high level of imports into Alberta on the BC/MATL intertie. The limited number of intertie participants means that the MSA closely monitors this aspect of the electricity market to ensure fair, efficient, and open competition.

Figure 16: Intertie flows by market participant in Q3 2020



1.4.3 Load Shed Service for Imports (LSSi)

LSSi is an ancillary service procured by the AESO to facilitate higher volumes of imports into Alberta. LSSi allows the AESO to increase the ATC of the BC/MATL intertie by contracting with Alberta loads to trip power consumption in the event that system frequency decreases due to the intertie tripping offline when import volumes are high. LSSi providers are paid for availability, arming, and tripping in the event they are tripped to arrest the drop in frequency.

The AESO implemented changes to the LSSi table, effective June 22, 2020 and more recently on August 12, 2020, to include LSSi requirements for severe weather conditions.[15] As discussed in the MSA's Q2 report, the LSSi table change on June 22 increased the volume of LSSi the AESO

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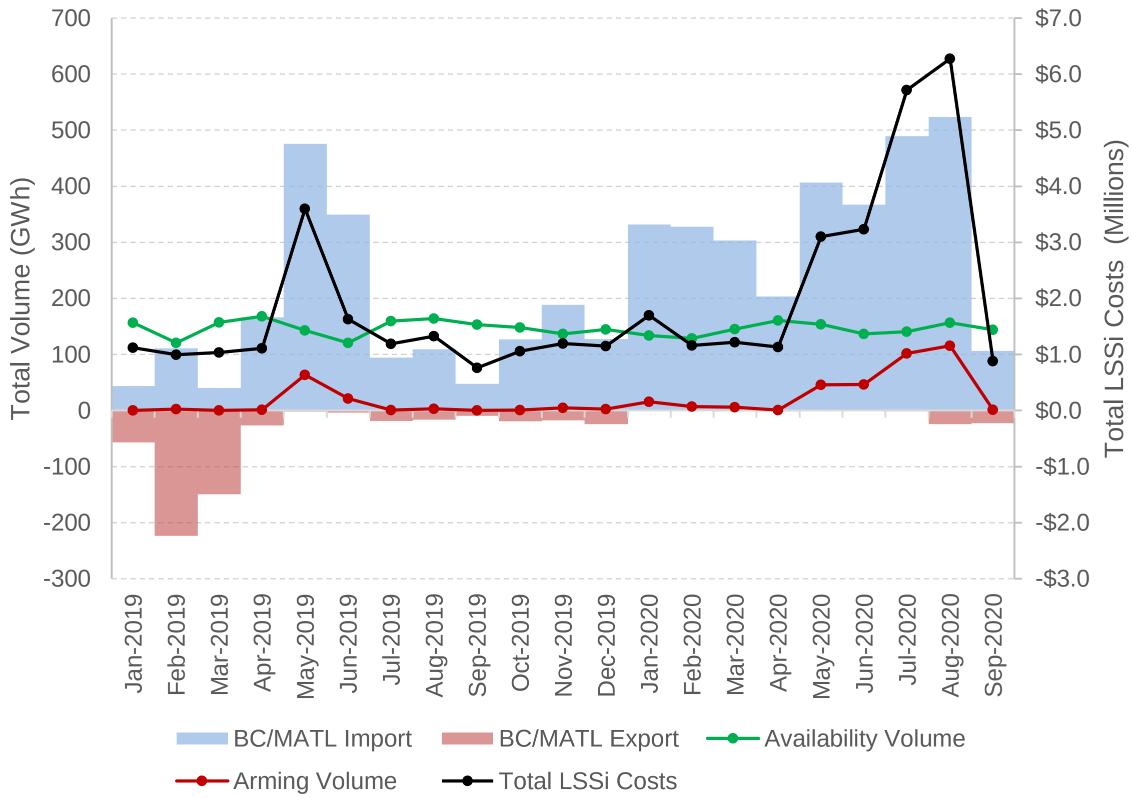
[15] AESO ID#2011-001R, ATC and Transfer path Management, effective August 12, 2020 (page 12 of 21)

is required to procure. LSSi costs increased significantly in July and August 2020. This increase reflected the changes to the LSSi table, and high import volumes. As of September 30 estimated costs for LSSi so far in 2020 were $24 million,[16] 92% more than the same time in 2019 (see Figure 17).

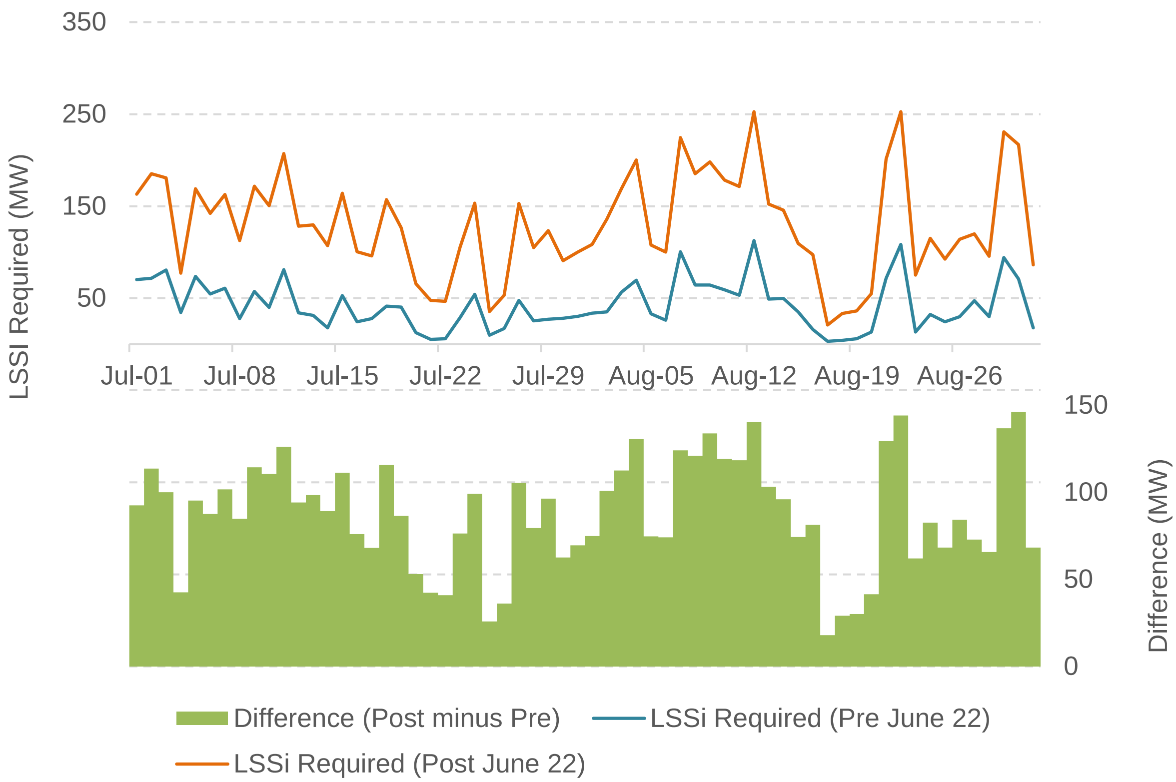
Figure 17: BC/MATL imports and exports, LSSi volumes, and LSSi costs by month (January 2019 to September 2020)



The MSA compared the change in LSSi volumes due to the change in the table in the period after June 22, 2020 (see Figure 18). Using Alberta Internal Load (AIL) and net imports on the BC/MATL flow gate for July and August, LSSi requirements were calculated, capping them at observed offered LSSi volumes. The resulting chart shows that on average over July and August, 60 MW of additional LSSi was required under the new regime. LSSi was not required for most of September, under either the old table or the new one, as import volumes fell considerably.

[16] LSSi estimates subject to settlement adjustments

Figure 18: Daily average LSSi requirements before and after the table change



On September 17, 2020, the AESO opened the Request for Expressions of Interest stage of its LSSI procurement competition. The Request for Proposals stage of the competition will open on October 28, 2020. The AESO has indicated that the target procurement volume is between 300 and 500 MW, but it may procure outside the target range.[17] Contracts are expected to be awarded in late Q1 2021 for delivery in 2022.

1.5 Generation by fuel type

Figure 19 illustrates Alberta's total generation by fuel type, and imports, from January 2015 through to September 2020. As shown, there has been a marked decline in coal generation during this period. In 2015, coal generators supplied 49% of Alberta's electricity, whereas in Q1 to Q3 of 2020 they supplied 28%. The decline in coal generation has been offset by increases in cogeneration (+7% share of total supply), combined cycle (+6%), imports (+4%), and wind (+2%).

In late July 2020 the retirement of the Sundance 3 coal unit was announced.[18] The unit was last online in April 2018 and was mothballed until retiring. The Sundance 5 unit remains mothballed.

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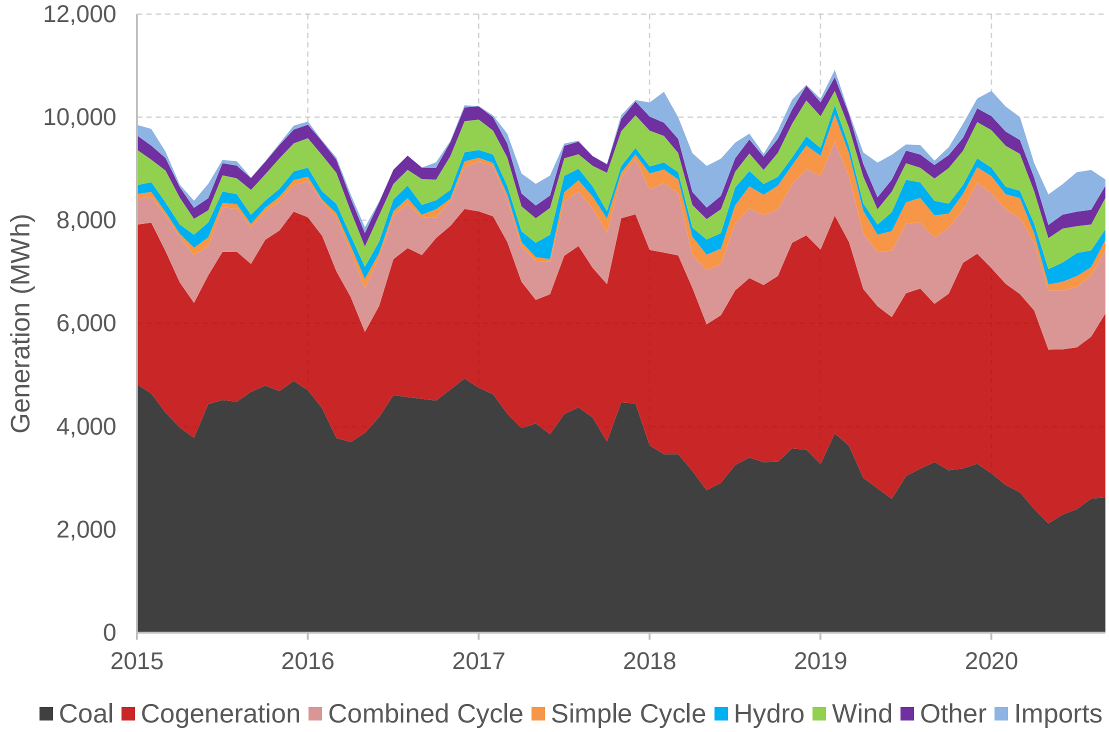
[17] AESO LSSi Procurement Competition, Questions and Answers (page 7) – October 6, 2020

[18] Newswire – July 22, 2020

Figure 19: Average monthly generation by fuel type (January 2015 to September 2020)[19]



The decline in coal generation over time has been due to a number of factors including:

- changes to the way carbon emissions are priced in Alberta (discussed below);
- the continued development of on-site cogeneration at large industrial facilities;
- the commissioning of the Shepard Energy Centre, a large (870 MW) combined cycle plant, which began commercial operations in early 2015; and
- low prevailing prices for natural gas.

