MARKET SURVEILLANCE ADMINISTRATOR

Quarterly Report for Q2 2020

August 11, 2020

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

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THE QUARTER AT A GLANCE

- The overall price level in the Alberta market indicates the power pool was competitive in Q2 2020.

- The average pool price in the quarter was $29.90/MWh, down from $56.57/MWh in the same quarter of 2019. Pool prices exceeded $50/MWh in only a few hours during a period in June when the intertie with BC was limited in capacity. Starting in late May, and continuing on into June, supply surplus events began to occur during the lighter load hours of the day.

- There was a marked reduction in Alberta load in Q2 2020 compared to previous years; this was in large part due to the effects of COVID-19. This reduction impacted forward prices for near-term delivery. Related to this, the price of the Calendar 2021 (CAL21) contract has fallen 10% since mid-February. Forward prices for the April, May and June contracts also declined substantially prior to settlement, especially in March, but forward prices for these months traded well above realized pool prices overall. This report contains extensive analysis of forward price movements and trading volumes.

- On June 7, 2020, a frequency excursion in Alberta occurred after lightning struck the BC interconnection. Subsequently, AESO has revised upwards the amount of LSSi it will use to support high imports on the BC/MATL interconnection. In the near future, import volumes will be limited on occasion as the volume of LSSi currently contracted by AESO is insufficient to meet requirements at high levels of imports.

- The cost of operating reserves was 69% lower than the same quarter the previous year. The primary driver of the costs of active reserves is pool prices, which were down 47% year-over-year. Examples of inefficient outcomes in the reserves market were identified.

- Trading activity in the forward market has been in decline for a number of years and this pattern continued in Q2 2020. Most notable is the low volume of trading for the prompt year contract, CAL21.

- The MSA finalised a number of issue assessments / investigations: one was related to outages that occurred in January 2020 and concluded that there was no evidence of anti-competitive behaviour. A possible case of wash trading was examined but did not warrant investigation.

- The MSA published a notice in late June that sets out its enforcement stance with respect to economic withholding in the wholesale market.

- From April 1 to June 30, 2020, the MSA closed 101 ISO rules compliance matters; 34 matters were addressed with notices of specified penalty. From April 1 to June 30, 2020, the MSA closed 12 Alberta Reliability Standards Operations and Planning compliance matters; two 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 Q2 2020. Market summary statistics for the quarter are reported in Table 1.

The average pool price in the quarter was $29.90/MWh, almost 50% less than in Q2 2019 and the lowest quarterly average since Q4 2017. Pool prices were under $50/MWh in 97% of the hours in Q2 2020, and under $30/MWh in 59% of hours.

There were 2,218 minutes in which the System Marginal Price (SMP) was $0/MWh (the offer and market price floor). There were 17 periods when SMP equalled $0/MWh including 26 hours where the pool price settled at $0/MWh. When prices clear at the price floor it indicates that the market has more supply at $0/MWh than load willing to consume at $0/MWh. The Alberta Electric System Operator (AESO) must then balance the system by following a set of administrative procedures.

Table 1: Market summary

		2020	2019	*Change*
Pool Price (Avg $/MWh)	Apr	28.92	40.80	*-29%*
	May	26.39	74.78	*-65%*
	Jun	34.51	53.52	*-36%*
	Q2	**29.90**	**56.57**	***-47%***
Demand (AIL) (Avg MWh)	Apr	9,091	9,306	*-2%*
	May	8,503	9,106	*-7%*
	Jun	8,739	9,284	*-6%*
	Q2	**8,775**	**9,231**	***-5%***
Gas Price (Avg $/GJ)	Apr	1.89	0.87	*117%*
	May	1.98	1.86	*7%*
	Jun	1.79	0.48	*277%*
	Q2	**1.89**	**1.08**	***75%***
Wind (Avg MWh)	Apr	658	531	*24%*
	May	603	299	*102%*
	Jun	643	401	*61%*
	Q2	**635**	**409**	***55%***
Net Exports (Avg MWh)	Apr	-280	-208	*35%*
	May	-592	-672	*-12%*
	Jun	-592	-482	*23%*
	Q2	**-489**	**-456**	***7%***
Supply Cushion (Avg MW)	Apr	2,242	1,581	*42%*
	May	2,147	1,548	*39%*
	Jun	1,932	1,801	*7%*
	Q2	**2,108**	**1,643**	***28%***

The decline in pool prices year over year was driven by changes to both demand and supply fundamentals. On the demand side, average Alberta Internal Load (AIL) was down 4.9% year-over-year, and average AIL during peak hours was down 5.2%. The observed reduction in Alberta's total electricity demand was largely caused by the COVID-19 pandemic, which led to provincial public health measures beginning mid-March and was a major factor in the observed decline in oil prices. The lower oil prices caused some oilsands operators to reduce production, and consequently there has been a material decrease in behind-the-fence industrial demand.[1]

Natural gas prices continued to remain low, averaging less than $2/GJ over the quarter. However, this was in fact a significant recovery from last year's natural gas price, reflected in a 75% price increase.

[1] AESO: An Update on the Impact of COVID-19 and Low Oil Prices on Alberta's Power System (June 29, 2020)

In terms of supply, compared to the year-earlier period, wind generation increased 55% to an average hourly value of 635 MWh, in part due to 336 MW of wind capacity being installed since the end of Q2 2019 and higher and more uniform capacity factors. In addition, there was a slight increase in the volume of imports year-over-year, with an average of 592 MWh of imports observed in May and June. As discussed later in this report, imports were constrained for a period of time in June.

In late April, total wind generation in Alberta exceeded total generation from coal for the first time ever. This will occur more frequently in the future with continued investment in wind generation and the phase out of coal generation. On May 9, 2020, Maxim Power disconnected the existing coal-fired unit at HRM (144 MW) and replaced it with a 208 MW simple cycle gas unit.

1.2 Market outcomes

Figure 1 illustrates a scatterplot of the relationship between hourly pool price and supply cushion in Q2 2020.[2] The majority of hours in the quarter had a large supply cushion and settled at a low pool price; there were no pool prices above $50/MWh in April and May. Following the BC/MATL intertie trip on June 7, the AESO limited imports from BC/MATL to 550 MW,[3] and transmission outages around that time further limited imports from BC/MATL to less than 400 MW.[4] This matter is discussed in further detail in section 1.2.3.

Figure 2 illustrates the overall distribution of market supply cushion in the quarter. For example, just over 25% of the hours within the quarter had a supply cushion of between 2,000 MW and 2,500 MW. In addition, the figure illustrates that none of these hours observed a pool price of greater than $50/MWh. Figure 2 also shows that there were a few high-priced hours in the quarter as the supply cushion tightened in June. All pool prices in excess of $50/MWh in Q2 2020 occurred in June when the intertie was constrained (see section 1.2.3).

[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. Higher supply cushion values indicate greater generation capacity availability relative to demand. Therefore, higher values of supply cushion should generally be associated with lower pool prices, and vice versa.

[3] AESO: Reduced ATC Into Alberta (June 15, 2020)

[4] AESO: Historical Intertie Capability Report

BC Hydro Transmission Outages Annual Outage Plan

Figure 1: Hourly pool price and supply cushion (Q2 2020)

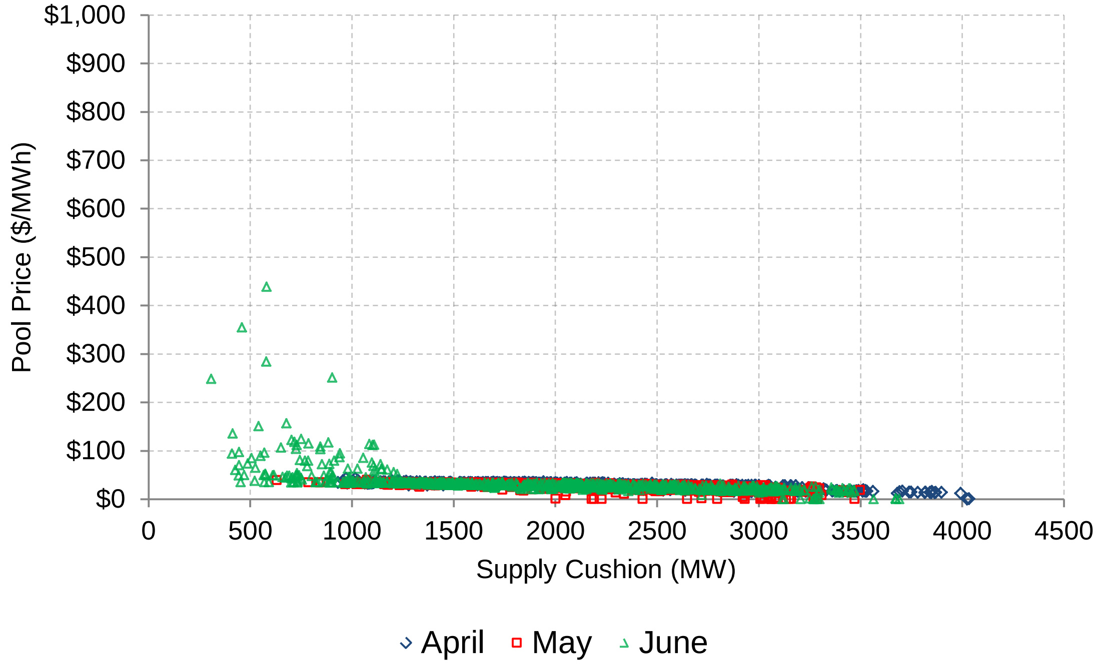


Figure 2: The distribution of hourly supply cushion in Q2 2020

1.2.1 *April 2020*

The average pool price in April 2020 was $28.92/MWh. Figure 3 shows pool prices, supply cushion, and total demand for the month. The supply cushion exceeded 1,200 MW for the vast majority of hours, indicating significant availability of supply relative to demand. Demand for electricity declined over the course of April as average temperatures increased and the effects of low oil prices and the provincial public health measures put in place to limit the spread of COVID-19 continued. On the supply-side, there were few outages in the month and the interties facilitated average hourly imports of 315 MWh in on-peak hours. As a result of these factors, the pool price did not rise above $45/MWh in April.