Alberta's carbon pricing has been in place since 2007 when a carbon price of $15/tCO2e and a reductions target of 12% were introduced under the *Specified Gas Emitters Regulation* (SGER). The price on carbon was later increased to $20/tCO2e in 2016 and the reductions target was increased to 15%. In 2017 the price of carbon was increased further to $30/tCO2e and the reductions target was increased to 20%. In 2017, a coal unit with an emission intensity of 1.0 tCO2e/MWh would have had carbon costs of $6/MWh.

[19] Imports show the average net imported volume of electricity by month. For hours in which Alberta was a net exporter of power, imports are set equal to 0 MWh.

In 2018, the *Carbon Competitiveness Incentive Regulation* (CCIR) replaced SGER. Under CCIR, the emissions of thermal generation assets were benchmarked against the “good-as-best-gas”, or an emissions intensity of 0.37 tCO2e/MWh. With a carbon price of $30/tCO2e a coal asset with an emissions intensity of around 1.0 tCO2e/MWh now had carbon costs in the region of $19/MWh. For perspective, the fuel cost for an efficient combined cycle generator was around $12/MWh in 2018, when gas prices averaged $1.44/GJ.[20]

The *Technology Innovation and Emission Reduction Regulation* (TIER) replaced CCIR on January 1, 2020 and is the existing carbon emission regime in Alberta. TIER left the price of carbon at $30/tCO2e for 2020 and also maintained the benchmarking of emissions intensity in place under CCIR.

With the transition from SGER to CCIR (and later TIER), the main short-run implication for the power pool was that the short-run marginal cost of supply from coal went from being less than natural gas to being more than natural gas. Corresponding changes in offer prices led to reduced dispatch of coal generation and therefore, as indicated above, reduced carbon emissions.

Looking forward, the price of carbon is scheduled to increase to $40/tCO2e in 2021 and $50/tCO2e in 2022. There is currently some degree of uncertainty regarding the details of carbon prices beyond 2022. This results in cost uncertainty which may affect the willingness of market participants to buy or sell power for delivery after 2022.

1.6 Cascade combined cycle project development

The Cascade combined cycle project closed financing and began construction at the end of August. The proposed 900 MW asset could supply up to 8% of Alberta’s electricity demands in the coming years. The project is being developed by a number of parties and is scheduled to begin commercial operations in 2023.[21]

Substantial capital investments of this sort are positive indicators for Alberta’s energy-only electricity market and will result in Alberta continuing to reduce carbon emissions from its electricity sector.

[20] ICE NGX AB-NIT Same Day (2A) index

[21] Financial Post – August 28, 2020

2 THE MARKETS FOR OPERATING RESERVES

There are three types of operating reserves which system controllers in Alberta use when there is an unexpected imbalance or lagged response between supply and demand: regulating reserves, spinning reserves and supplemental reserves. Regulating reserves provide an instantaneous response to an imbalance of supply and demand, whereas spinning reserves are synchronized to the grid and provide capacity which the system controller can call upon in a short amount of time. Supplemental reserves are not required to be synchronized but must be able to synchronize quickly if called upon by the system controller.[22]

2.1 Costs and procurement volumes

In Q3 2020, as reported in Table 5, the total cost of operating reserves was 8% lower than the same quarter the previous year. The primary driver of these costs is pool price which in Q3 2020 was down 6% from Q3 2019; however, standby activation costs[23] increased by 521%, precipitated by high volumes. Standby activation volumes increased by 540% in Q3 2020, primarily to support high levels of imports on the BC/MATL interconnection, especially in July and August.

The AESO procured 14% less active regulating reserves compared to the same quarter the previous year. The requirement to procure contingency reserves is set out in the Alberta Reliability Standards but it is up to AESO to determine how much regulating reserve is required to meet the needs of the system. All else equal, less regulating reserve is required in the system when there is a more accurate link between load changes and dispatch changes in the energy merit order.

Active spin and supplemental reserves volumes were down 1% compared to Q3 2019, partly due to the reduced load in Alberta. Exceptionally high imports, particularly in July and August, necessitated the use of standby reserves to support the intertie.

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

[23] Standby reserves are activated when active reserves are insufficient. This increases standby activation costs.

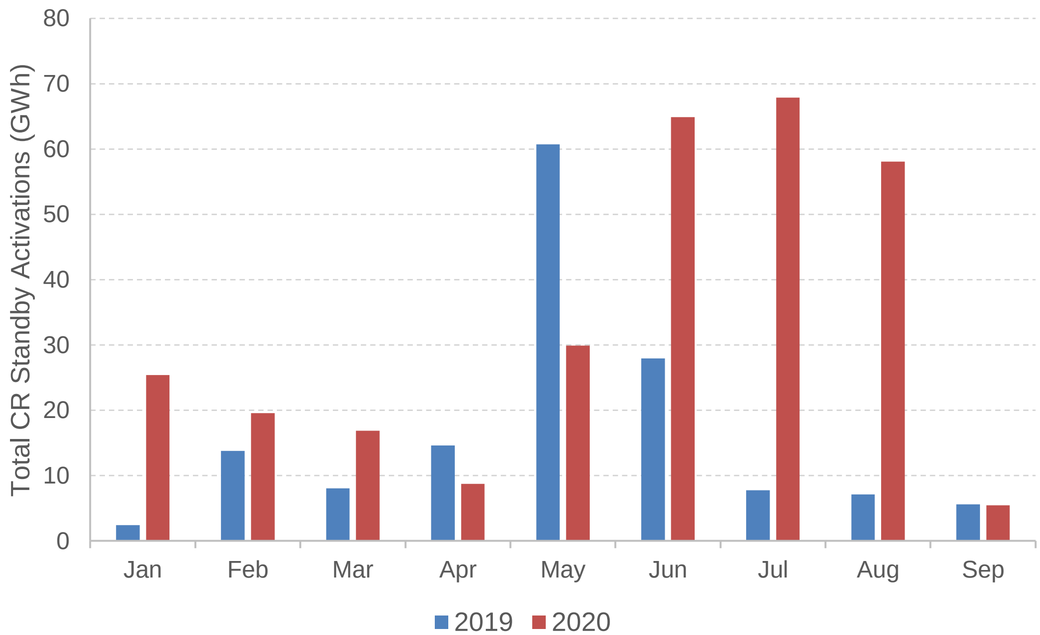
Table 5: Detailed breakdown of operating reserves costs in Q3 2020

Total Cost ($ Millions)						
	Jul-20	**Aug-20**	**Sep-20**	**Q3 2020**	**Q3 2019**	***% Change***
Active Procured	**11.3**	**6.9**	**3.7**	**21.9**	**29.5**	***-26%***
RR	1.5	2.1	1.6	5.2	12.7	*-59%*
SR	5.3	2.8	1.4	9.5	9.9	*-4%*
SUP	4.5	2.0	0.8	7.3	6.9	*5%*
Standby Procured	**0.1**	**0.2**	**0.2**	**0.5**	**1.5**	***-65%***
RR	0.1	0.1	0.1	0.3	1.0	*-75%*
SR	0.1	0.1	0.1	0.3	0.4	*-38%*
SUP	0.0	0.0	0.0	0.0	0.1	*-78%*
Standby Activated	**3.3**	**3.6**	**0.2**	**7.2**	**1.2**	***521%***
RR	0.1	0.1	0.0	0.2	0.0	*635%*
SR	2.4	2.7	0.2	5.3	0.8	*554%*
SUP	0.8	0.9	0.0	1.7	0.3	*431%*
Total	**14.7**	**10.7**	**4.2**	**29.7**	**32.2**	***-8%***
Total Volume (GWh)						
	Jul-20	**Aug-20**	**Sep-20**	**Q3 2020**	**Q3 2019**	***% Change***
Active Procured	**446.1**	**446.6**	**407.6**	**1,300.2**	**1,360.5**	**-4%**
RR	101.7	101.3	95.0	298.0	348.0	*-14%*
SR	172.4	172.6	156.4	501.5	506.3	*-1%*
SUP	172.0	172.6	156.1	500.8	506.1	*-1%*
Standby Procured	**163.1**	**163.3**	**158.0**	**484.4**	**502.4**	***-4%***
RR	59.4	59.5	57.6	176.5	175.8	*0%*
SR	78.0	78.1	75.4	231.5	240.5	*-4%*
SUP	25.7	25.8	25.0	76.4	86.1	*-11%*
Standby Activated	**69.5**	**60.6**	**6.3**	**136.3**	**21.3**	***540%***
RR	1.6	2.5	0.8	5.0	0.8	*531%*
SR	45.3	38.3	3.7	87.3	12.7	*588%*
SUP	22.6	19.8	1.7	44.0	7.8	*462%*
Total	**678.7**	**670.5**	**571.8**	**1,921.0**	**1,884.2**	***2%***
Average Cost ($/MWh)						
	Jul-20	**Aug-20**	**Sep-20**	**Q3 2020**	**Q3 2019**	***% Change***
Active Procured	**25.24**	**15.47**	**9.17**	**16.85**	**21.70**	**-22%**
RR	14.39	21.11	16.32	17.29	36.54	-53%
SR	31.00	16.03	8.86	18.94	19.51	-3%
SUP	25.88	11.60	5.13	14.49	13.68	6%
Standby Procured	**0.88**	**0.96**	**1.41**	**1.08**	**2.97**	**-64%**
RR	1.42	1.64	1.25	1.44	5.79	-75%
SR	0.74	0.74	1.85	1.10	1.71	-36%
SUP	0.07	0.05	0.45	0.19	0.76	-75%
Standby Activated	**48.05**	**60.08**	**39.79**	**53.01**	**54.60**	**-3%**
RR	40.03	45.58	42.55	43.27	37.16	16%
SR	53.90	69.46	44.66	60.33	63.47	-5%
SUP	36.89	43.75	27.90	39.62	42.00	-6%
Total	**21.72**	**15.97**	**7.36**	**15.44**	**17.08**	***-10%***

2.1.1 *Standby contingency reserves*

The volumes of activated standby contingency reserves (spinning and supplemental) were high in June, July, and August this year (see Figure 20). This was primarily the result of high import volumes and the need to have sufficient contingency reserves in Alberta to deal with a potential intertie trip. The high levels of standby activations in periods when imports are high means there is a much higher percentage of standby being activated compared to periods when import volumes are lower. For example, in July, 88% of the total standby supplemental reserves purchased were activated as were 65% of spinning reserves. In September, the activation rates were 7% and 5% for supplemental and spinning reserves, respectively.

Figure 20: Total standby activations for contingency reserves by month (January to September 2019 and 2020)



As discussed above, in mid-August there was a brief period of high pool prices in some peak hours between August 16 and 19, as shown in Figure 7. Table 6 below summarizes those four days, with high on-peak pool prices leading to high active reserve costs. The link between pool prices and active reserves is based on the opportunity cost of providing reserves largely being the inability to provide, and be paid for providing, energy.

Conversely, standby reserve sellers must bid two parameters: a premium price and an activation price. The premium is the price paid by the AESO for availability. The activation price is the fixed price received if the asset is activated to provide reserves. When pool prices are expected to be high, sellers tend to increase their prices for activation. This is because there is an opportunity cost of providing energy and sellers are uncertain about future pool prices, how much they will be activated, and in which hours. This is evident in Table 6 as activated standby reserves were significantly more expensive than active reserves and, indeed, much more than the energy market prices.

Table 6: Summary statistics for pool price and contingency reserve costs (August 16 to 19)[24]

Date	On-peak pool price ($/MWh)	On-peak active spin cost ($/MW)	On-peak active supp cost ($/MW)	On-peak activated standby spin cost ($/MW)	On-peak activated standby supp cost ($/MW)
Aug-16	$93	$66	$52	$67	$78
Aug-17	$118	$90	$82	$318	$254
Aug-18	$73	$39	$34	$374	$444
Aug-19	$159	$126	$113	$341	$315

If only a small number of MW of standby reserves are needed in real time, there may be limited concern. However, as noted above, significant volumes of standby contingency reserves were activated throughout July and August. In the case of the August 16 to 19 on-peak period, 30% of total standby contingency reserves were activated. In this period some volumes were exporting through Montana to California, reducing the overall import level on the BC/MATL intertie in some hours and hence lowering the requirement for standby activations.