Figure 3: Hourly demand, supply cushion, and pool price for April 2020

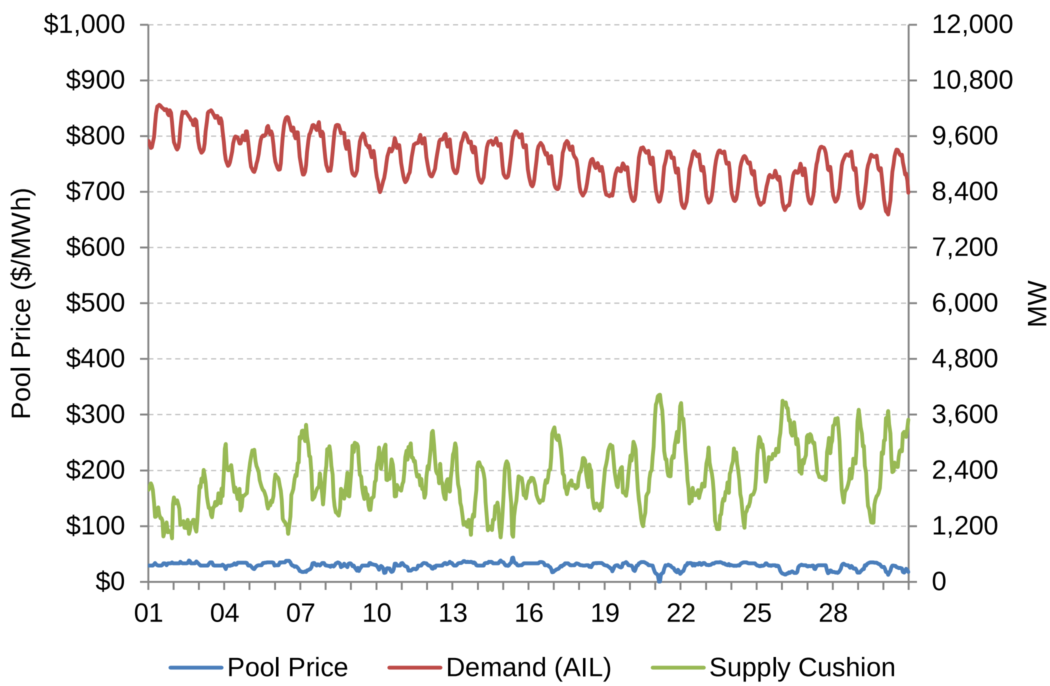


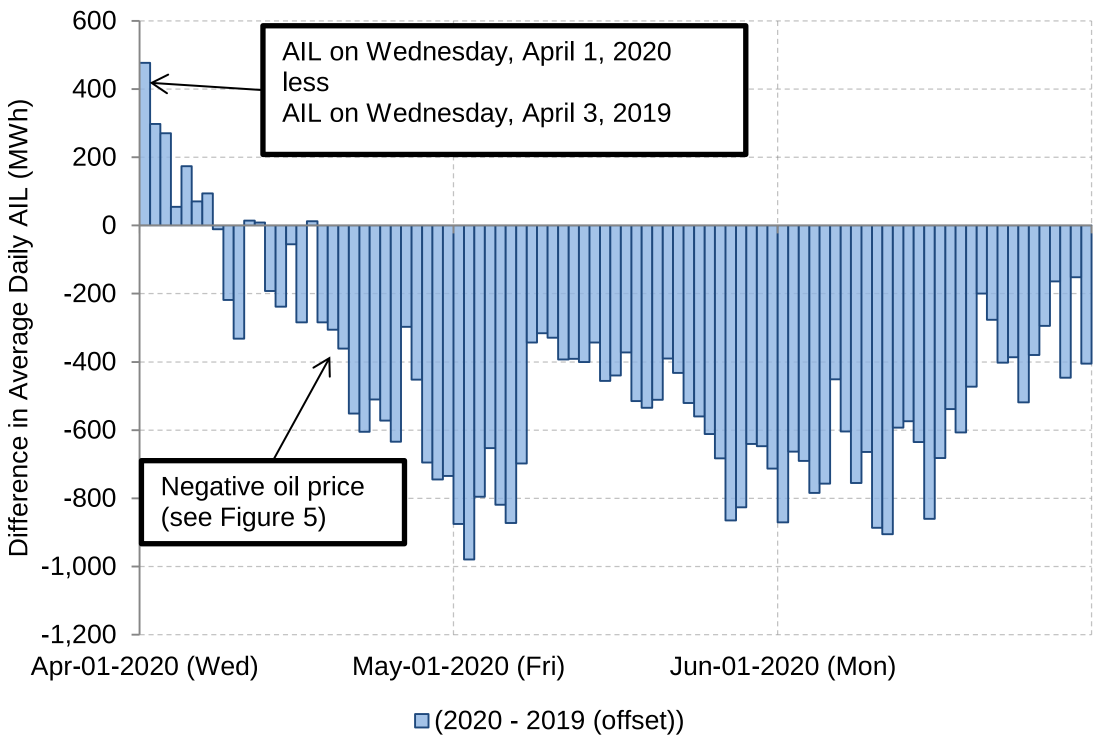
Figure 3 illustrates the declining trend in total demand over the course of April. The same trend is observed when comparing AIL year-over-year. Figure 4 illustrates the change in the average daily demand observed in Q2 2020 from the corresponding weekday last year. For example, the average demand for Wednesday, April 1, 2020 is compared to the average demand for Wednesday, April 3, 2019. This ensures that the analysis is not influenced by comparing demand for different days of the week. However, the comparison is still affected by prevailing temperatures. Table 2 shows that average temperatures were lower on average in March and April this year compared to 2019, this would tend to cause overall electricity demand to be higher in 2019 for these months due to increased heating load. Temperatures in May and June were very comparable with last year on average.

Table 2: Average temperatures (°C) in Alberta for March to June, 2020 and 2019[5]

Month	2020	2019	Difference
March	-6.74	-2.88	-3.87
April	1.55	4.77	-3.22
May	10.40	10.39	0.01
June	14.79	14.51	0.28

As shown in Figure 4, the market observed a material decline in demand over the course of April when compared to last year, and prevailing temperatures were a factor in this. Alberta typically observes a decline in total electricity consumption over the spring months, as average temperatures rise and heating load declines. However, the decline observed this year was notably larger than last year. Table 3 compares the average change in weekly demand observed over March and April this year compared with 2019. As shown, demand declined by 14.4% this year compared to 9.6% last year.

Figure 4: Change in average daily demand, 2020 compared to 2019



[5] The table uses hourly data on temperatures in Calgary, Edmonton, and Fort McMurray with each location having an equal weight in the calculation of the average figures.

Table 3: Average demand by week (March and April, 2020 and 2019)

2020			2019		
Week start	**Avg. demand (MWh)**	**Weekly change**	**Week start**	**Avg. demand (MWh)**	**Weekly change**
Mar-02-2020 (Mon)	10,082	0.2%	Mar-04-2019 (Mon)	10,377	-2.3%
Mar-09-2020 (Mon)	10,235	1.5%	Mar-11-2019 (Mon)	9,906	-4.5%
Mar-16-2020 (Mon)	9,990	-2.4%	Mar-18-2019 (Mon)	9,613	-3.0%
Mar-23-2020 (Mon)	9,744	-2.5%	Mar-25-2019 (Mon)	9,509	-1.1%
Mar-30-2020 (Mon)	9,750	0.1%	Apr-01-2019 (Mon)	9,401	-1.1%
Apr-06-2020 (Mon)	9,288	-4.7%	Apr-08-2019 (Mon)	9,342	-0.6%
Apr-13-2020 (Mon)	9,031	-2.8%	Apr-15-2019 (Mon)	9,224	-1.3%
Apr-20-2020 (Mon)	8,728	-3.4%	Apr-22-2019 (Mon)	9,233	0.1%
Apr-27-2020 (Mon)	8,626	-1.2%	Apr-29-2019 (Mon)	9,380	1.6%
Total change	**-1,456**	**-14.4%**	**Total change**	**-997**	**-9.6%**

Demand for electricity in Alberta is materially influenced by the output of Alberta's oilsands operations, as electricity is a key input into their production process. Global oil prices declined in the first quarter of 2020 (see Figure 5). On April 1, 2020, the spot price for West Texas Intermediate (WTI) settled at US$20/bbl compared to US$61/bbl on January 2, 2020, a fall of 67%.[6] In addition to the declining demand for oil resulting from the COVID-19 pandemic, in early March OPEC+ members failed to reach an agreement on proposed production cuts.[7] As a result, oil prices fell below the production costs of many Alberta oil producers, some of which announced partial shutdowns of operations until prices improve.[8]

[6] EIA Daily Data: Cushing, OK WTI Spot Price FOB

[7] Washington Post: Why the OPEC-Russia Blowup Sparked All-Out Oil Price War (March 20, 2020)

CNBC: 5 Charts that explain the Saudi Arabia - Russia oil price war so far (April 1, 2020)

[8] AESO: Impacts of the COVID-19 Pandemic and Low Oil Prices on Alberta's Power System (April 21, 2020)

Alberta Western Canadian Select oil prices averaged US$3.50/bbl in April. Government of Alberta: Oil Prices

Figure 5: WTI crude oil prices - near month futures (January 1 to June 30, 2020)[9]

On April 9 OPEC+ agreed to cut production significantly beginning in May.[10] Despite this, on Monday, April 20 WTI crude oil prices cleared at negative values for the first time (the closing price for May delivery was negative US$37.63/bbl), as oversupply combined with limited storage capacity caused prices to plummet for the May contract, which expired the next day.[11]

1.2.2 May 2020

Oil prices recovered significantly over the course of May (see Figure 5) and the Alberta government began to relax some of the provincial public health measures.[12] However, the demand for electricity remained low in May with an hourly average of 8,503 MWh, the lowest monthly average since June 2016. When compared to May last year (see Figure 4), demand was 602 MWh (6.6%) lower in May 2020.

Figure 6 illustrates pool price, supply cushion, and demand for the month of May. Outside of its normal intraday and intraweek variation, demand did not trend upwards or downwards; rather, it was relatively stable across the month.

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[9] ICE NGX Reports: Market Data, WTI/FX Report

[10] OPEC: Press Releases - Meeting of April 9, 2020

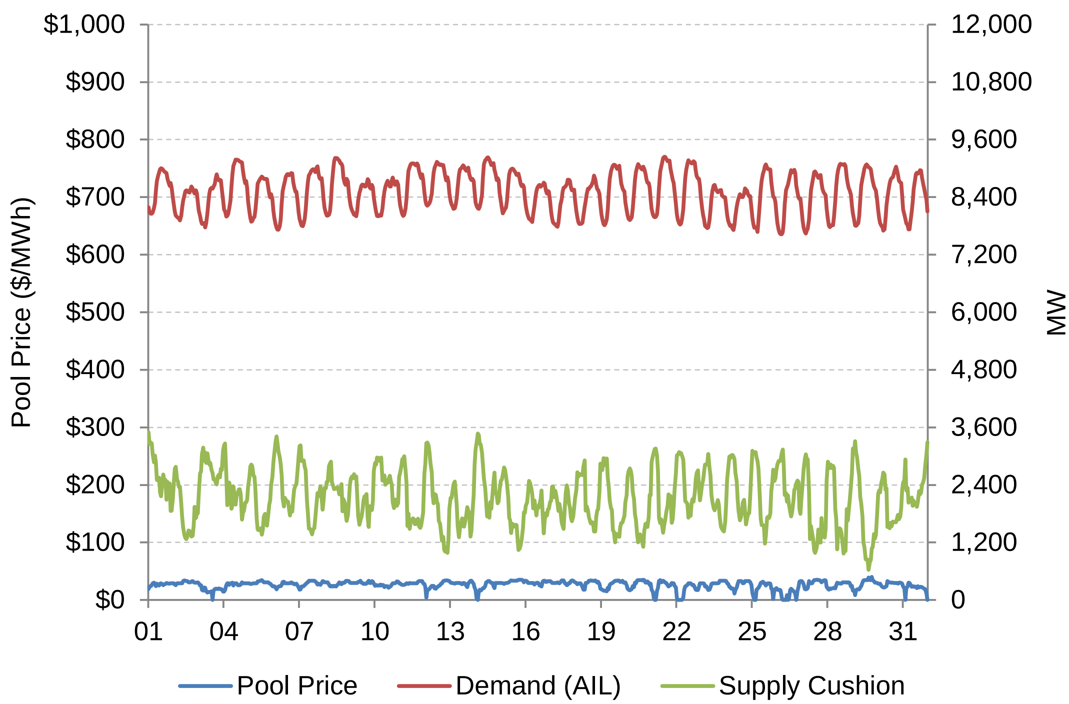
World Oil: Saudi Arabia and Russia end their oil-price war with output cut agreement (April 9, 2020)

[11] New York Times: Too Much Oil: How a Barrel Came to be worth less than nothing (April 20, 2020)

[12] Alberta Government – Stage 1 May 14, 2020

As with April, the vast majority of hours in May had a supply cushion above 1,200 MW. Pool prices in May were low, averaging $26.39/MWh, with a maximum of $39.91/MWh. In addition, there were 14 hours in May where the hourly pool price settled at $0/MWh, indicating supply surplus conditions were in effect for the entire hour. Supply surplus is discussed in more detail in section 1.3.