Energy prices on Sunday, August 16 appeared higher than expected by sellers of reserves. The operating reserves are purchased by the AESO on the nearest business day before delivery. Generally operating reserves are purchased by the AESO the day before delivery, although they can be purchased three or four days before delivery before weekends and holidays. These forward sales require sellers of standby reserves to take a view on expected pool price.

The MSA has previously highlighted that there could potentially be some improvements made to the standby OR market design, and the outcomes observed in August 2020 corroborate the MSA's prior commentary.[25] In particular, the MSA notes several issues with the current design of the standby market, including:

- Fixed price activation: the standby OR prices should be indexed to pool price.
- Two parameter bid process: the fixed activation rate of 10% built into the auction clearing process for spin and sup clearly varies with market circumstances (such as imports) that sellers can foresee. Therefore the fixed rate of 10% for spin and sup, which may have been reasonable historically, is not appropriate in the current situation.

It is worth noting that Alberta is the only energy market that procures standby reserves.

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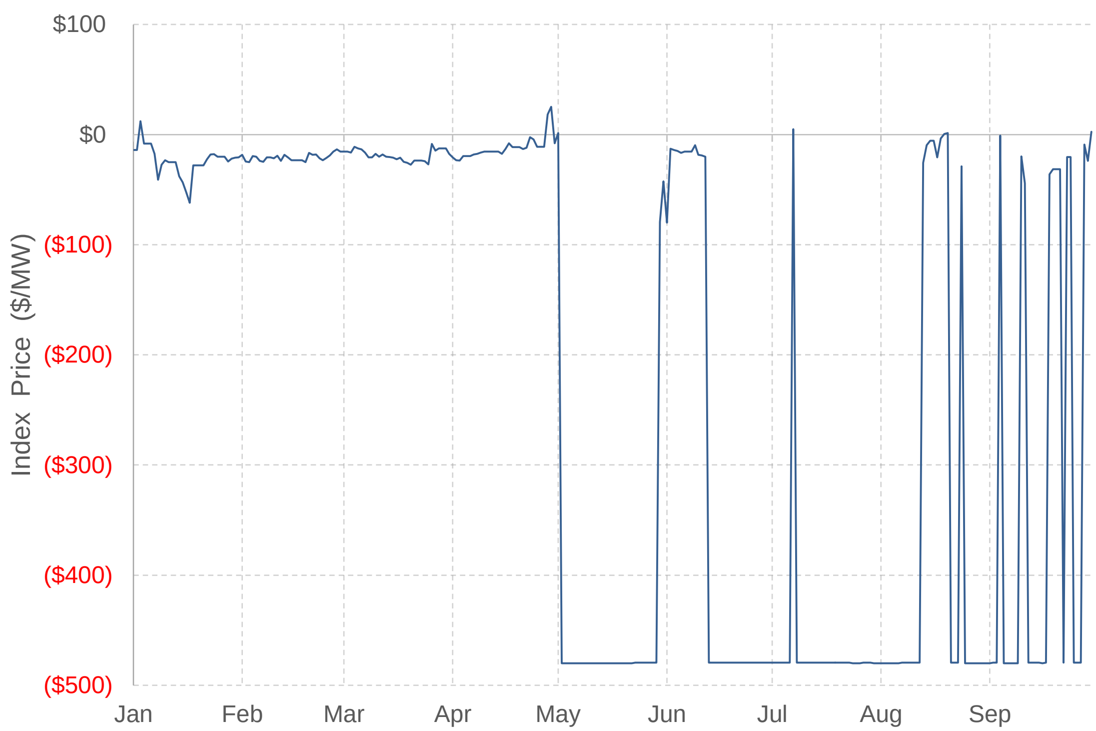
[24] The activated cost of standby is a volume-weighted average and does not include the premiums that were paid to all sellers in the on-peak hours.

[25] See previous MSA quarterly reports: Q1 2020 (page 14), Q2 2020 (page 24), Q1 2018 (page 20), Q2 2018 (page 42), and Q4 2018 (page 17)

2.1.2 On-peak regulating reserves

Figure 21 shows the index price for on-peak regulating reserves ("RR") for January through September. The index is to pool price so, for example, if the index price is negative $20/MW and pool price is $45/MWh then suppliers of on-peak RR are paid $25/MW. Suppliers of RR are also paid pool price for the energy they provide to the grid while providing the service. Suppliers of RR (as for all active OR products) will never pay to provide it. If the sum of pool price plus the index price is negative, suppliers of RR receive $0 for the service; however, they are still paid pool price for any energy provided to the grid.

Figure 21: Index price for on-peak regulating reserves (January 1 – September 30 2020)



As shown in Figure 21, the index price for on-peak RR has been close to -$500/MW for most days since the beginning of May. One market participant has financial obligations that are based on the settled price for RR, so for that participant it may make sense to offer some RR at very low prices.[26] However, the MSA has observed that multiple participants in the on-peak RR market are offering at very low prices, and this is driving the market to the point where on-peak RR has been essentially free (outside of energy costs) for five months.

[26] In the same way that a market participant has incentive to generate when it has a forward sale of energy subject to it being cheaper to generate than to buy from the market.

3 THE FORWARD MARKET

Table 7 shows total volumes for standard products from Q1 2016 onward. Standard products include contracts, such as flat and extended peak, but do not include custom shapes, such as the full-load RRO trades. The MSA's analysis in this section incorporates data on direct bilateral trades up to and including Q2 2020. These bilateral trades occur directly between the two trading parties, not via ICE NGX or through a broker, and the MSA generally collects information on these transactions once a year. The direct bilateral trades account for 9% of the total volumes shown in Table 7 between Q1 2016 and Q2 2020, with a large volume of direct bilateral trades executed in early 2016.

Table 7: Total volumes by trade date, standard products only (TWh)[27]

		Daily	Monthly	Quarterly	Annual	Other	Total
2016	**Q1**	0.22	9.40	2.00	12.92	8.38	32.92
	Q2	0.23	8.33	0.65	5.05	4.87	19.13
	Q3	0.08	6.84	1.23	4.69	0.40	13.24
	Q4	0.10	5.54	1.71	3.92	0.70	11.97
	Year	**0.63**	**30.12**	**5.58**	**26.58**	**14.35**	**77.26**
2017	**Q1**	0.06	6.66	3.06	4.61	1.94	16.33
	Q2	0.14	7.02	2.35	11.48	1.34	22.34
	Q3	0.19	6.90	2.21	6.10	1.29	16.70
	Q4	0.06	8.34	3.54	7.80	2.06	21.81
	Year	**0.45**	**28.93**	**11.16**	**30.00**	**6.64**	**77.17**
2018	**Q1**	0.15	7.33	0.61	4.69	0.63	13.41
	Q2	0.17	6.13	1.22	5.93	0.65	14.10
	Q3	0.10	4.62	0.25	3.82	0.68	9.46
	Q4	0.10	6.59	2.37	7.46	0.72	17.24
	Year	**0.52**	**24.66**	**4.45**	**21.89**	**2.68**	**54.21**
2019	**Q1**	0.16	6.05	2.31	5.13	1.39	15.03
	Q2	0.10	5.65	0.78	5.58	1.52	13.64
	Q3	0.05	3.84	2.10	2.25	0.53	8.77
	Q4	0.03	4.62	1.59	2.28	1.29	9.81
	Year	**0.34**	**20.15**	**6.78**	**15.25**	**4.73**	**47.25**
2020	**Q1**	0.09	4.13	1.14	2.57	0.85	8.77
	Q2	0.04	3.65	0.15	1.26	0.61	5.70
	Q3	0.09	3.58	0.80	0.11	0.19	4.76

Forward market trading activity for Alberta power remained low in Q3, with total volumes for the quarter below 4.8 TWh (does not include direct bilateral trades). The total volumes traded in Q3

[27] Other includes multi-year, multi-month, balance-of-year, and balance-of-month trades.

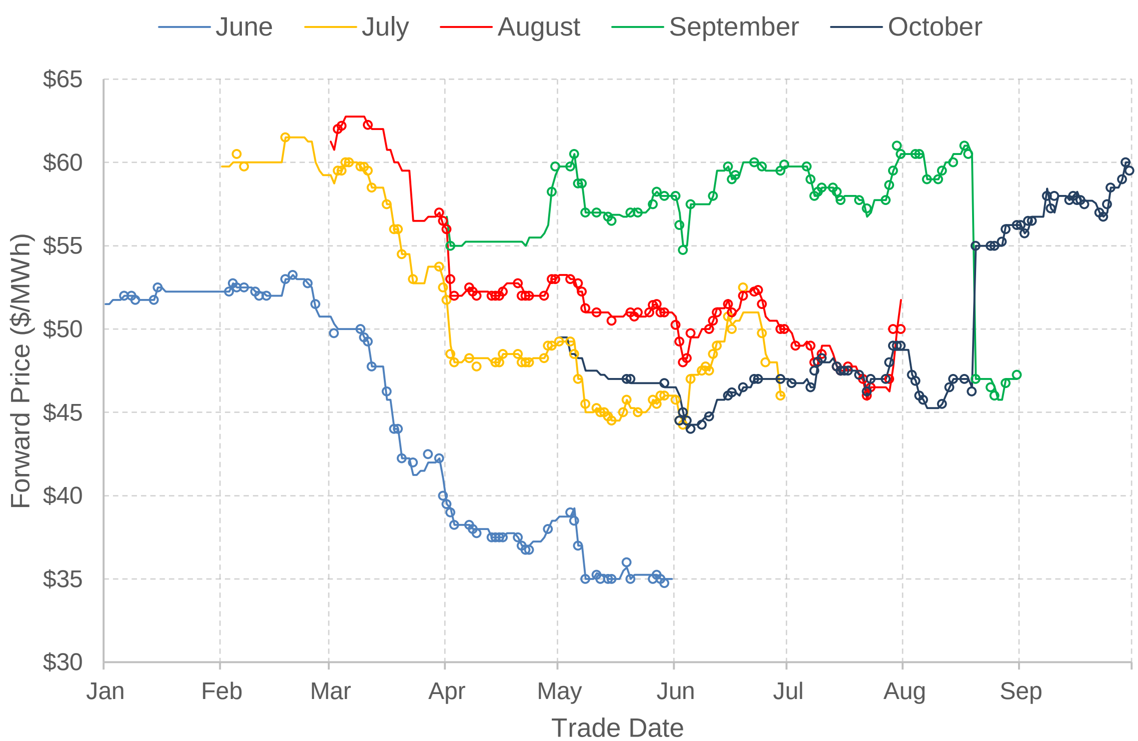
2020 were just over half of the total volumes traded in Q3 2019, which itself was a low volume quarter by historical standards. The trading activity of annual contracts was particularly low in Q3 2020 with only two trades for CAL21.

3.1 Trading of monthly products

Figure 22 shows forward prices for the June to October flat contracts five months prior to the contract start date. The vast majority of trading for monthly contracts occurs within this time frame. As discussed in the MSA's Q2 report, the forward price of July fell materially in March and early April as the first case of COVID-19 was confirmed in Alberta and oil prices declined. In early April, the forward price for July fell below, and remained below, the month's settled price of $54.14/MWh.

The forward price of the August contract was similarly affected by developments in March and April, falling from $62.00/MWh at the beginning of March to $52.00/MWh in early April. However, even at its lowest price of $45.50/MWh, the August contract was still above the August realized pool price of $41.05/MWh.

Figure 22: Forward prices for monthly flat contracts (June to October, 2020)[28]



The forward price of the September contract traded at relatively high prices for much of the year because of transmission work scheduled for September 14 to October 2; this work was scheduled

[28] The lines depict daily NGX settlement price; the markers show daily final trade price.

to remove the BC/MATL intertie from the market for approximately 19 days. As shown by Figure 22, the September flat contract generally traded between $57.00/MWh and $61.00/MWh over the summer. On the morning of August 20, the transmission work was rescheduled to run from mid to late October instead. As a result, the price of the September flat contract promptly fell from $60.50/MWh to $47.00/MWh (a 22% decline) day-over-day. After August 20, forward prices for September continued to trade in the high $40s, well above the month's realized average pool price of $36.05/MWh.

The introduction of the intertie transmission work into October inevitably increased the forward price for that month, which had been trading at $46.25/MWh on August 19. As of market close on August 20 the October contract was valued at $55.00/MWh (a daily increase of 19%), and the price continued to increase into September, with a final trade price of $59.50/MWh on September 30.

Figure 23: Monthly flat forward prices and pool prices (January to September 2020)

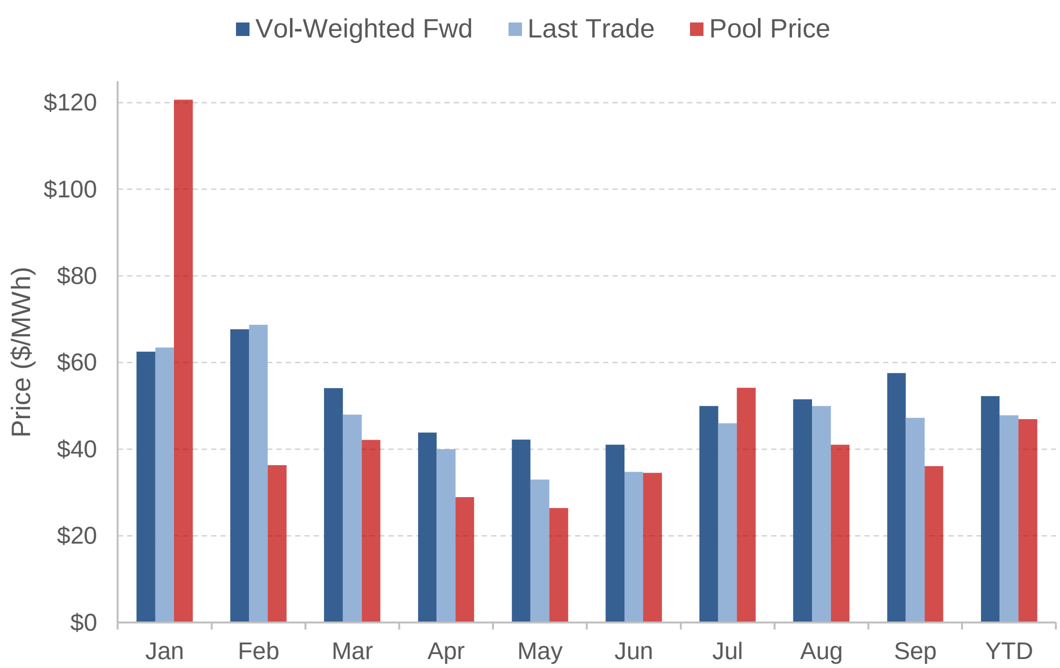
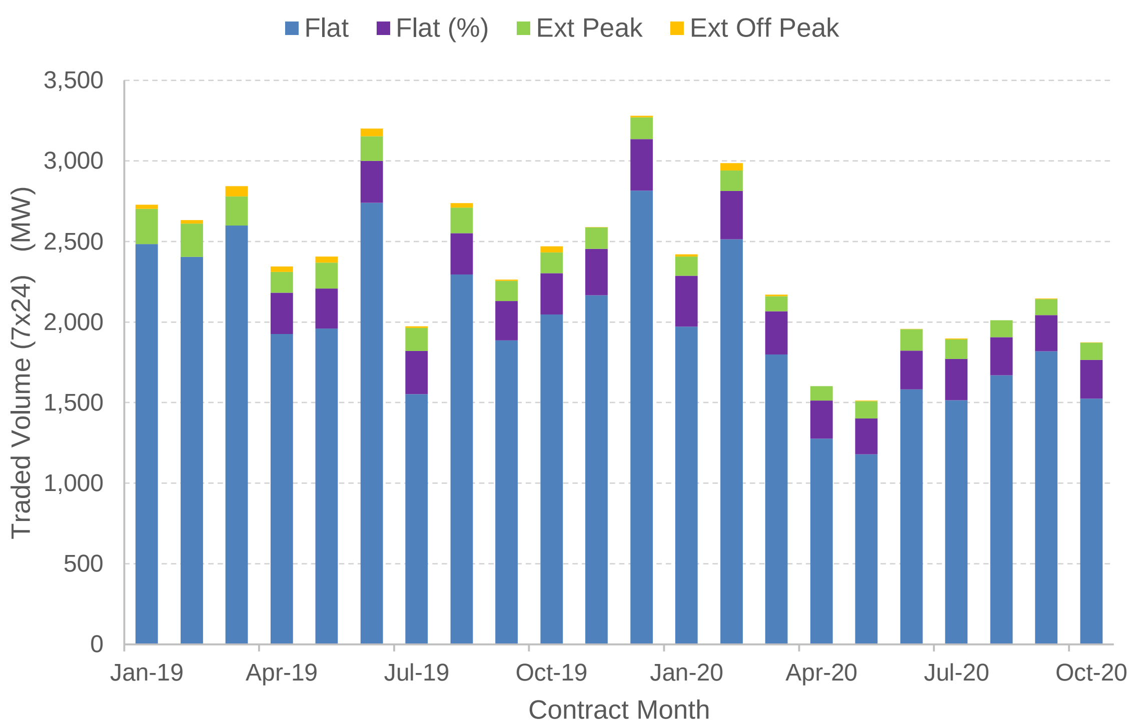


Figure 23 compares the forward prices to realized pool prices for the monthly contracts of January through September. As discussed above, the pool price for July was slightly above forward prices, but pool prices for August and September were below prevailing forward prices. Overall, the prices of flat monthly contracts in the forward market have traded at a premium of $5.30/MWh to realized pool prices for January through September (comparing volume-weighted average forward prices with realized pool prices).

The low levels of trading activity for monthly contracts continued in the quarter. Figure 24 illustrates the traded volumes for flat, full-load (flat (%)), extended peak, and extended off-peak trades by contract month since January 2019. Volumes for full-load have been estimated using an expected traded volume of 4 MW and the extended peak and off-peak volumes have been weighted by the number of hours for which they apply (16/24 and 8/24). Year-over-year, the resulting traded volumes for August and October are down 27% and 24%, respectively, while volumes for July and September were down 4% and 6%, respectively. Trading activity for September 2020 was likely increased by the fact that the BC/MATL transmission outage was initially scheduled to occur within the month, and, as discussed earlier, was subsequently moved into October.

Figure 24: Traded volumes for monthly contracts (January 2019 to October 2020)



3.2 Trading of annual products

Figure 25 shows how the Calendar 2021 (CAL21) flat contract has traded over the course of 2020. As shown, the contract started the year by increasing in price from $55.25/MWh on January 2 to $57.00/MWh at the end of January. Over the course of March through May, the price of the CAL21 flat contract fell by 10.5% to a traded low of $51.00/MWh on June 18. For the majority of Q3 the settlement price was relatively stable around $51.00/MWh despite a steady increase in natural gas prices for 2021, from $2.23/GJ on July 1 to $2.73/GJ on September 30.[29]

The settlement price of CAL21 increased by almost $0.70/MWh around the end of September and a further $1.81/MWh between October 1 and 16. The price increased a further $1.33/MWh between October 19 and 21, and the contract was valued at $55.50/MWh as of November 2.

[29] NGX Phys, FP (CA/GJ), AB-NIT, Monthly Settlement Prices

The bars in Figure 25 show the daily amount of traded volume for the CAL21 flat contract. Trading of the CAL21 flat contract was quite limited between March and mid-October. The MSA's current dataset for trading in Q3 2020 shows there were only two trades for CAL21. Trading activity for CAL21 did increase slightly around mid-October.

Figure 25: Forward prices and traded volumes for the CAL21 flat contract (January 1 to October 30, 2020)

Figure 26 shows how liquidity of the CAL21 and CAL22 flat contracts have evolved over time in comparison to the CAL20 and CAL19 flat contracts. The figure shows cumulative traded volumes beginning three years in advance of delivery for each contract. Thus, for the CAL21 contract the horizontal axis starts on January 1, 2018, and for the CAL19 contract it starts on January 1, 2016. A rise of the line depicting the cumulative traded volume indicates that a trade occurred on that day. A steeper slope of this line indicates that trading activity was relatively large while a flatter slope illustrates that trading activity was relatedly low. As shown, trading of the CAL21 flat contract has been markedly below the CAL19 and CAL20 contracts and the low traded volumes in Q3 have only exaggerated this dynamic. The traded volumes for the CAL22 flat contract are also notably low.

Figure 26: Traded volumes for flat calendar contracts (3 years prior to contract start)[30]