Figure 6: Hourly demand, supply cushion, and pool price for May 2020



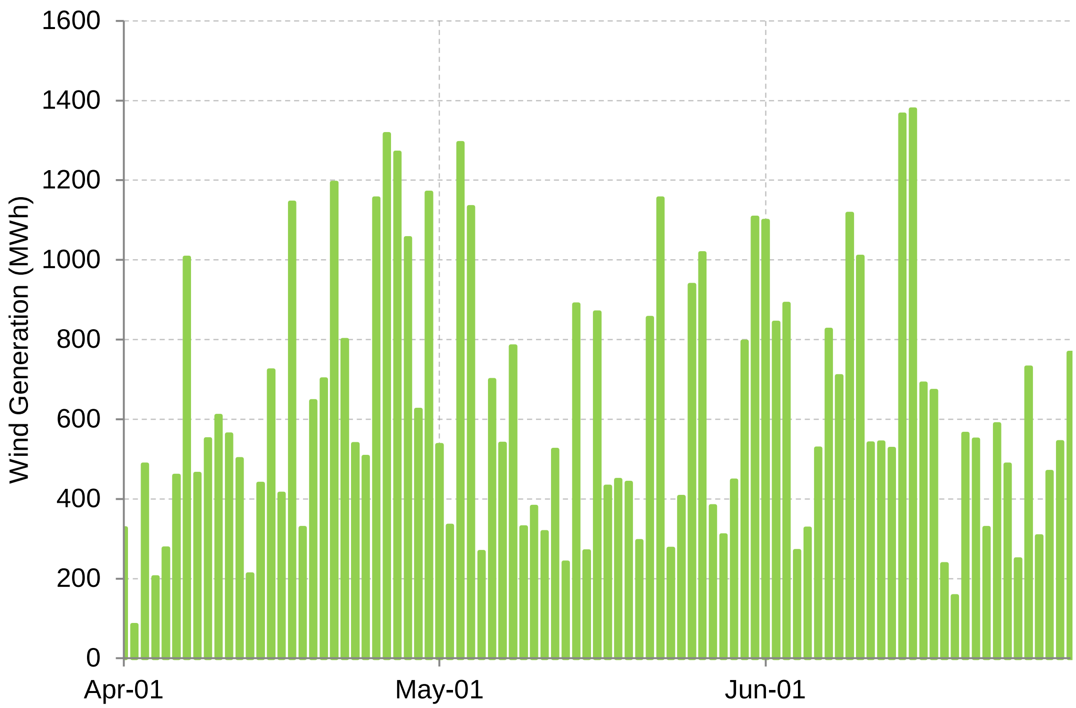
On the supply side, in May import volume averaged 603 MWh during on-peak hours. High volumes such as these are not abnormal in the spring months because water levels are elevated in the Pacific Northwest hydro region. Within Alberta, average hourly hydro generation for May was 301 MWh, 50% higher than May 2019. Pool prices for May 2020 were substantially lower than those in May 2019, which suggests that the additional hydro supply this year was due to hydrological conditions.

In addition, wind generation in May increased by greater than 100% year-over-year (see Table 1). Average wind generation for the quarter was 55% greater than in the previous year, driven upwards by some high days in late April, early May, and mid-June (see Figure 7). This year-over-year increase in wind generation is due in part to investment in 336 MW of wind capacity between Q2 2019 and Q2 2020 (an increase of 23%), as well as the capacity factor of wind generation being higher year-over-year, particularly in May (see Table 4).

Table 4: Average wind generation and capacity factor by month (Q2 2020 and 2019)

Month	2020		2019	
	MWh	**Capacity factor**	**MWh**	**Capacity factor**
April	658	37%	531	37%
May	603	34%	299	21%
June	643	36%	401	28%
Q2	**635**	**36%**	**409**	**28%**

Figure 7: Daily average wind generation Q2 2020



1.2.3 June 2020

Early in June, low demand and high volumes of imports continued resulting in low pool prices. Indeed, the month of June started off as HE24 of May 31 ended, with the pool prices for HE01 through HE06 of June 1 clearing at $0/MWh indicating supply surplus conditions. There were three additional $0/MWh hours on June 3 and two more on June 26, bringing the total number of $0/MWh pool prices for the quarter to 26 (see section 1.3 for further discussion on supply surplus).

At around 14:50 on Sunday, June 7, lightning struck the BC intertie and caused the BC and MATL interties to trip offline simultaneously. At the time, the BC/MATL intertie was flowing 923

MW of imports to Alberta. At 14:50 the AESO directed 729 MW of contingency reserves to provide power or reduce load. In terms of the energy market, the System Marginal Price (SMP) increased slightly from $28.88/MWh to $33.12/MWh around the time the interties tripped. The market observed a material decrease in demand following the BC and MATL interties tripping offline; three minutes following the trips AIL had declined by 807 MW, with no subsequent material decline in load. This decline in total demand would include the response of Load Shed Service for imports (LSSi), loads declining in response to directives, under-frequency load shed, and potentially price-responsive loads concerned about the market impacts of the event.

In part due to low system inertia and a low frequency response from online generation, this event did cause frequency issues on the Alberta transmission system, and approximately 235 MW of load was shed, plus 181 MW of LSSi.[13] The interties were restored to service a few hours later, although at a reduced capacity. The AESO subsequently announced that import flows on the BC/MATL intertie would be restricted to a maximum of 550 MW while the event was investigated.[14] Beginning in HE10 of June 8, the AESO restricted imports to 312 MW noting a transmission outage on 2L294. This transmission outage restricted flows on the BC/MATL intertie to less than 400 MW for most hours until HE16 of June 26, 2020, when the AESO declared BC/MATL available for 719 MW.[15] There is additional discussion about this matter in section 1.4.

Figure 8 illustrates the changes to the AESO's declared import Available Transfer Capability (ATC) for the BC/MATL intertie in June. The figure also plots hourly pool price, and shows that some pool prices were high when imports were restricted. While the intertie restrictions were a factor in these higher prices, other fundamentals underlie these market outcomes as well.

The total demand for electricity trended upwards over the course of June as temperatures increased and the provincial public health measures related to COVID-19 were relaxed.[16] As shown in Table 5, average demand was up by 491 MWh or 5.8% when comparing the week of June 29 with the week of June 1. However, average demand continued to track below last year's values.

[13] AESO: ATC Risk Mitigation Measures Information Session Presentation (July 28, 2020)

[14] AESO: Reduced Available Transfer Capability into Alberta (June 15, 2020)

[15] There was also a transmission outage on the BC side from June 16 to June 26 which limited the import flow on the BC intertie to 560 MW - BC Hydro: Annual Outage

[16] Alberta Government – Stage 2 June 12, 2020

Figure 8: BC/MATL import ATC (AESO), BC/MATL net imports, and pool price (June 2020)

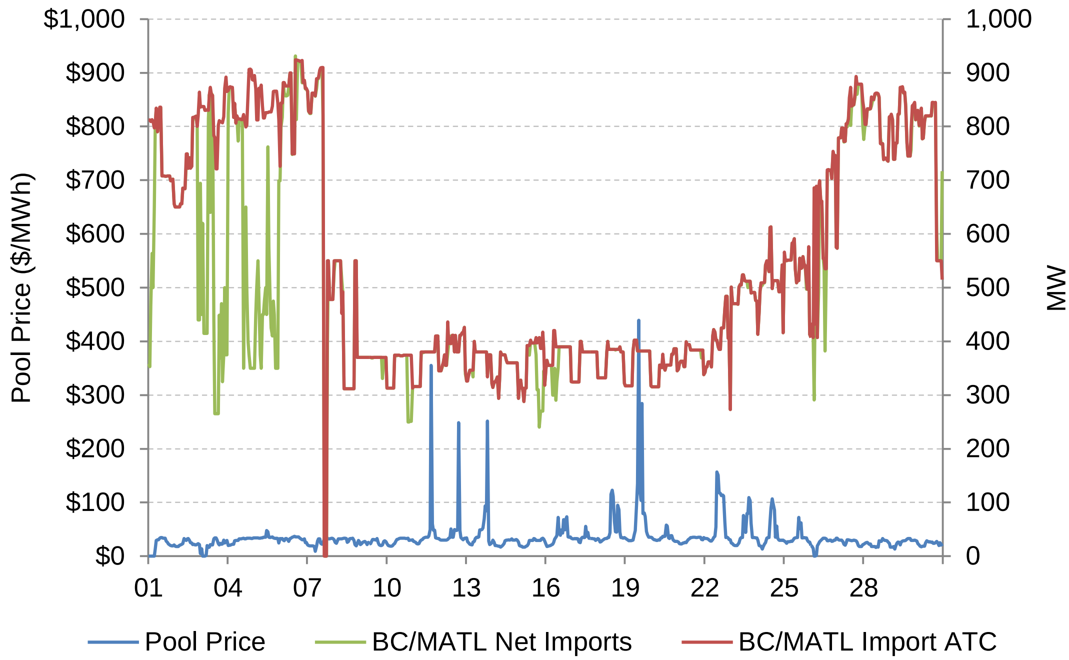


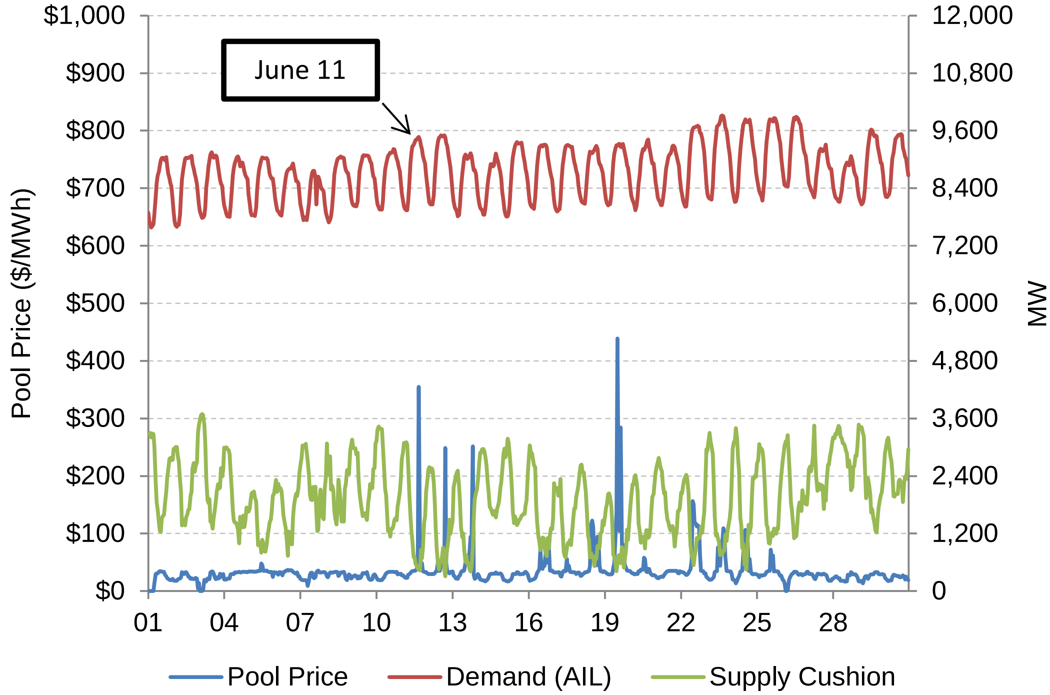
Table 5: Average demand by week (June 2020 and 2019)