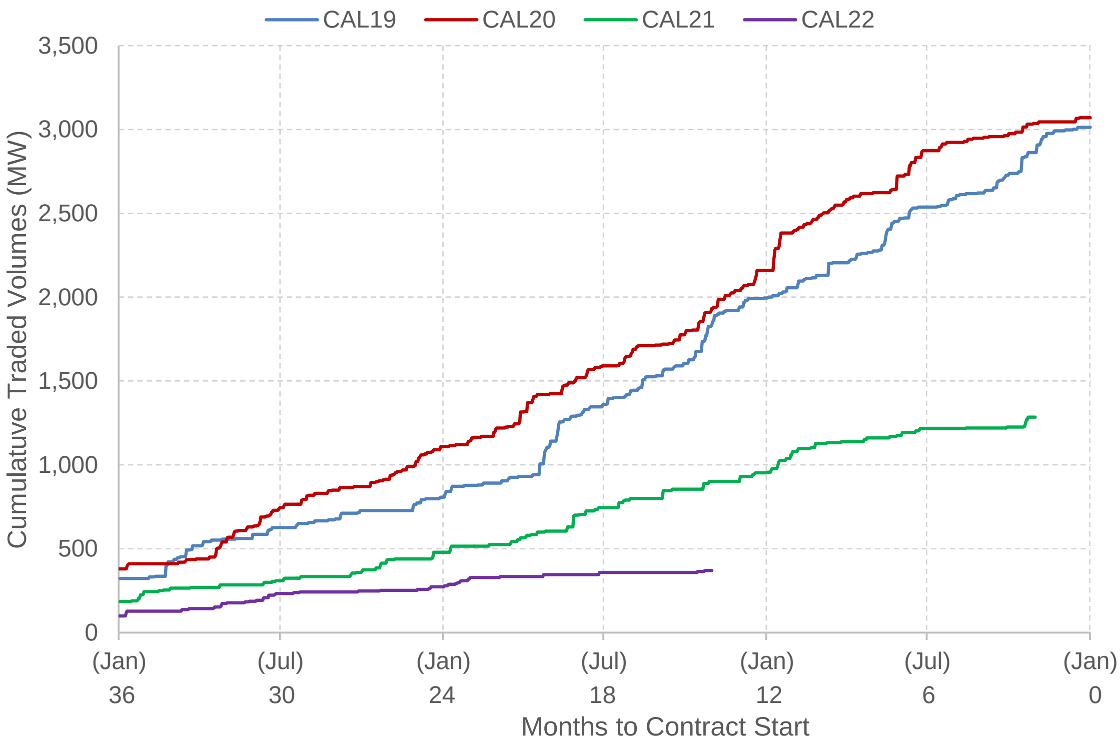


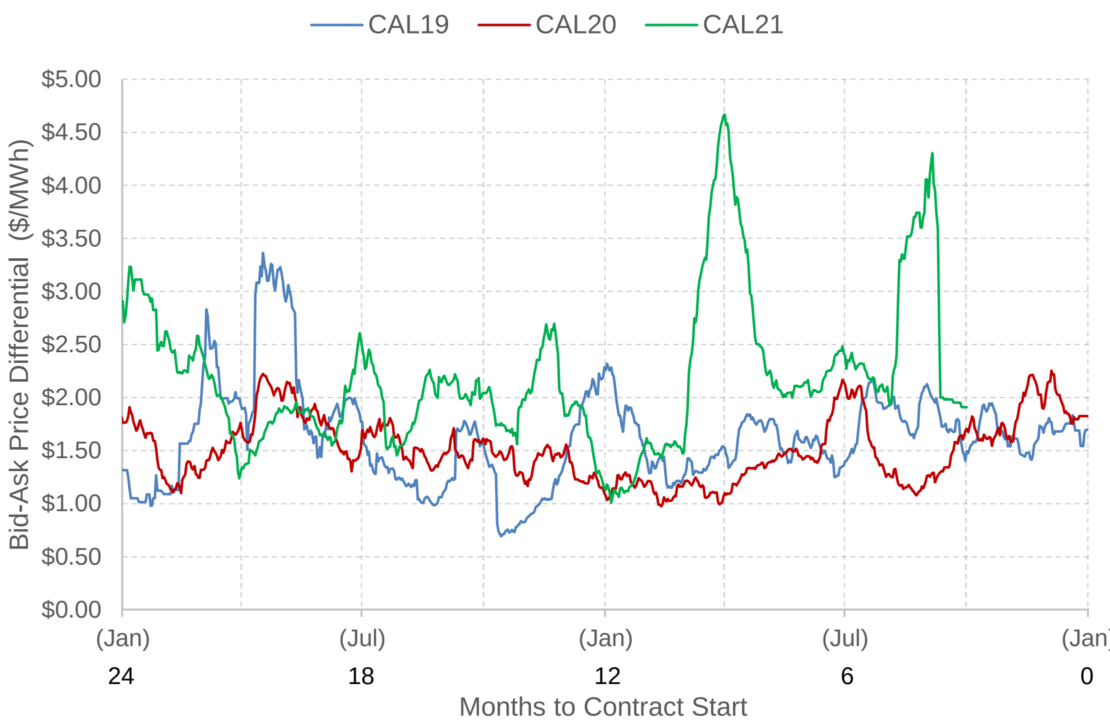
Figure 27 shows the trends in the bid-ask price differential for the CAL19, CAL20, and CAL21 flat contracts over time, beginning 2 years in advance of the contract start date. A larger price differential indicates lower market liquidity and suggests greater market uncertainty regarding pool price outcomes, as what sellers are willing to offer and what buyers are willing to bid differs more. For the period between 12 months and 3 months prior to contract start, the time-weighted average price differential for CAL21 was $2.34/MWh, higher than $1.34/MWh for CAL20, and $1.61/MWh for CAL19. For context, a $1.00/MWh difference in the price of a flat calendar contract for 5 MW (the standard traded volume) is worth approximately $44,000.

As shown, the higher average price differential for CAL21 noted above was principally caused by the price differential being significantly higher during two periods. First, the price differential began increasing in mid-March 2020, which may reflect increased uncertainty around the market implications of the COVID-19 outbreak, and may also have been influenced by traders transitioning to working from home. As shown, the 31-day centred-moving average hit a high of over $4.50/MWh at the beginning of April before decreasing. Second, in mid-August 2020 the CAL21 price differential increased again, which may have been related to pool price volatility around this time. As discussed in section 1.2.2, pool price volatility during this period was driven by warmer weather, coal plant outages, some exports to California, low wind generation on some days, and generator offer behaviour.

[30] Uses trade data from January 1, 2014 and up to and including October 30, 2020.

Outside of these two periods, the CAL21 contract has seen a slightly higher bid-ask spread compared to CAL19 and CAL20 in many periods, reflecting greater market uncertainty overall, which is discussed in the following section.

Figure 27: Bid-ask differential for flat calendar contracts, 31-day centered-moving average (2 years prior to contract start)[31]



3.3 Forward market liquidity

The forward market is an important component of Alberta's energy-only market design because it allows consumers and producers to hedge against uncertainty in the hourly pool price. In a liquid forward market, there is a high volume of trading activity which should allow participants to enter and exit traded positions quickly and at relatively low cost (in more active markets there tends to be a smaller difference between the market bid and offer prices). Higher levels of trading activity are expected to result in forward prices that reflect the expected market conditions for future periods. Increased levels of liquidity correspond to a larger number of transactions and generally more informative forward prices.

[31] Differentials show the difference between the best ask and best bid, calculated from ICE NGX data. The data ranges from 24.5 months before the delivery date, to the delivery date, except for CAL21 which includes data up to September 30, 2020. The 31 day centered moving average is the time-weighted average of differentials from 15 days before and after the date in question. The analysis only considers periods where there was a bid and an ask. For the 15 days prior to the data series ending, the 31-day centered moving average will show an average of a decreasing number of days.

The MSA's Q2 report outlined that we would reach out to forward market participants in order to more fully understand the reasons for reduced forward market liquidity.[32] Between mid-September and mid-October 2020 the MSA discussed the observed decline in trading activity for Alberta power with a variety of forward market participants, including financial traders, generators, and retailers. The general observations shared with the MSA in these discussions include:

- Following the termination of all of the thermal Power Purchase Arrangements (PPA), a government agency was an influential participant in the energy market for a number of years to present. Market participants noted that the government agency's participation in the forward market during this time has been very limited.

- Following historically low annual average pool price years in 2016 and 2017, consumers may have been incentivized to purchase more of their electricity from the spot market at pool price, rather than for a fixed-price from the forward market or through a retailer (a retailer that has a lower volume of fixed-price sales may participate less in the forward market because the retailer needs to buy less to cover these sales).

- Beginning with the April 2019 contract month some RRO volumes were purchased through full-load trades rather than flat and extended peak, which had been the case previously. Selling the full-load contract is a financial obligation based on the pool price, the traded fixed-price, and a percentage of the buyer's prevailing hourly load. The full-load contracts are arguably more risky than trading a fixed-volume contract (such as a flat), particularly for speculative traders, because higher demand can result in higher pool prices in the spot market. As a result, the seller can find themselves shorter to the pool price at the same time as pool prices are high and volatile.

- RRO auctions can generate a multiplier-effect on traded volumes in the forward market. For example, a trader might buy a flat contract with the intention of later selling it into the RRO auction for a higher price. In contrast, the full-load contracts are not actively traded on the exchange or through the broker outside of the RRO auctions at the current time, although participants can hedge the full-load contract, to some extent, through other standard contracts.

- More recently, uncertainty with regard to the impact of COVID-19 on future demand for electricity in Alberta.

- It was also noted that the current economic climate may have reduced access to credit for some forward market participants and retail consumers, and this could be a factor in reduced trading activity. In some instances, credit issues may prevent forward market participants from trading power for a fixed-price and may prevent retail customers from purchasing retail contracts. If fewer consumers are buying fixed-price power from retailers, the retailers may in-turn trade less in the forward market. On the load side, the default rate for larger consumers (over 250 MWh/year) is typically based on either gas price indices

[32] MSA Q2 2020 report, August 11 2020 (page 39)

or flow-through pool prices. For smaller consumers, the RRO rates are largely determined by forward prices for monthly contracts. On the supply side, generators would generally receive pool price in the absence of fixed-price sales.

- Lower pool price volatility in Q2 and Q3 2020 may have lowered the incentive to hedge (on both sides of the market) and potentially provided less motivation for speculative trading.

With regard to the CAL21 annual forward contract in particular, a number of specific observations were shared with the MSA about potential causes of its low traded volumes:

- Until July 2019, it was not clear whether Alberta would implement the capacity market that was previously expected to be start in November 2021.

- Following the Government of Alberta's decision in July 2019 to not implement the capacity market, the AESO was tasked with conducting a review of the price cap, price floor, and whether to introduce shortage pricing. This resulted in uncertainty about these important elements of the market design until it was decided in July 2020 that there would be no changes to the existing pricing framework.

- Uncertainty about the MSA's enforcement approach related to offer behaviour following the revocation of the Offer Behaviour Enforcement Guidelines (OBEG) in 2017.[33]

- The upcoming expiration of the Genesee, Sheerness, and Keephills coal PPAs and the Hydro PPA on December 31, 2020. For the coal PPA assets, this means the commercial management of these assets will be transferred to the respective PPA Owner(s). For the Hydro PPA, this means the financial obligations associated with the PPA will come to an end.

- A number of market participants in the Alberta electricity industry have been through the process of being purchased in the last few years.

- There is some uncertainty surrounding mothballed generation capacity, particularly if forward prices for CAL21 were to rise meaningfully.

- The impacts of COVID-19 on the Alberta economy and the provincial demand for power in CAL21 (and beyond) are uncertain.

In summary, market participants indicated that the liquidity decline in the forward market for Alberta power likely has multiple causes. For the CAL21 contract there has been, and remains, substantial uncertainty. In general, some of the reasons given for reduced liquidity point to why participants may have been electing not to trade, with many fewer reasons pointing to why

[33] The MSA notes that on June 29, 2020 it released an Enforcement Statement that sets out its ongoing approach to economic withholding in the Alberta electricity market.

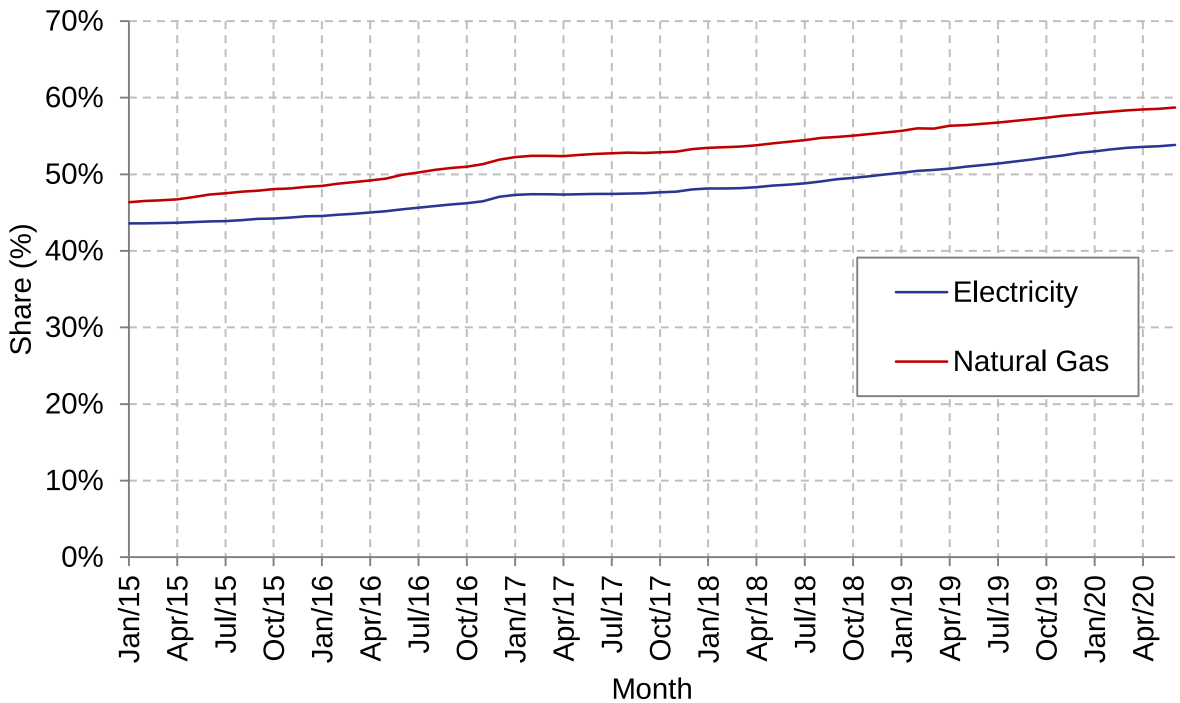
participants may have been unable to trade. Therefore, trading for CAL21 has arguably been quite limited because, broadly speaking, generators may have often chosen not to sell, consumers may have often chosen not to buy, and speculative traders may have often chosen not to take a position on the contract at prevailing forward prices.