2020		
Week start	**Avg. demand (MWh)**	**Weekly change**
Jun-01-2020 (Mon)	8,454	0.2%
Jun-08-2020 (Mon)	8,673	2.6%
Jun-15-2020 (Mon)	8,751	0.9%
Jun-22-2020 (Mon)	9,020	3.1%
Jun-29-2020 (Mon)	8,945	-0.8%
Total change	**491**	**5.81%**

2019		
Week start	**Avg. demand (MWh)**	**Weekly change**
Jun-03-2019 (Mon)	9,143	-0.1%
Jun-10-2019 (Mon)	9,389	2.7%
Jun-17-2019 (Mon)	9,271	-1.3%
Jun-24-2019 (Mon)	9,390	1.3%
Jul-01-2019 (Mon)	9,252	-1.5%
Total change	**109**	**1.19%**

Overall, wind supply in June was relatively strong with an hourly average of 643 MWh, which is a 36% capacity factor. However, wind is a variable resource and in some peak hours wind generation was well below this average. For instance, average wind generation was only 151 MWh in the ten highest pool price hours in June 2020, which is 76% below the monthly average level of wind generation, and is a capacity factor of 8.5%. In combination with increased demand and the restriction on imports, lower wind production caused some low supply cushion outcomes in the peak hours of Thursday, June 11 (see Figure 9).

Figure 9: Hourly demand, supply cushion, and pool price for June 2020

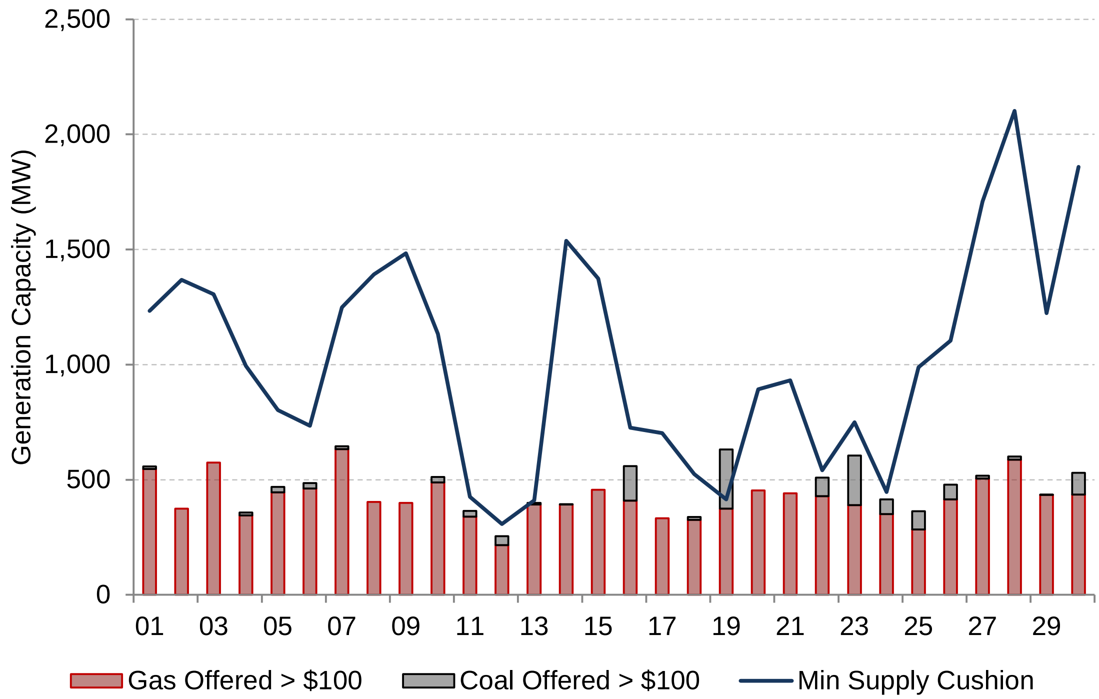


Outages at Alberta thermal units were another factor contributing to the low supply cushion outcomes observed in mid-June. In HE17 of Friday, June 12, a large coal unit went offline for maintenance and did not return until the afternoon of Wednesday, June 24. Another coal plant was offline from June 18 HE24 until June 21 HE08, and a third coal unit went offline for a two-day outage beginning in HE19 of Friday, June 19.

In terms of offer behaviour, there was a limited supplier response to the low supply cushion hours in June. Figure 10 shows how the total amount of thermal capacity offered above $100/MWh changed over the course of the month with variations in supply cushion.[17] The chart illustrates the lowest hourly value for supply cushion on a given day and also provides the thermal capacity offered above $100/MWh in the same hour. As shown, there was not a notable increase in thermal generation priced above $100/MWh on June 11, 12, and 13 when the supply cushion fell below 500 MW in some hours. On June 19 there was an increase in coal capacity offered above $100/MWh, partly in response to the low supply cushion.

[17] This analysis uses Available MW in the Energy Market Merit Order. It does not include assets on Long Lead time or mothballed.

Figure 10: Daily minimum hourly supply cushion and the corresponding amount of thermal capacity offered above $100/MWh



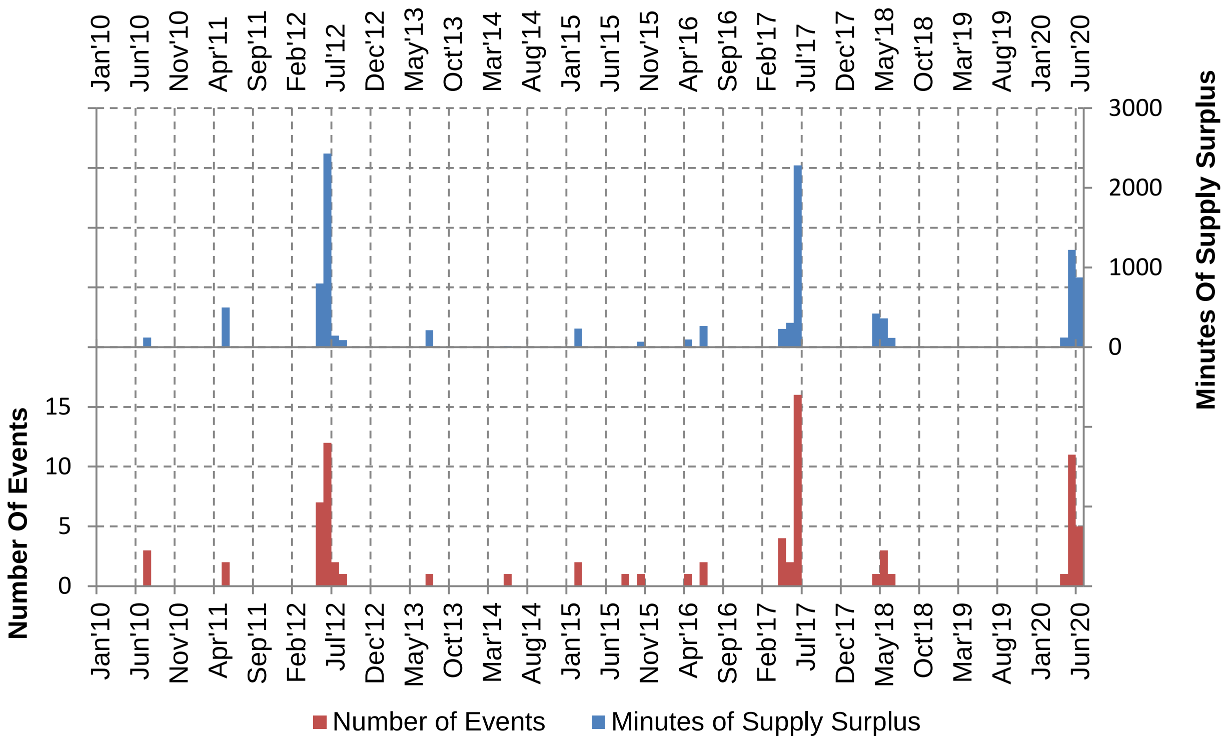
Overall, there were some higher pool prices in June as the market responded to restrictions on the BC/MATL intertie, increased demand, variable wind generation, and coal unit outages. The average pool price for the month settled at $34.51/MWh, 31% higher than the average pool price for May. Although there were a few high pool prices in June, the vast majority of hours had relatively low pool prices, with 92% settling under $50/MWh and 50% settling under $30/MWh.

1.3 Supply surplus events

Supply surplus events are situations where more generation and imports are available at $0.00/MWh than the total amount of load in the market. Spring to early summer is the most common time period for these events to occur and the early hours of the morning is the most common time of day.

A supply surplus event is defined as a continuous period of time during which the SMP was $0.00/MWh. Figure 11 illustrates the frequency and duration of supply surplus events since 2010. With 17 events, 2020 has the third highest number of supply surplus hours since 2010, with only 2012 and 2017 having more.

Figure 11: Supply surplus duration and count of events



During the supply surplus events in 2020, imports levels were significant and the AESO managed ten of the events by limiting the import volume. This 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. Management of the other seven events did not require any involuntary mitigation action by the AESO.

1.4 ATC management

On June 7, 2020 the main transmission line with BC (1201L) was hit by lightning and Alberta experienced a frequency drop to 59.15 Hz and some Alberta load was shed. The path transfer management procedures should have limited the drop to 59.5 Hz. The AESO subsequently investigated the causes. In the interim, import ATC was limited to 550 MW on the BC/MATL interconnection and this continued until June 22, 2020.[18]

The AESO has amended its existing procedures such that it will reduce ATC if:

- there is, or is forecasted to be, inclement weather near the 1201L line, and
- there is low inertia in the system (this is discussed further below).

[18] AESO: ATC Risk Mitigation Measures Information Session Presentation (July 28, 2020)

In addition, the table that AESO uses to identify how much LSSi needs arming for a given import volume and load level in Alberta has been increased substantially (Table 6).[19] As a result, more LSSi will be required to support imports than in the past. Given the levels of LSSi currently contracted with the AESO, there will not be sufficient LSSi available to allow for some of the higher volumes of imports under normal operating conditions.

Inertia in power systems refers to the energy stored in large rotating generators and some industrial motors, which gives them the tendency to remain rotating. The system inertia in power systems is derived from all connected generators being synchronized, meaning that they are all rotating in lock step at the same frequency. This stored energy is valuable in the event that the power system experiences a large and sudden loss in power supply, because the stored energy can temporarily make up for the lost power.[20] A lower level of system inertia means that a large and sudden loss of power supply will cause electrical frequency to fall faster and to a lower level than would have been the case with more system inertia. In a recent presentation, the AESO highlighted that the system inertia of the Alberta grid was generally lower at decreased levels of demand, at elevated levels of wind generation, and when import volumes are high.[21]

In response to the June 7 frequency event, the AESO is incorporating system inertia into the determination of allowable import ATC. In particular, the ratio of import contingency to system inertia cannot be lower than 0.0135.[22] Table 7 provides the minimum level of system inertia that is now required to allow for an import contingency of between 600 MW and 900 MW, at 50 MW increments. The AESO recently provided a scatterplot of system inertia, showing that in 2019 and 2020 it typically ranged from 46,000 to 60,000 MVA.s.[23]

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[19] AESO: Information Document 2011-001R ATC and Transfer Path Management (June 23, 2020)

[20] National Renewable Energy Laboratory: Inertia and the Power Grid: A Guide Without the Spin (May 2020)

[21] AESO: ATC Risk Mitigation Measures Information Session Presentation (July 28, 2019)

[22] Inertia formula = (BC/MATL net schedule – dispatches issued for LSSi) / real-time system inertia

[23] AESO: ATC Risk Mitigation Measures Information Session Presentation (July 28, 2019) - slide 21

Table 6: Increase in LSSi requirements, MW

BC/MT Import ATC (MW)	AIL (MW)											
	7000 to 7499	7500 to 7999	8000 to 8499	8500 to 8999	9000 to 9499	9500 to 9999	10000 to 10499	10500 to 10999	11000 to 11499	11500 to 11999	12000 to 12499	12500 and above
Below 500	NA	0	0	0	0	0	0	0	0	0	0	0
501 to 550	NA	23	10	0	0	0	0	0	0	0	0	0
551 to 600	NA	72	55	24	24	10	0	0	0	0	0	0
601 to 650	NA	110	95	62	62	40	37	42	26	10	0	0
651 to 700	NA	155	144	114	106	90	83	79	64	41	33	31
701 to 750	NA	168	166	140	136	120	115	112	96	84	72	71
751 to 800	NA	162	171	150	151	132	132	131	118	106	94	90
801 to 850	NA	154	170	153	150	139	138	137	127	114	102	100
851 to 900	NA	153	172	154	150	141	137	137	129	114	102	100
901 to 950	NA	152	174	158	153	140	136	137	131	113	101	99
951 to 1000	NA	157	174	160	156	141	136	137	134	113	102	100
1001 to 1050	NA	161	175	164	149	144	135	137	135	113	106	101
1051 to 1100	NA	168	184	169	150	147	137	134	136	114	108	101
1101 to 1150	NA	173	191	173	153	150	136	135	140	117	112	101
1151 to 1200	NA	180	191	189	146	150	137	139	142	119	112	102
1201 to 1250	NA	191	201	197	149	154	136	141	142	123	112	102

Infeasible (insufficient LSSi) prior to June 22 implementation and still infeasible

Infeasible (insufficient LSSi) after June 22 implementation

Table 7: Import contingency and the minimum level of system inertia required

Import contingency (MW)	Required system inertia (MVA.s)
600	44,444
650	48,148
700	51,852
750	55,556
800	59,259
850	62,963
900	66,667

1.5 Interties

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. When the relevant places are different electricity markets, this is expected to occur as a result of traders scheduling exports from low price markets and associated imports into high price markets.

1.5.1 BC/Montana intertie

Alberta remained a net importer of energy, with greater than 975 GWh of net-scheduled imports in the quarter.

Figure 12: Total imports and exports, and Mid C-Alberta price differential

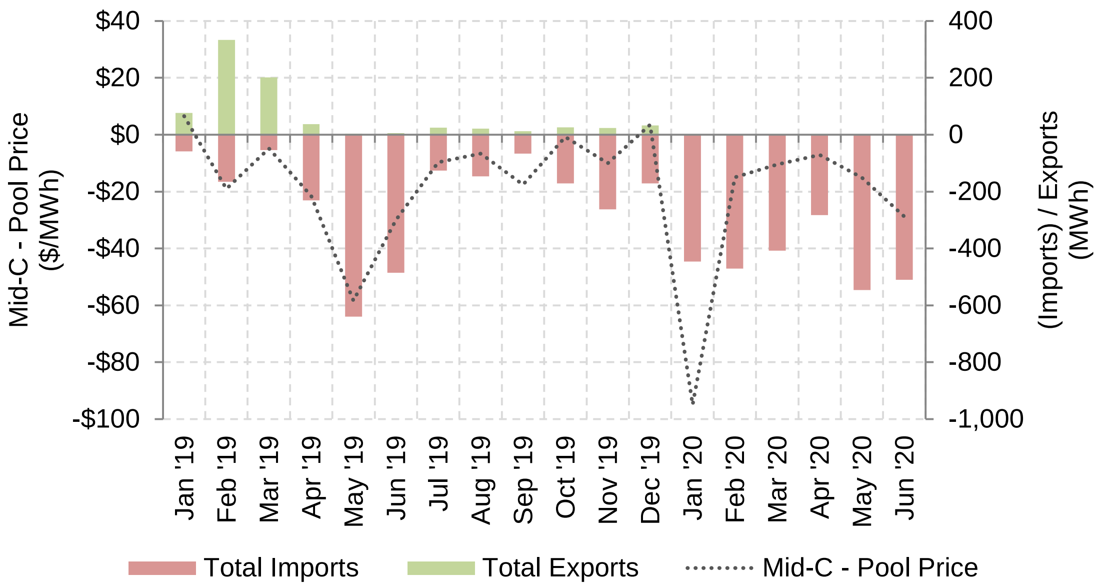
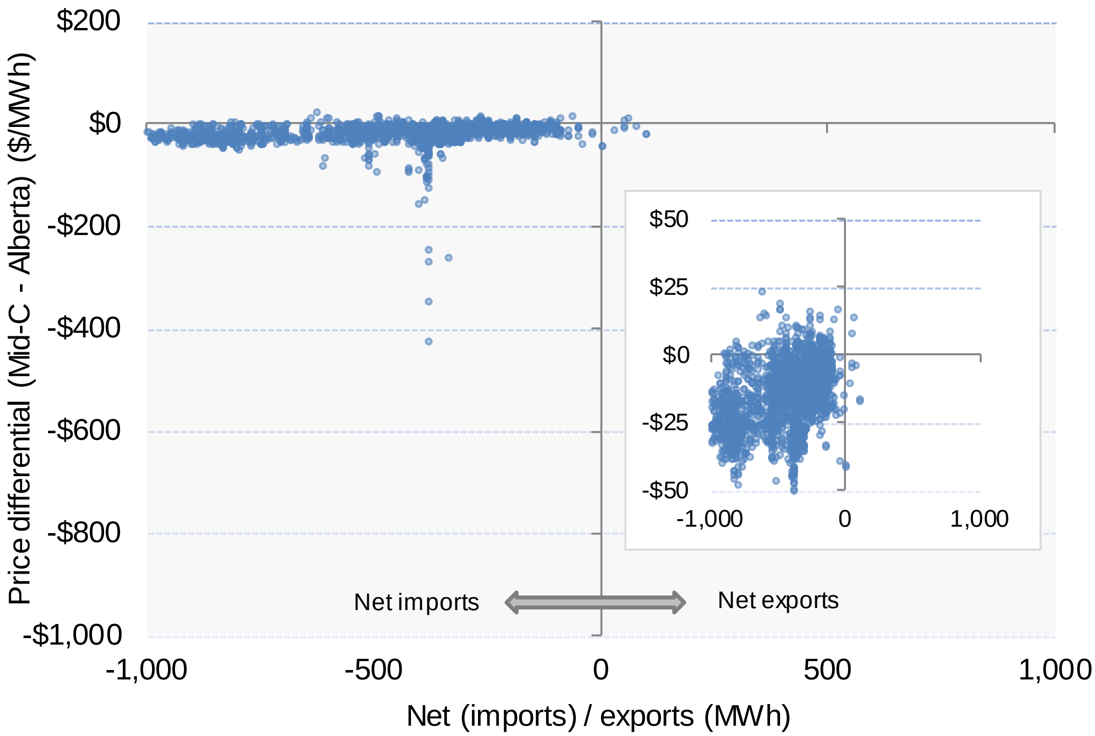


Figure 12 compares the price differential between the Alberta and Mid-Columbia (Mid-C) markets with the volumes of exports and imports between the two on a monthly time scale. It shows that overall trade is in the profitable direction on an index-to-index basis.

Figure 13 shows the plot of hourly net flow versus the hourly profit during the quarter with profit defined as Mid-C price less the Alberta pool price; the inset graph focuses on price differences between positive and negative $50/MWh. Profitable flow should exhibit itself with most of the hourly data plotting in the north-east and south-west quadrants of the figure.

The price of electricity in the Mid-C market was generally lower than the price of electricity in Alberta. In hours where this price differential was large and negative, net imports to Alberta were substantial; Alberta was not an exporter of electricity in any of these hours. These results are consistent with an efficient market.

Figure 13: Intertie price differentials and net flow on the BC/MATL intertie



Figures 12 and 13 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.

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, pool price is not known until after the energy has flowed.