4 THE RETAIL MARKETS

4.1 Competitive market shares

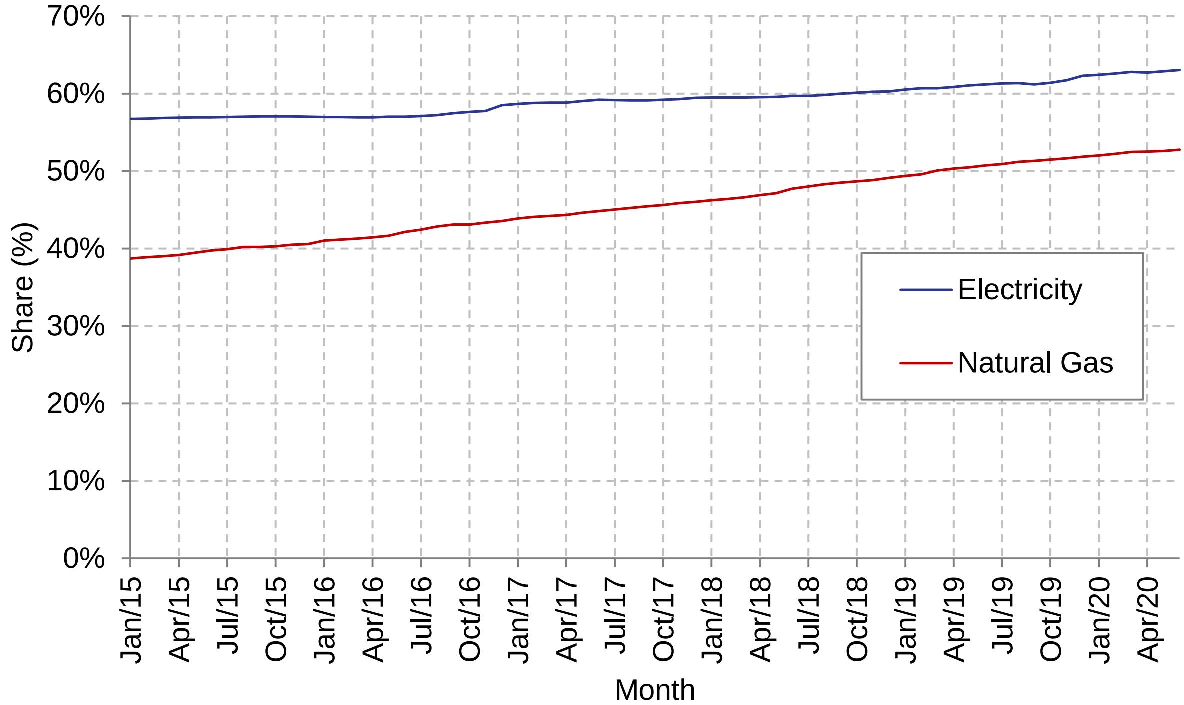
The rate of residential customers switching to competitive retail electricity and natural gas contracts slowed but remained positive over Q2/2020 (Figure 28). Competitive market shares for both contracts typically trend together owing to the popularity of dual-fuel contracts among residential customers.

Figure 28: Share of residential customers on competitive retail contracts, January 2015 to June 2020



Greater shares of commercial customers are on competitive electricity contracts compared with residential customers, but fewer have switched to competitive natural gas providers (Figure 29).

Figure 29: Share of commercial customers on competitive retail contracts, January 2015 to June 2020



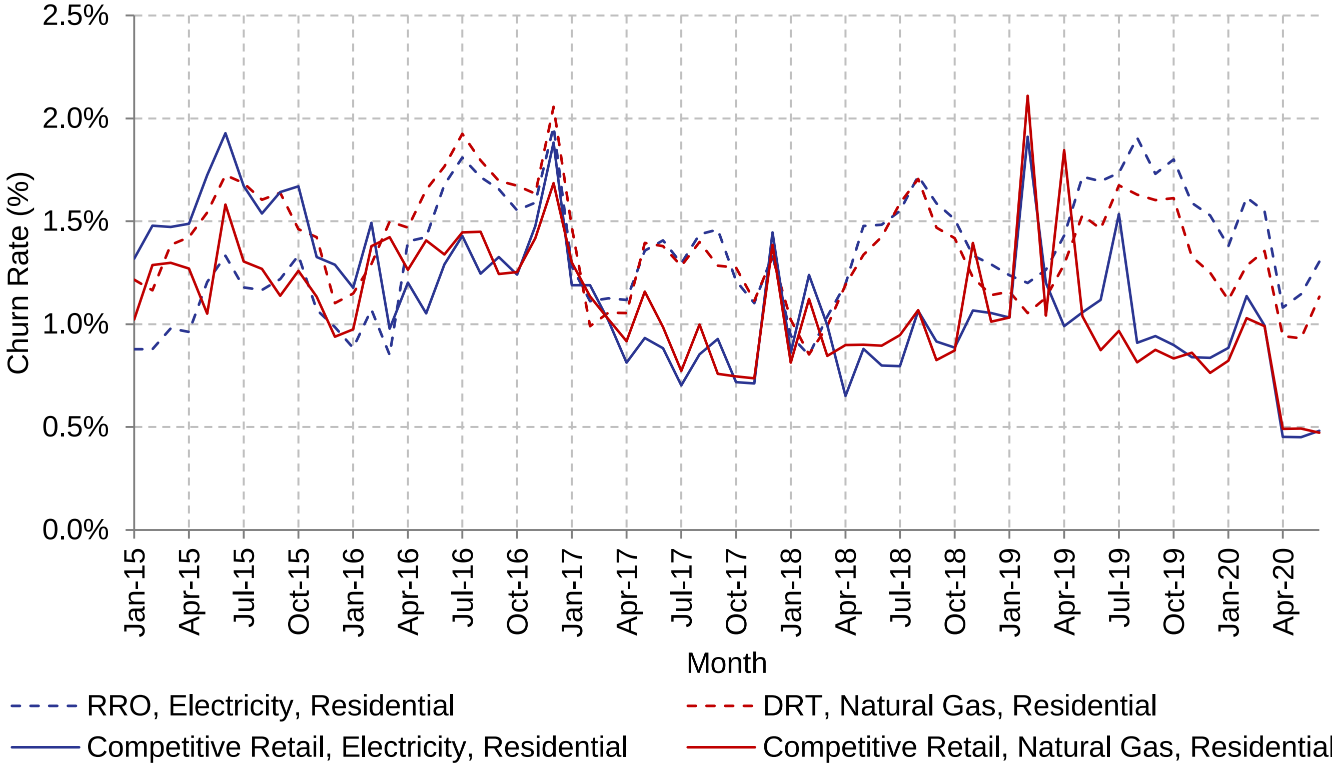
4.2 Churn

Churn rates show how frequently customers switch retailers, expressed as a percentage of retailers' existing customers. High churn rates can indicate a healthy retail market where retailers can more effectively compete for customers.

Churn rates typically range between 1 to 2% per month, and are usually greater among regulated retailers that provide Regulated Rate Option (RRO) electricity services or natural gas services under the Default Rate Tariff (DRT), indicating the share of regulated customers that leave their regulated providers for competitive retailers is greater than the share of competitive customers that leave their retailer.

Churn rates fell significantly in Q2/2020, most notably among competitive retailers (Figure 30). Fewer customers may have switched retailers over this period as a result of the COVID-19 pandemic and the associated utility cost deferral program introduced by the Alberta Government.

Figure 30: Retail churn rates, residential customers, January 2015 to June 2020



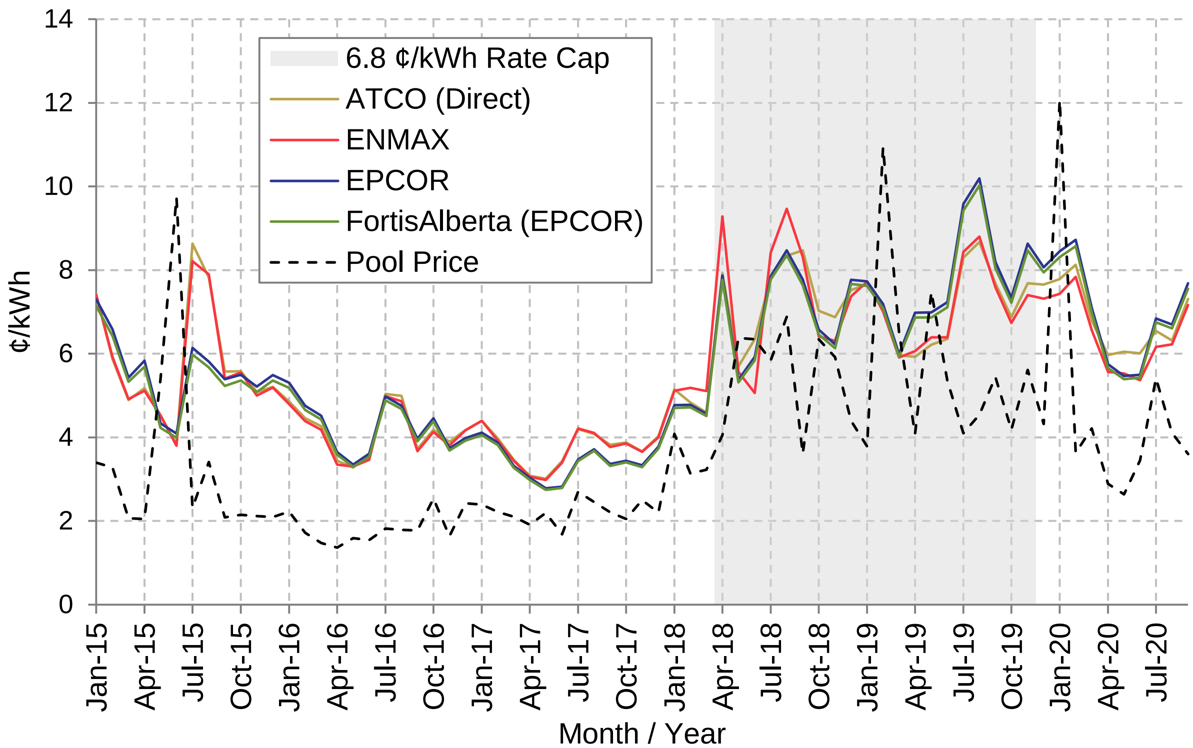
4.3 Regulated retail market

Albertans who do not choose a competitive retailer are served by a regulated electricity or natural gas retailer. The RRO is the regulated electric energy rate provided by the regulated retailer in the customer's electricity distribution service area. The DRT is the regulated natural gas rate, which varies by gas service area. Regulated rates are set by regulated retailers and approved by the Alberta Utilities Commission (AUC).

4.3.1 Regulated Rate Option (RRO)

Residential RRO rates averaged 6.82 cents/kWh in the four largest distribution service areas in Q3/2020, a 1 cent/kWh increase compared to the previous quarter (Figure 31). This increase was a result of higher forward prices for Q3/2020 monthly products compared with Q2/2020 forward prices. Forward prices for summer delivery months are typically higher than in other months, reflecting the expectation of high summer demand on wholesale electricity prices.