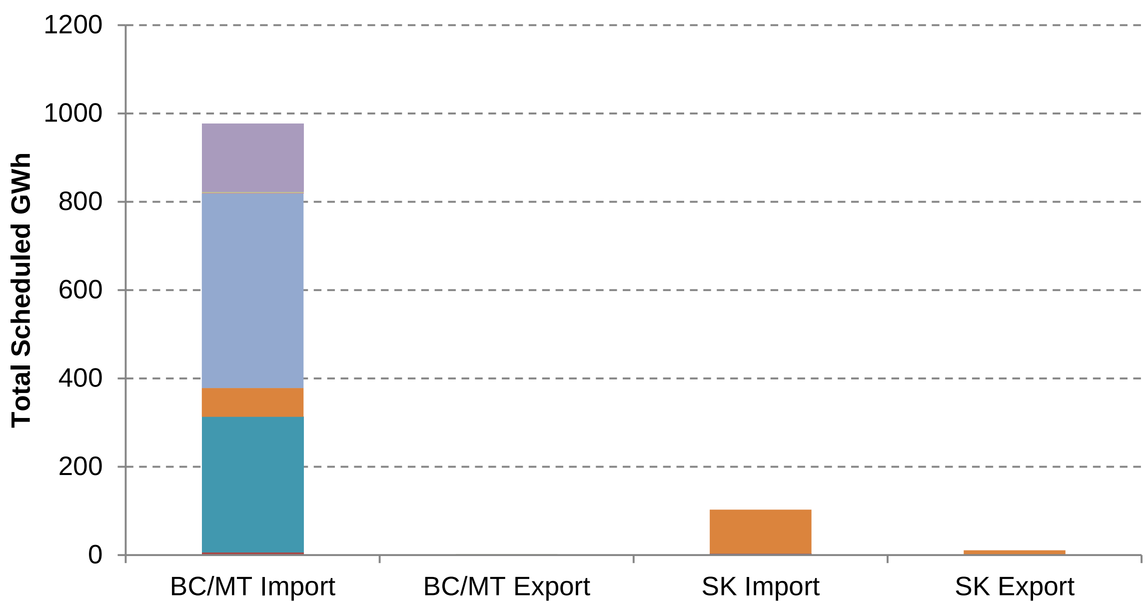
In addition, the charts do not focus on the entities flowing energy and their motivations. While some may flow energy for portfolio reasons, it is assumed that any significant arbitrage opportunity will be exploited. The terms and conditions of transmission access on the interties are such that it is very difficult to economically withhold energy. The effect is that the interties become akin to free flowing pipelines of energy to the extent that there is sufficient pressure (profit) to do so.

1.5.2 Participation on the interties

A relatively small number of market participants schedule electricity trades on Alberta's interties. Some of these participants are only active in scheduling trade on one intertie and/or in one direction. The market shares of market participants on Alberta's interties with (i) British Columbia and Montana and (ii) Saskatchewan in Q2 2020 are illustrated in Figure 14. Different market participants are represented with different colours. The figure shows the high level of imports into Alberta on the BC/MATL intertie. There was very little flow otherwise.

No concerning flows of electricity have been identified during the quarter. Participation patterns are not significantly different from previous quarters but the limited number of intertie participants means that the MSA closely monitors this aspect of the electricity market.

Figure 14: Intertie participation in Q2 2020

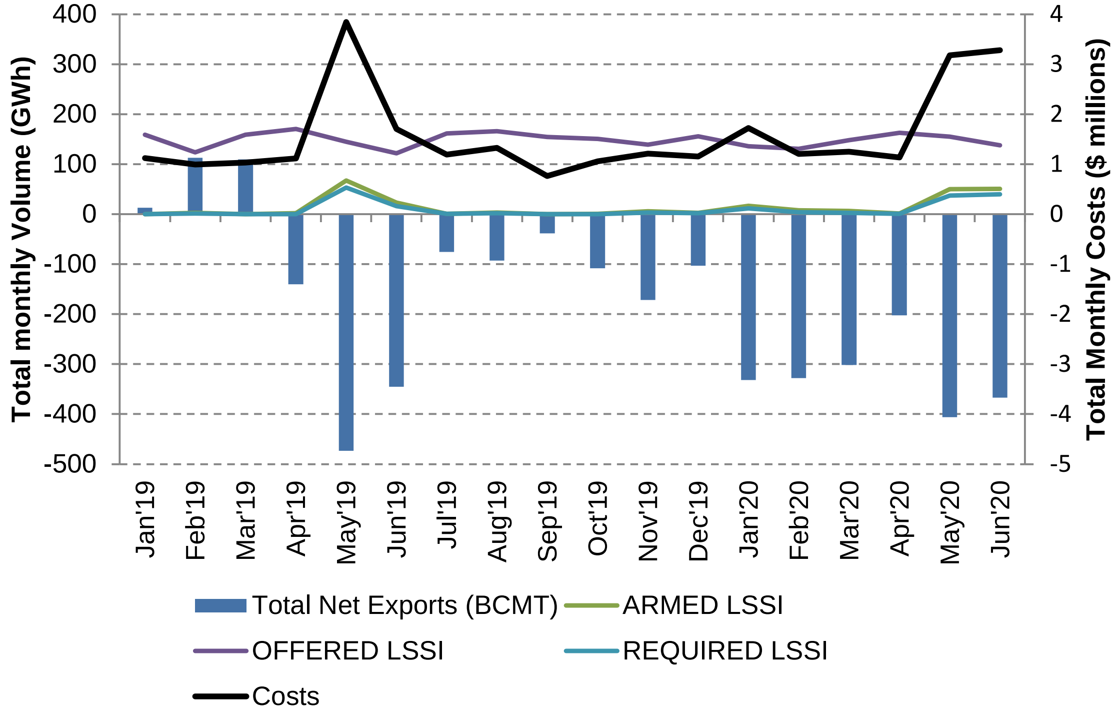


1.5.3 Load Shed Service for Imports (LSSi)

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 at the increased capability. LSSi providers are paid for availability, arming, and tripping in the event they are tripped to arrest the drop in frequency.

LSSi costs were the highest during the spring run-off season when imports are at their peak. It is during these times that most of the LSSI is armed, although in other months with less armed or required LSSI the costs amount to approximately $1 million dollars per month. As of June 30, 2020 estimated costs were $11.8 million[24], 20% more than the same time in 2019 (Figure 15).

Figure 15: LSSi and net imports



[24] LSSi estimates subject to settlement adjustments

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. These are; 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.[25]

Operating reserves in Alberta are procured on the business day before the delivery day. The procurement uses an auction mechanism in which the AESO determines the procurement volume for a set of products in accordance with the Alberta Reliability Standards in order to reliably operate the power system. The various products are procured sequentially.

For active reserve products, offer and settled prices are expressed as a premium (usually a discount) to pool price in the delivery period. Capacity that has been allocated to provide active reserve products in a given delivery hour do not participate in the energy market in those delivery hours.

The AESO also procures standby reserves in case active reserves are insufficient to reliably operate the power system. Unless activated in real-time, the assets providing standby reserves in a given delivery hour may continue to participate in the energy market in that hour.

All operating reserve products have certain technical requirements that must be satisfied in order for an asset to be eligible to provide the product. These technical requirements limit participation in operating reserve markets. Generating assets provide most of the operating reserves in Alberta, with some hydroelectric resources being particularly well suited to providing these products. Some loads and interties are also eligible to provide some products.

2.1 Costs and procurement volumes

In Q2 2020, as reported in Table 8, the total cost of operating reserves was 69% lower than the same quarter the previous year. The primary driver of these costs is pool price which in Q2 2020 was down almost 50% from Q2 2019. June 2020 operating reserves costs were elevated in part due to increased standby activation volumes of spinning reserves at an average cost of almost $50/MWh (average pool price in June was $34.51/MWh). Most of these activations were to support high levels of import on the BC/MATL interconnection.

Commencing June 1, 2020 AESO began procuring 20 MW/h less active regulating reserves. WECC does not mandate the amount that the AESO must procure; the AESO buys as much as it determines to be necessary. The AESO uses regulating reserves for both AGC and managing system ramps. The MSA agrees that procuring less regulating reserves contributes positively to the market as prices will respond more readily to changes in the supply-demand balance.

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

Table 8: Detailed breakdown of OR costs in Q2 2020

	Apr-20	May-20	Jun-20	Q2 2020	Q2 2019	% Change
Total Cost ($ Millions)						
Active Procured	**4.0**	**4.7**	**5.3**	**14.0**	**53.7**	***-74%***
RR	2.6	0.6	1.5	4.7	15.1	*-69%*
SR	0.7	2.5	2.5	5.8	20.7	*-72%*
SUP	0.6	1.6	1.3	3.5	17.9	*-80%*
Standby Procured	**0.4**	**0.5**	**0.3**	**1.2**	**2.1**	***-42%***
RR	0.1	0.3	0.2	0.6	1.0	*-40%*
SR	0.2	0.2	0.1	0.5	0.7	*-26%*
SUP	0.1	0.0	0.0	0.1	0.4	*-74%*
Standby Activated	**0.3**	**1.0**	**3.1**	**4.4**	**8.6**	***-48%***
RR	0.0	0.1	0.2	0.3	0.2	*124%*
SR	0.2	0.7	2.3	3.2	6.0	*-47%*
SUP	0.1	0.2	0.6	0.9	2.4	*-63%*
Total	**4.7**	**6.2**	**8.7**	**19.6**	**64.4**	***-69%***
Total Volume (GWh)						
	Apr-20	**May-20**	**Jun-20**	**Q2 2020**	**Q2 2019**	***% Change***
Active Procured	**437.2**	**517.4**	**439.6**	**1,394.2**	**1,460.2**	**-5%**
RR	114.3	101.3	98.2	313.8	342.1	*-8%*
SR	161.8	208.0	170.8	540.5	559.3	*-3%*
SUP	161.2	208.0	170.7	539.9	558.9	*-3%*
Standby Procured	**160.9**	**163.5**	**157.7**	**482.1**	**601.1**	***-20%***
RR	57.3	59.5	57.4	174.1	174.3	*0%*
SR	77.0	78.0	75.5	230.5	289.8	*-20%*
SUP	26.5	26.0	24.9	77.4	137.0	*-43%*
Standby Activated	**9.1**	**32.2**	**70.0**	**111.4**	**106.0**	***5%***
RR	0.4	2.3	5.1	7.8	2.7	*189%*
SR	5.8	20.2	46.0	72.0	70.7	*2%*
SUP	3.0	9.7	18.9	31.6	32.6	*-3%*
Total	**607.2**	**713.1**	**667.3**	**1,987.7**	**2,167.3**	***-8%***
Average Cost ($/MWh)						
	Apr-20	**May-20**	**Jun-20**	**Q2 2020**	**Q2 2019**	***% Change***
Active Procured	**9.09**	**9.07**	**12.12**	**10.04**	**36.80**	**-73%**
RR	22.81	6.01	15.00	14.94	44.27	-66%
SR	4.50	11.97	14.87	10.65	36.93	-71%
SUP	3.96	7.66	7.72	6.57	32.10	-80%
Standby Procured	**2.43**	**3.01**	**2.01**	**2.49**	**3.44**	**-27%**
RR	1.22	4.92	4.27	3.49	5.85	-40%
SR	3.03	2.53	0.90	2.16	2.34	-7%
SUP	3.31	0.12	0.17	1.23	2.68	-54%
Standby Activated	**37.85**	**30.93**	**44.19**	**39.83**	**80.69**	**-51%**
RR	40.40	37.88	47.29	44.16	57.15	-23%
SR	41.74	33.76	49.70	44.59	85.03	-48%
SUP	29.97	23.39	29.92	27.91	73.25	-62%
Total	**7.76**	**8.67**	**13.10**	**9.88**	**29.70**	***-67%***

The cost of standby activations increases when net imports into Alberta increase. The reason for this is that scheduling high levels of imports into Alberta requires the AESO to schedule more active contingency reserves in real-time to ensure that reliability is maintained in the event of an intertie trip. Since the level of scheduled imports is not known with certainty when reserves are procured (on the business day before delivery), the AESO sometimes activates standby contingency reserves for this purpose.

2.2 Unusual operating reserves events

"Unusual operating reserves events" are those that resulted in higher than normal auction procurement by the AESO of contingency reserves. The AESO typically procures higher than normal contingency reserves when it anticipates higher than normal import flows on the BC/MATL intertie. These higher than normal procurements occur when the intertie is expected to be the most severe single contingency. These decisions are made close to the time of the auction. Three such events are listed here with brief comments and observations.

April 1: At the Watt-Ex auction on March 31, AESO bought 344 MW of active on-peak SPIN and SUPP, which is higher than normal and is based on AESO's internal forecast of load and import levels. The offered volumes in the SUPP market were not sufficient to meet the increased demand and price was set close to the AESO's bid cap of $40 without managing to fill all the buy requirements. This means that all SUPP providers received (pool price + $40) per MWh of active on-peak SUPP. The same situation did not occur in the SPIN market and the corresponding SPIN price was -$27.75. This means that active SPIN providers received (pool price -$27.75) per MWh, for what is a superior service to SUPP. Ultimately the cost of the active SUPP that day was very high and it is not evident that it was due to scarcity of supply. Given more notice, more supply would likely have been offered, perhaps via standing offers.

Alberta reliability requirements dictate that no less than 50% of all contingency reserves must be SPIN which is generally what AESO buys in the market. On some occasions, there are many more MWs offered into the SPIN market than the SPIN demand and the untaken offers are cheaper than some of the more expensive SUPP offers required to meet the SUPP demand. To reduce overall costs, consideration should be given to design a scheme whereby a single auction is conducted by combing all the offers for both SPIN and SUPP into one stack. SPIN offers can provide SUPP whereas the opposite may not be true. Offers would need a flag if they were only valid for SUPP or SPIN.

April 29: At the Watt-Ex auction on April 28, in anticipation of increased imports, AESO bought significantly more standby SPIN and SUPP than usual. For the on-peak hours the AESO bought 200 MW of standby SPIN (vs 130 MW the day before and the day after) and 130 MW of standby SUPP (vs 35 MW the day before and the day after). This tends to drive up prices for two reasons:

- Increased demand should move the price up the offer curve as in any normal market.

- Increased demand in the standby market is a strong signal to sellers that the activation rate for the delivery day will likely be higher than usual and adjust their bids accordingly. Sellers have two parameters for bidding:

    - The hourly premium that they will receive every hour of the contract period (16 hours for on-peak and 8 hours for off-peak); and,

    - The activation rate received in the event that they are activated from standby to active.

The two parameters are combined into a single number for the purpose of the auction. In this case some sellers asked for, and received, very high premium values.

On April 29, very little standby was activated and the total cost for standby reserves was driven by the cost of the hourly premiums paid to the sellers. Some 60 MW of coal assets sold standby SPIN at a premium of just under $100/MWh while about 60 MW of SUPP sellers were commanding premium prices around $50/MWh. Prices for the hourly premiums in the standby markets vary considerably across time but, when the energy market is yielding prices in the range $20 - $40/MWh, to pay standby reserves more than this appears anomalous. Total costs for standby SPIIN and SUPP reserves for the day were about $215,000.

April 30: At the Watt-Ex auction on April 29, AESO bought volumes of active and standby reserves for April 30 more typical of weekday conditions, resulting in moderate prices. On April 30, large import volumes flowed and this required significant volumes of standby reserve activations (some 1500 MWh) which contributed to a high overall cost for the day. Total costs for standby reserves on the day were more than $75,000.

3 THE FORWARD MARKET

Standard shape forward products include flat (all hours), on-peak, and off-peak products (for various term lengths). Forward trade volumes of standard shape products for the most common term lengths are reported by trade date in Table 9. The volume of trades for most standard shape forward market contracts has dropped significantly since Q4 2018. There was very little trading activity in Q2 2020. Most activity was in the trading of monthly contracts, although even there the volume was lower than in prior years. There was remarkably little trading of annual products in the quarter.

Table 9: Forward market total trade volumes, standard products only (TWh)[26]

		Daily	Monthly	Quarterly	Annual	Other	Total
2016	Q1	0.22	9.36	1.78	12.37	3.01	26.73
	Q2	0.19	8.25	0.58	4.50	1.08	14.60
	Q3	0.07	6.80	1.23	4.56	0.25	12.90
	Q4	0.09	5.44	1.46	3.78	0.47	11.24
	Year	**0.57**	**29.85**	**5.05**	**25.20**	**4.81**	**65.47**
2017	Q1	0.06	6.53	3.03	4.57	1.86	16.05
	Q2	0.13	6.87	2.31	11.13	0.84	21.27
	Q3	0.18	6.77	2.13	5.51	1.17	15.76
	Q4	0.06	8.24	3.51	7.50	1.38	20.69
	Year	**0.43**	**28.40**	**10.98**	**28.70**	**5.26**	**73.78**
2018	Q1	0.15	7.28	0.60	4.47	0.41	12.91
	Q2	0.16	6.06	1.20	5.80	0.28	13.49
	Q3	0.10	4.59	0.22	3.60	0.53	9.04
	Q4	0.10	6.55	2.33	6.88	0.43	16.30
	Year	**0.52**	**24.47**	**4.35**	**20.75**	**1.65**	**51.74**
2019	Q1	0.16	6.01	2.30	4.16	0.72	13.35
	Q2	0.10	5.55	0.76	4.88	0.65	11.94
	Q3	0.05	3.73	1.92	1.90	0.26	7.86
	Q4	0.03	4.55	1.30	1.92	0.85	8.65
	Year	**0.33**	**19.84**	**6.27**	**12.87**	**2.49**	**41.80**
2020	Q1	0.07	4.04	1.03	1.82	0.31	7.27
	Q2	0.04	3.47	0.13	0.81	0.26	4.71

[26] Reported volumes include trades undertaken on NGX ICE, trades undertaken at Canax and then settled on NGX ICE and trades at Canax that are settled directly between the parties to the trade. This group of trades are obtained from Canax and incorporated into our data base. An error was discovered that affected the volumes for Q4 2019 and Q1 2020 as originally reported.

The final source of forward market data is any trades occurring directly between market participants that did not involve the use of a broker. The MSA requests this data periodically, the last time being for data to the end of 2018.

3.1 Trading of monthly products

Power pool prices are typically higher in summer and winter than in spring and autumn. As a result, forward prices for delivery in these periods typically follow this pattern. Specifically, forward prices are typically lower in the spring compared the winter, as the warmer spring weather reduces heating load and melts the snowpack, increasing hydro generation (primarily through imports from the west). Monthly prices then increase for the summer months as temperature increases drive cooling load and reduce the availability of Alberta's thermal generation capacity. This is caused by gas-fired units being derated due to higher ambient air temperatures and coal-fired units being derated due to warmer cooling ponds which cannot dissipate waste heat as efficiently as at cooler ambient temperatures. These factors are reflected in the levels of forward prices for monthly flat contracts since the start of the year, which are illustrated in Figure 16.

Figure 16: Forward prices for near term months (January to June, 2020)[27]

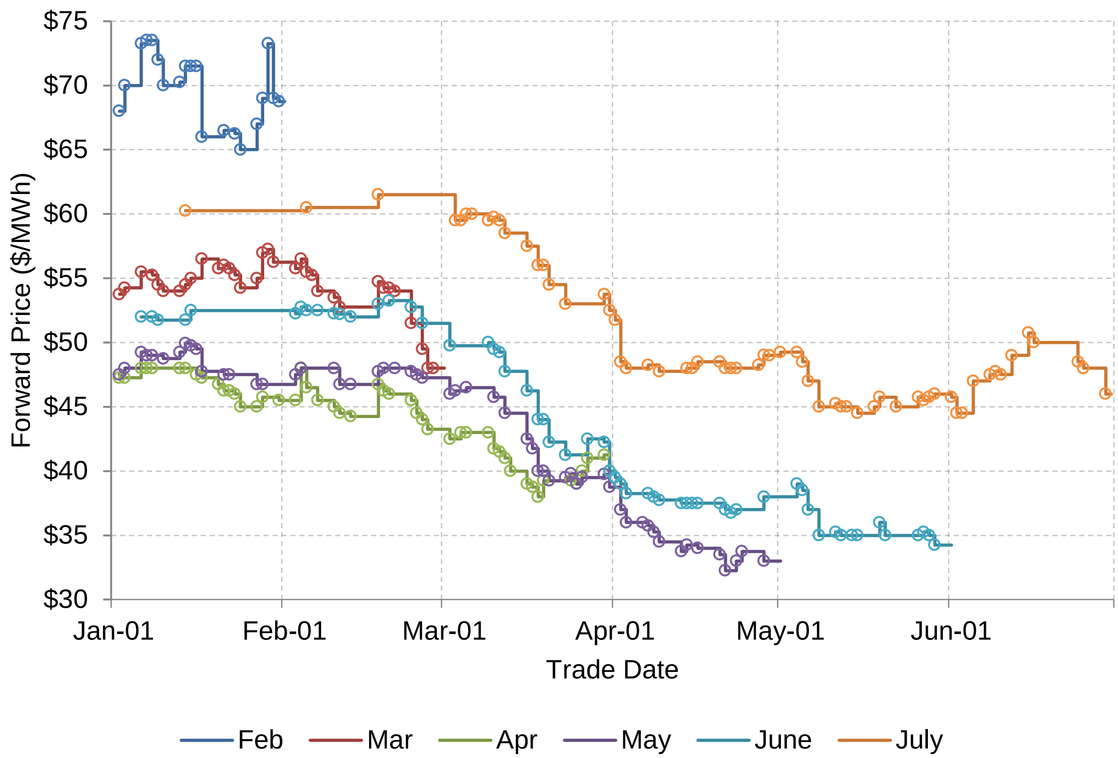


Figure 16 also illustrates that forward prices began to decline in mid-to-late February as the spread of COVID-19 began to escalate.[28] Over the course of February, the forward prices for March and April contracts fell by 14.7% and 4.9%, respectively. Forward prices declined further

[27] This analysis uses the last traded price for a given contract on a daily basis. The analysis does not consider bid or offer prices just trades executed.

[28] BBC News: Coronavirus: World must prepare for pandemic, says WHO (February 25, 2020)

in March as Alberta announced its first presumptive case of COVID-19 on March 5 and OPEC+ failed to agree on oil production cuts in a meeting on March 6.[29] Over the course of March, the May and June contracts fell by 18.4% and 22.3%, respectively (Figure 17). Forward prices declined further in April, with the May and June contracts falling further by 14.8% and 5.0%, respectively. The June contract declined another 9.9% in May and the monthly contracts for Q3 all fell as well. In total, the price of the May contract fell by 30.9% since February 18, the price for June fell by 35.4% and July declined by 25.2%. The forward market seemed to find a bottom in June with prices for the Q3 months relatively unchanged over the month (Figure 17).