Figure 31: (Uncapped) Residential RRO rates, January 2015 to September 2020[34]

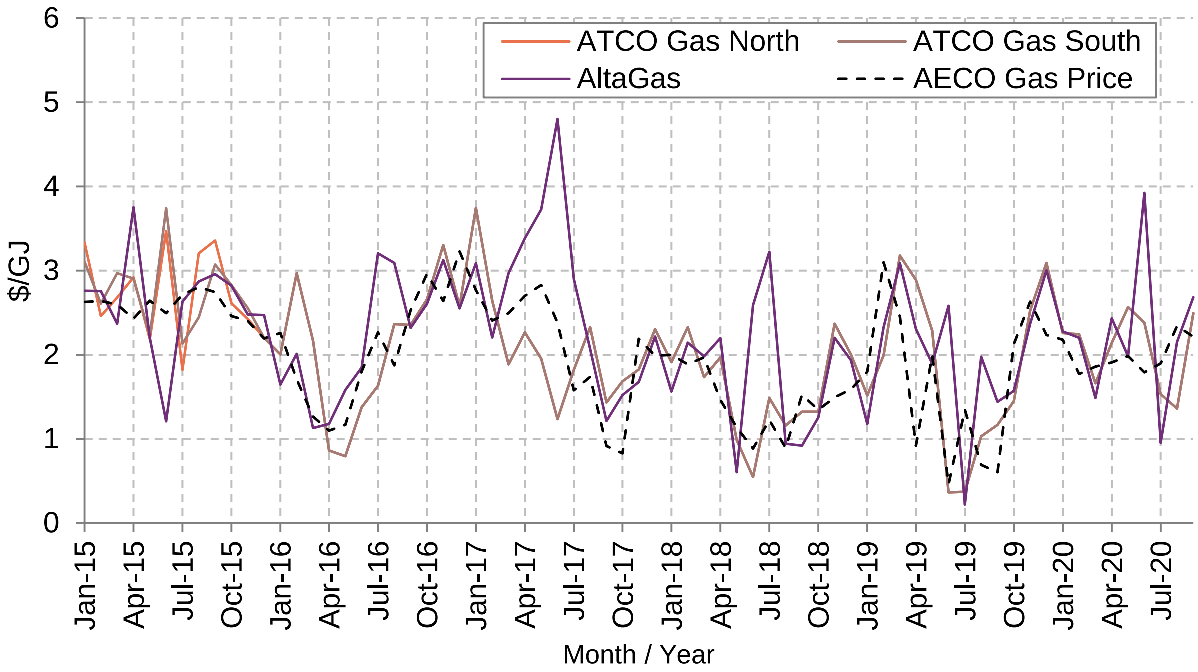


4.3.2 Default Rate Tariff (DRT)

Average DRT rates decreased to $1.84/GJ in Q3/2020, down from $2.50/GJ the previous quarter (Figure 32). Wholesale natural gas prices have averaged $2/GJ since the beginning of 2020, and are comparable to recent years.

[34] Between June 2017 and November 2019, RRO rates were capped at 6.8 ¢/kWh, with the rate cap first binding in April 2018.

Figure 32: DRT Rates, January 2015 to September 2020



5 ENFORCEMENT MATTERS

5.1 Balancing Pool investigation

On September 2, 2020 the MSA provided public notice that it had initiated an investigation under section 42(1)(b) of the *Alberta Utilities Commission Act*. The investigation focuses on the Balancing Pool's conduct in relation to potential breaches of the *Electric Utilities Act*, including sections 6 and 85, the *Fair, Efficient and Open Competition Regulation* ("FEOC Regulation"), and the Settlement Agreement between the MSA and Balancing Pool that was approved by the Alberta Utilities Commission on January 14, 2020.[35] The investigation continues at the time.

5.2 Mothball outages

The AESO has begun public consultations regarding potential amendments to ISO rule 306.7, *Mothball Outage Reporting* (the "Mothball Rule").[36] The MSA has submitted its intent to participate in this process to the AESO. In the interim before any rule changes are approved, the MSA intends to review all significant future attestations made under section 4(1) of the Mothball Rule.

To facilitate the MSA's review of mothball outage notifications, the MSA will request that market participants provide the forecast revenue and cost data on which the attestation is based. This information should be assembled at the time of providing a notification of a mothball outage to the AESO and will be formally requested by the MSA, under section 46(1) of the *Alberta Utilities Commission Act,* after notification is received. A list of information the MSA may require is provided below. The requirements for a corporate officer attestation supporting a mothball notification are outlined in section 4(1) of the Mothball Rule:

> **4(1)** A **pool participant** must, if a notification is provided to the **ISO** pursuant to subsections 3(1), or 3(3)(a) where such notification results in an extension to the duration or increase in MW of the **mothball outage** originally submitted pursuant to subsection 3(1), provide an attestation to the **ISO** from a corporate officer of the **pool participant** of the **source asset** that:
>
> (a) based on its reasonable assessment of forecast market prices and market conditions at the time the attestation is provided, such forecast market prices and market conditions are insufficient to recover avoidable costs for the **source asset** for the duration of the **mothball outage**; and

[35] Notice re: MSA has issued a formal notice of investigation to the Balancing Pool related to offer strategies undertaken at PPA units

[36] Letter of Notice regarding Potential Amendments to the Mothball Rule

> (b) the **mothball outage** will be cancelled if, based on its reasonable assessment of forecast market prices and market conditions, such forecast market prices and market conditions become sufficient to recover avoidable costs for the **source asset** for the remaining duration of the **mothball outage**.[37]

An MSA information request to a market participant notifying the AESO of a mothball outage will require the market participant to provide records supporting the forecast market prices and avoidable costs relied on in the attestation. This may include, data, analysis, engineering studies, and decision documents supporting the attestation.

The MSA may request information of the nature listed below. For greater clarity, the MSA will not request that additional analysis be conducted by the market participant.

- Forward price forecasts supporting the attestation that cover the period of the mothball outage.
- Forward price forecasts used by the market participant for purposes other than the attestation that cover the period of the mothball outage.[38]
- Records considering the merits of using one or more forecasts.
- Records considering the reasonableness of assumptions around forward price forecasts, including sensitivity analysis or examination of forecasts under different scenarios.
- Records considering the impact of other market conditions on forecast prices.
- Records considering capacity factor and realized price expectations for the mothball outage asset.
- Records that provide a breakdown of all costs avoided by the mothball outage.
- Records that provide reasons why a particular cost is considered avoidable.
- Engineering or operational assessments that detail costs that would be incurred only as a result of the mothball outage.
- Engineering or operational assessments that detail costs that would be incurred and when they would be expected to be incurred following the end of the mothball outage.

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[37] ISO rule 306.7, *Mothball Outage Reporting*.

[38] This may include forecasts prepared for the purpose of scenario analysis, Board of Director projections, and asset impairment testing.

- For any mothball outage in excess of six months, any engineering or operational assessment that indicates the likelihood the unit would be able to return to service following the mothball outage.

- Engineering or operational assessments that detail the costs and time required if a unit is required to return to service prior to the end of the mothball period.

- Where costs are expected to be delayed but not avoided by the mothball outage, records that detail the timing and magnitude of costs if the unit is assumed to continue operations (without mothball) and the timing and magnitude of those costs if the mothball occurs.

- Records that set out the discount rate, if any, and the rationale for the selected discount rate used in the assessment of costs related to the mothballing decision.

- Records that consider whether the forecast market prices and conditions are insufficient to recover avoidable costs for the source asset for the duration of the mothball outage.

Should a market participant planning a mothball outage have questions about the records that may be requested, or believe that an alternative approach would provide the records the MSA requires to conduct its assessment, it should contact the MSA at enforcement@albertamsa.ca.

5.3 ISO rule 203.6

On January 16, 2020, the MSA proposed amendment to ISO rule 203.6, *Available Transfer Capability and Transfer Path Management*, to eliminate some of the requirements made on market participants regarding imports and exports of electricity in Alberta. In its proposal the MSA noted that contraventions of this rule between 2010 and 2018 had resulted in $892,000 of specified penalties, some of which it believes could have been avoided with an amended rule. In 2019, contraventions of this rule accounted for an additional $68,750 of specified penalties.

On August 27, 2020, the AESO responded to the MSA's proposal indicating it would not be completing its review of the MSA's proposal or making any of the proposed changes to ISO rule 203.6 at this time.[39]

[39] AESO response to MSA rule amendment proposal dated January 16, 2020

6 MSA FINAL REVIEW OF RATE CAP DEFERRAL ACCOUNTS

6.1 Background

Regulated Rate Option (RRO) energy rates were capped at 6.8 cents/kWh between June 2018 and November 2019 under the Rate Cap Program. Deferral accounts with the Government of Alberta (GOA) were established to facilitate the reimbursement of RRO providers for forgone revenues resulting from the rate cap. The Alberta Utilities Commission (Commission) approved deferral accounts for the three RRO providers serving Commission-regulated distribution service areas. The MSA approved deferral accounts for fifteen RRO providers serving 38 rural electrification associations (REAs) and wire-owning municipalities.

RRO providers submitted monthly deferral account statements (DASs) to the MSA to apply for reimbursement from the GOA between April 2018 and November 2019. These DASs included the RRO provider's monthly rates[40], forecast consumption and the reference rate set by the Commission. Subsequent DASs were submitted to true-up deferral accounts for actual consumption.[41] Prior to the MSA's final review, the MSA had approved $13.1 million in deferral account compensation.

The MSA was required to complete a final review and disposition of deferral accounts (Final Review) for the fifteen RRO providers in accordance with section 8 of the *Rate Cap (Board or Council Approved Regulated Rate Tariffs) Regulation (AR 139/2017)* (Rate Cap Regulation) and the *Rate Cap (City of Medicine Hat) Regulation (AR 256/2017)* (Medicine Hat Rate Cap Regulation). Applications for the Final Review were required under section 8(1) of the Rate Cap Regulation to be submitted within six months of November 30, 2019, the date on which the Rate Cap Program ceased to apply. To facilitate the process the MSA informed RRO providers that it would deem a response to an Information Request (IR) from the MSA by May 30, 2020 (6 months after November 30, 2019) as an application for Final Review.

6.2 Process

The purpose of the MSA's final review was to confirm the information and amounts set out in deferral account statements and determine if amounts remained owing to RRO providers or if they had been overpaid under the Rate Cap Program in accordance with section 8(2) of the Rate Cap Regulation.[42]

The Rate Cap Regulation is not prescriptive of the process to be followed in a Final Review. The approach adopted by the MSA was to conduct five tests (Table 8), based on data at the MSA's

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[40] 'Monthly rates' are the RRO provider's RRO energy rates set according to the provider's energy price setting plan without accounting for impacts of the 6.8 cents/kWh rate cap.

[41] 'Actual consumption' refers to consumption of RRO customers determined through final load settlement calculations.

[42] Unless otherwise noted, the 'Rate Cap Regulation' is used interchangeably with the 'Medicine Hat Rate Cap Regulation'.

disposal, information received in the response to the MSA's IR to RRO providers, and information received from the Commission and the GOA in response to MSA requests.

Table 8: Final review tests

Test	Element tested	Description of test
1	Test of accuracy for monthly rates	Monthly rates submitted in deferral account statements are equal to RRO rates calculated in accordance with the owner's Board or Council-approved energy price setting plan(s).
2	Test of supportability for monthly rates[43]	Monthly rates are compliant with the *Regulated Rate Option Regulation* and the Rate Cap Regulation.
3	Test of accuracy for consumption amounts	Actual consumption data submitted in deferral account statements is equal to the owner's monthly RRO consumption calculated using AESO data.
4	Test of accuracy for reference rates	Reference rates submitted in deferral account statements equal the reference rates set by the Commission.
5	Test of accuracy for deferral account compensation	No outstanding deferral account payments previously approved by the MSA are owed to or owed by the owner.

The results of these five tests were brought to the MSA's internal Enforcement Committee for consideration (Committee). The Committee considered the results of these tests over the course of meetings from June through August 2020. Passing all five tests would result in a finding of no amount owed to or owing by the RRO provider. Failure of one or more tests triggered more detailed review by the Committee which in turn could result in adjustments to the deferral account information which in turn resulted in a finding that an amount had been over or under paid. In some cases the failure of a test did not result in a material adjustment to the deferral account information. While adjustments to deferral account information could result in the repayment of amounts previously received, there were no penalties imposed for findings that indicated non-compliance with regulation. In a few cases, there was insufficient information provided to conduct a test, which triggered further consideration by the Committee. In the case of the City of Medicine Hat some tests were not applicable.

On September 8, 2020 the MSA completed its Final Review and provided its determinations to the fifteen RRO providers and the GOA. In accordance with section 8(4) and 8(5), the amounts

[43] Not conducted for the City of Medicine Hat deferral accounts.

found owing to or owed by RRO providers were required to be paid within 30 days of the MSA's determination.

6.3 Findings of the tests

To complete Test 1, the MSA compared monthly rates submitted in DASs with the monthly rates calculated in accordance with the RRO provider's Board or Council-approved EPSP, to ensure their equivalence. The MSA found that a number of RRO providers had submitted monthly rates in DASs that differed from the monthly rates calculated using their energy price setting plans in some months; the majority of these differences were of limited magnitude. In these instances, monthly rates were adjusted for deferral account purposes to align with the rates calculated using EPSPs.

To complete Test 2, the MSA assessed RRO providers' energy price setting plans and monthly rate calculations to confirm the monthly rates submitted in DASs were compliant with the *Regulated Rate Option Regulation (AR 262/2005)* (RRO Regulation) and the Rate Cap Regulation. Some RRO providers did not pass Test 2 in all months. In some instances, Test 2 was failed as a result of a Test 1 failure where monthly rates were not determined in accordance with the RRO provider's energy price setting plan per section 5(4)(b)(i) of the Rate Cap Regulation. Six RRO providers failed Test 2 as their monthly rates were not compliant with at least one of the following sections of the RRO Regulation: 4(1), 5(2), 5(5), 11(1)(a)(i), 11(1)(a)(ii), 11(1)(b). Monthly rates were adjusted for deferral account purposes in instances where the non-compliance had a material impact on the value of the monthly rates.

To complete Test 3, the MSA compared the actual consumption values submitted in DASs with final settlement data obtained from the AESO's database. A close match between the final settlement and deferral account consumption data sources was sufficient to pass the test. The MSA also tested to ensure that line losses and unaccounted for energy (UFE) were not included in the consumption amounts submitted in deferral account statements. A deferral account claim on line losses and UFE was not allowed as RRO customers would not themselves be charged their allocated line losses and UFE directly in absence of the rate cap (as consumption). Adjustment factors for line losses and UFE costs are required to be included in RRO rates, pursuant to section 5(3)(d) of the RRO Regulation. Twelve RRO providers did not pass Test 3 in all months; a significant majority of these RRO providers had included line losses and UFE in the actual consumption values submitted in DASs. Actual consumption was adjusted for deferral account purposes to reflect AESO final settlement data where significant differences were found.

To complete Test 4, the MSA compared the reference rates submitted in DASs with the reference rates set by the Commission in accordance with sections 3(1) and 3(6) of the Rate Cap Regulation and sections 3(1) and 3(5) of the Medicine Hat Rate Cap Regulation to ensure their equivalence. The MSA found that in all instances reference rates submitted in DASs were equal to the rates set by the Commission.

To complete Test 5, the MSA compared the amounts paid to or received by the RRO provider to confirm their consistency with the monthly deferral account compensation previously approved by the MSA. The MSA found that in all instances the amounts previously approved by the MSA had been financially settled.

6.4 Conclusion

The MSA found that majority number of RRO providers had over-claimed on their deferral accounts, and as a result of the MSA's adjustments to the information and amounts in their deferral accounts owed as much as $46,000 to the GOA. Some RRO providers had under-claimed on their deferral accounts and were owed as much as $300,000 from the GOA. Four RRO providers were found to have neither over-claimed nor under-claimed on their deferral accounts.[44]

In total, the MSA's fifteen Final Reviews resulted in determinations netting to $157,907.94 owing to RRO providers. Including adjustments made as a result of the Final Review, the MSA has approved $13.2 million in deferral account compensation since April 2018.

[44] In the Final Reviews for two of these four RRO providers, the amounts found owed by or owing to the RRO provider were of sufficiently low value that the administrative costs of settling these amounts would exceed the value of the amounts owed or owing.

7 ISO RULES COMPLIANCE

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

From January 1 to September 30, 2020 the MSA closed 269 ISO rules compliance matters, as reported in Table 9.[45] An additional 132 matters were carried forward to the next quarter. During this period 75 matters were addressed with notices of specified penalty, totaling $128,250 in financial penalties, with details provided in Table 10.

Table 9: ISO rules compliance outcomes for matters closed from January 1 to September 30, 2020[46]

Section of ISO rules	Forbearance	Notice of specified penalty	No contravention
103.1	1	-	-
201.4	-	1	-
201.7	25	6	1
202.4	-	1	-
203.1	1	-	-
203.3	35	20	2
203.4	43	10	8
203.6	10	2	-
204.3	1	-	-
205.3	4	6	-
205.4	25	-	-
205.5	4	7	1
205.6	3	13	-
303.1	2	-	-
304.9	10	-	-
306.4	1	2	-
306.5	1	6	-
306.7	-	-	1
501.10	1	-	-
502.1	1	-	-

[45] An ISO rules compliance matter is considered to be closed once a disposition has been issued. Of the 269 closed matters, two were withdrawn.

[46] Two closed matters were withdrawn (not shown).

502.2	1	-	-
502.4	-	1	-
502.6	5	-	-
505.4	5	-	-
Total	**179**	**75**	**13**

The sections of the ISO rules listed in Table 9 and Table 10 fall into the following categories:

103	Administration
201	General (Markets)
202	Dispatching the Markets
203	Energy Market
204	Dispatch Down Service Market
205	Ancillary Services Market
303	Interties
304	Routine Operations
306	Outages and Disturbances
501	General (Facilities)
502	Technical Requirements
505	Legal Owners of Generating Facilities

Table 10: Specified penalties issued between January 1 and September 30, 2020 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)												Total ($)	Matters addressed with a penalty
	201.4	201.7	202.4	203.3	203.4	203.6	205.3	205.5	205.6	306.4	306.5	502.4		
Air Liquide Canada Inc.	500												500	1
Alberta Electric System Operator												250	250	1
Alberta Newsprint Company				1,250	5,000								6,250	2
Alberta Pacific Forest Industries Inc.					1,250								1,250	1
AltaGas Ltd.		500		1,500									2,000	2
AltaLink L.P., by its general partner, AltaLink Management Ltd.										250			250	1
Balancing Pool					2,500		500						3,000	3
Bitfury Technology Inc.							500		2,500				3,000	2
Calgary Energy Centre No. 2 Inc.				3,750									3,750	2
Canadian Natural Resources Ltd.				1,500	1,500								3,000	2
Capital Power (G3) Limited Partnership									250				250	1
City of Medicine Hat				2,500									2,500	1
Dow Chemical Canada ULC					750								750	1
Enel X Canada Ltd.									18,250				18,250	5
ENMAX Power Corporation										250			250	1
Halkirk I Wind Project LP		500											500	1
Heartland Generation Ltd.								250					250	1
Horseshoe Power GP Ltd.		500											500	1
International Paper Canada Pulp Holdings ULC					2,500								2,500	1
MEG Energy Corp.		500											500	1
Mercer Peace River Pulp Ltd.				2,500									2,500	1
Milner Power Limited Partnership by its General Partner Milner Power Inc.				12,500	5,750						500		18,750	5
NorthPoint Energy Solutions Inc.						750							750	1
Northstone Power Corp.									750				750	1
Oldman 2 Wind Farm Limited											2,000		2,000	2
Pincher Creek Limited Partnership											500		500	1
Powerex Corp.		3,250											3,250	2
Repsol Canada Energy Partnership				1,500							500		2,000	2
Riverview Limited Partnership											500		500	1

The Manitoba Hydro-Electric Board						1,500							1,500	1
TransAlta Corporation				4,000									4,000	5
TransAlta Generation Partnership			250	9,000	750		3,000	15,000	2,000				30,000	18
Voltus Energy Canada Ltd.									10,750				10,750	3
WCSB GP III Ltd.				1,500									1,500	1
Total	500	5,250	250	41,500	20,000	2,250	4,000	15,250	34,500	500	4,000	250	128,250	75

8 ALBERTA RELIABILITY STANDARDS COMPLIANCE

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

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

Effective October 21, 2020, AUC Rule 027 was amended to specify that only O&P ARS specified penalties are to be made public. CIP ARS specified penalties and information related to the nonpayment or a dispute of a CIP ARS specified penalty will not be made public. CIP matters often deal with cyber security issues and there is concern that broad public reporting creates a security risk in itself. Accordingly, at present, the MSA will continue to refrain from publishing CIP statistics.

From January 1 to September 30, 2020 the MSA closed 65 ARS O&P compliance matters, as reported in Table 11.[47] An additional 68 matters were carried forward to the next quarter. During this period, 10 matters were addressed with notices of specified penalty, totaling $25,000 in financial penalties, with details provided in Table 12.

[47] An ARS matter is considered closed once a disposition has been issued and mitigation (where applicable) is complete. Of the 65 closed matters, one matter was rejected.

Table 11: Outcomes for O&P ARS matters closed between January 1 and September 30, 2020[48]

Reliability standard	Forbearance	Notice of specified penalty	No contravention
BAL-005	2	-	-
COM-001	-	2	3
COM-002	-	-	2
EOP-001	1	-	-
EOP-005	2	-	-
EOP-008	3	-	-
INT-009	2	-	-
PRC-001	9	3	-
PRC-002	1	-	-
PRC-005	1	-	-
PRC-018	-	1	-
PRC-023	3	-	-
VAR-002	19	3	-
VAR-002-WECC	2	-	-
VAR-501-WECC	4	1	-
Total	49	10	5

Table 12: Specified penalties for matters closed between January 1 and September 30, 2020 for contraventions of O&P ARS

Market participant	Total specified penalty Amounts by ARS ($)					Total ($)	Matters addressed with a penalty
	COM-001	PRC-001	PRC-018	VAR-002	VAR-501-WECC		
Alberta Newsprint Company				2,250		2,250	1
Cancarb Limited				7,500		7,500	2
Cenovus Energy Inc.		3,750				3,750	1
EPCOR Distribution & Transmission Inc.			250			250	1
Fort Hills Energy Corporation		3,750				3,750	1
Heartland Generation Ltd.					1,500	1,500	1
Pembina NGL Corporation	2,250	3,750				6,000	3
Total	2,250	11,250	250	9,750	1,500	25,000	10

[48] One matter was rejected (not shown).

O&P ARS fall into the following categories:

BAL	Resource and Demand Balancing
COM	Communications
EOP	Emergency Preparedness and Operations
FAC	Facilities Design, Connections, and Maintenance
INT	Interchange Scheduling and Coordination
IRO	Interconnection Reliability Operations and Coordination
MOD	Modeling, Data, and Analysis
PER	Personnel Performance, Training, and Qualifications
PRC	Protection and Control
TOP	Transmission Operations
TPL	Transmission Planning
VAR	Voltage and Reactive

9 OTHER ACTIVIES

9.1 Public consultation regarding the MSA Compliance Process

The MSA Compliance Process was last revised in October 2016. Since then, new Alberta Reliability Standards (including Critical Infrastructure Protection reliability standards) and sections of the ISO rules have been adopted. Furthermore, the MSA recognizes that there may be opportunities to clarify its Compliance Process in order to reduce the regulatory burden for market participants and to help meet the MSA's red tape reduction targets.

On August 7, 2020, the MSA issued a public notice[49] indicating that it would hold a public consultation regarding its Compliance Process, beginning in September. The MSA requested preliminary feedback about areas of discussion by August 28. Six submissions were made.

Based in part on this preliminary feedback, on September 9, the MSA issued a public notice[50] requesting specific comments by September 23 on the following topics:

- self-reporting process,
- compliance monitoring and the referral process,
- forbearance criteria and specified penalties,
- conditional forbearance and contravention mitigation,
- transparency and reporting, and
- additional comments.

Comments were received from nine stakeholders.[51]

Following its review of these comments, on October 23, the MSA issued a public notice[52] that provided a revised version of the MSA Compliance Process. A public virtual stakeholder session was held on October 29 to discuss the revisions. Written comments were requested by November 12. After these comments have been received and reviewed, the MSA will make final revisions to the MSA Compliance Process. The MSA expects to conclude this consultation before the end of the year.

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[49] MSA Public Notice: Re: Compliance process consultation and MSA proposals to amend AUC Rules (August 7, 2020)

[50] MSA Public Notice: Re: MSA Compliance Process consultation (September 9, 2020)

[51] MSA Public Notice: Re: MSA Compliance Process consultation – stakeholder comments (revised) (September 25, 2020)

[52] MSA Public Notice: Re: MSA Compliance Process consultation –revised draft and request for comments (October 23, 2020)