Figure 17: Changes in forward prices for March to September flat contracts for trades between February and June 2020

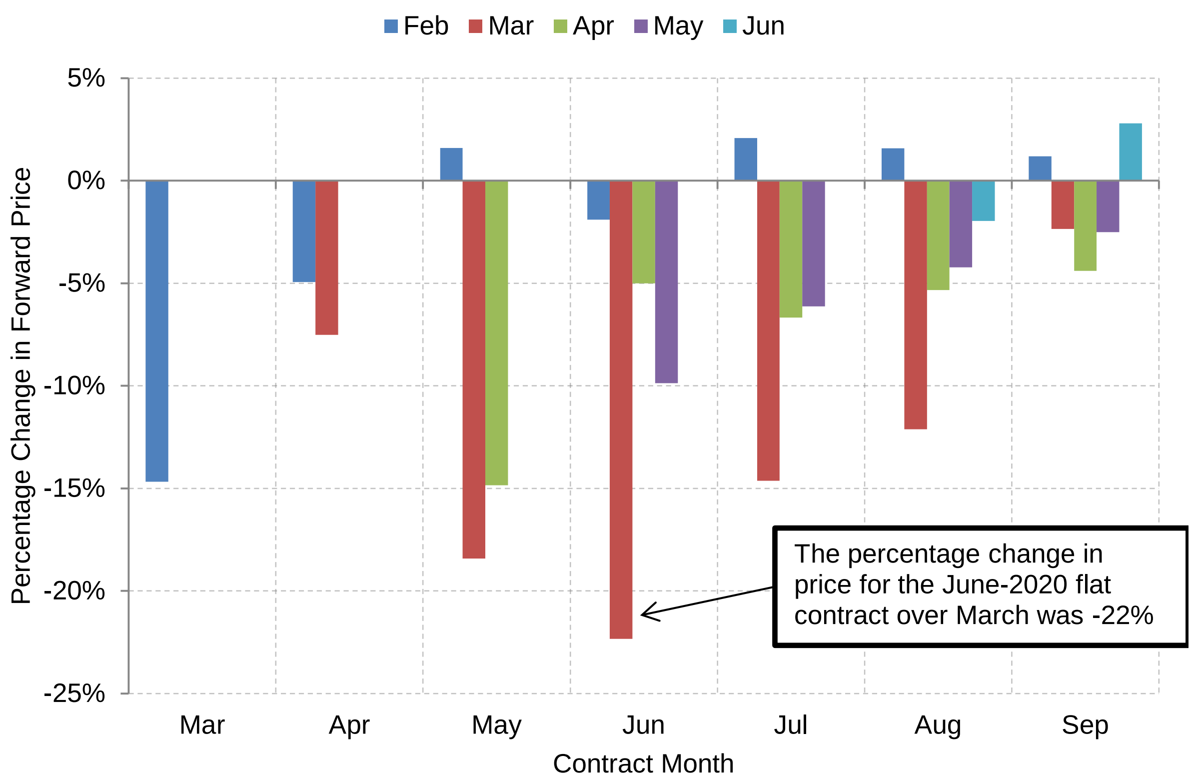


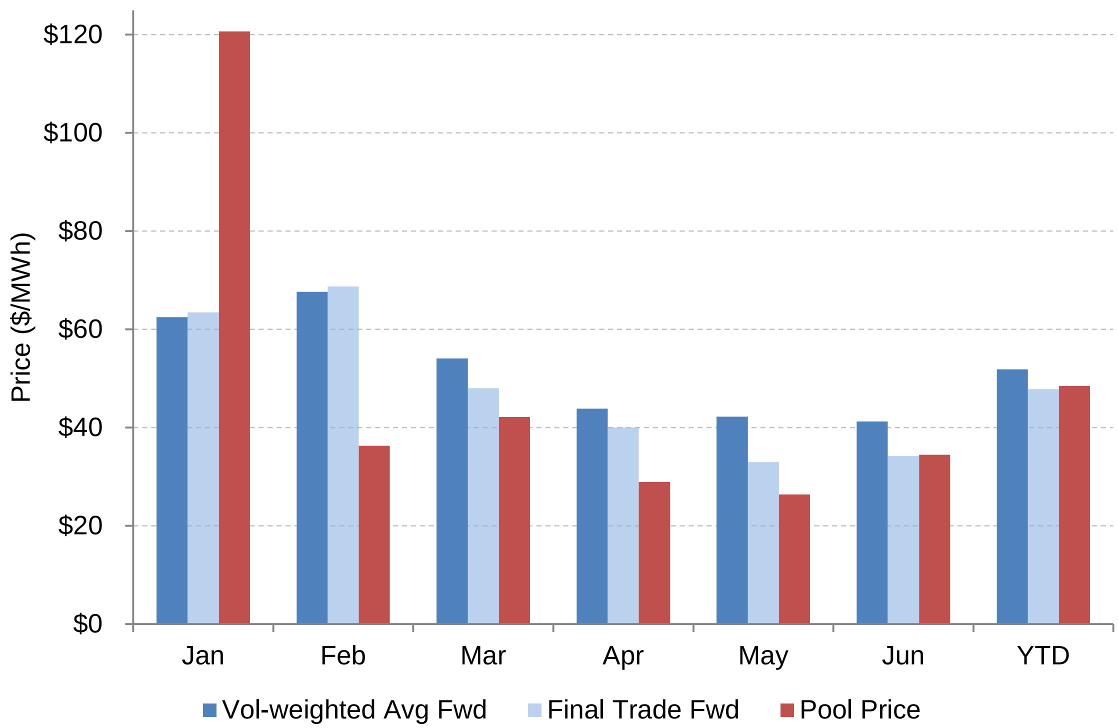
Figure 18 shows how monthly flat forward prices have compared with realized pool prices for the first six months of 2020. The figure shows the volume-weighted average forward price, which is an indicator of the overall pricing levels for a contract, and the price of the final forward trade, which indicates the market's expectations for pool prices when it had the most information. The decline in forward prices over time can be seen for the March to June contracts

[29] CTV: Alberta's first presumptive case of COVID-19 is in the Calgary Zone (March 5, 2020)

Calgary Herald: Coronavirus 'taking the oil market hostage', as prices plunge, Canadian firms hunker down (March 7, 2020) with the volume-weighted average price being higher than the final trade price. Despite the declines in forward prices, the final trade prices for March, April, and May were still above realized pool prices (Figure 18).

For the June contract, the final forward trade was slightly below the realized pool price for the month but forward prices were well above this level earlier in the quarter. Overall, the prices of flat monthly contracts in the forward market flat have traded at a premium to pool prices so far this year by $3.40/MWh (comparing volume-weighted average forward prices with realized pool prices), as the forward premiums for the February through June contracts have more than offset the deep discount for the January contract.

Figure 18: Monthly flat forward prices and pool prices (January to June 2020)



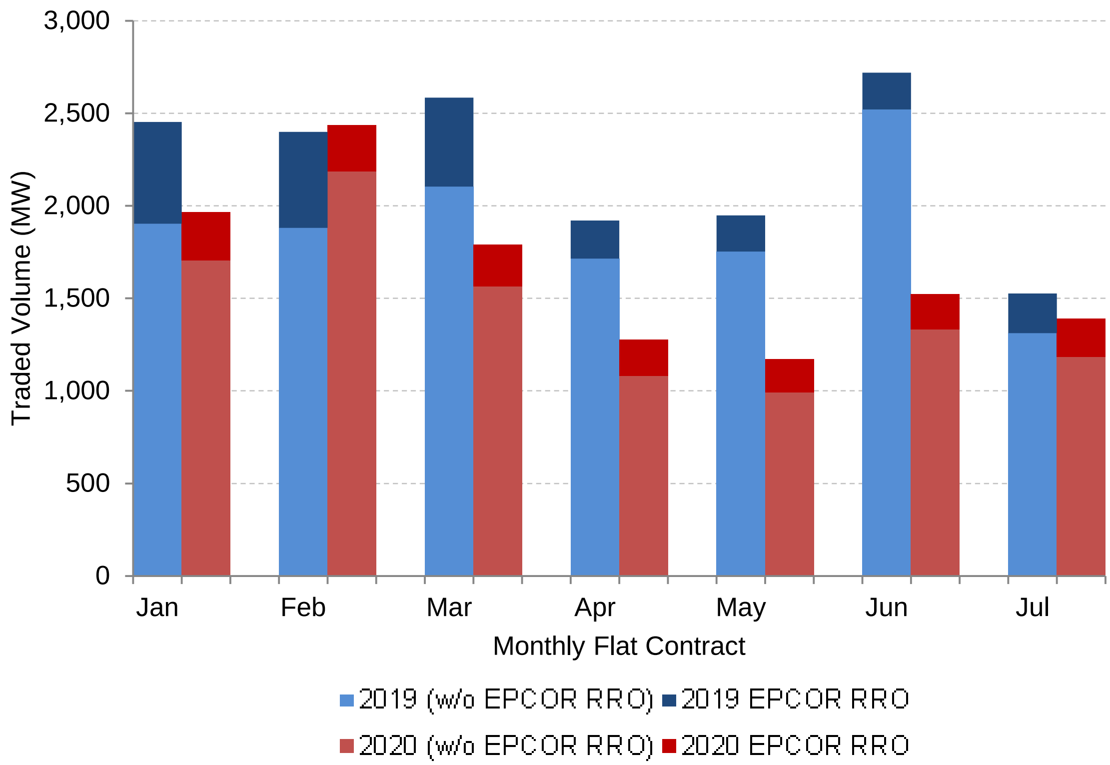
A fall in trading activity has been observed in the monthly flat contracts in 2020 compared to the corresponding months in 2019 (see Figure 19). With the exception of the February contract, traded volumes for all 2020 monthly flat contracts year-to-date are lower than last year.[30] The reduction is particularly notable for the May and June contracts, with traded volumes down 40%

[30] The traded volume is the volume of electricity, in MW, exchanged financially on an hourly basis within a trade. Total volume is the total amount of electricity exchanged financially over the duration of the trade; total volume is calculated by multiplying the traded volume by the number of applicable hours within the contract. For a June flat contract, 1 MW of traded volume is equivalent to (24 x 30) = 720 MWh of total volume. For a June extended peak contract, 1 MW of traded volume is equivalent to (16 x 30) = 480 MWh of total volume.

and 44%, respectively. While the comparison for the July contract is more favourable, traded volumes for the July 2019 contract were low.

However, since the April 2019 contract month, EPCOR has procured approximately 50% of its forecasted RRO load through full-load contracts and full-load volumes are not included in Figure 19.[31] Therefore, prior to the April 2019 trade month, EPCOR purchased greater volumes of monthly flat products to hedge its RRO load. This greater flat procurement for the months of Q1 2019 accounts for some of the change in traded volumes year over year, as highlighted in Figure 19.

Figure 19: Traded volumes for monthly flat contracts (2019 and 2020)



To see how the distribution of trading over time for the June 2020 contract compared with June 2019, Figure 20 shows the cumulative traded volumes for each contract beginning on December 1 the year prior (six months in advance of the contract start). As shown, trading activity for June 2020 was relatively low from January through March compared to the same period for the June 2019 contract. There was a notable amount of trading activity for the June 2020 contract on March 31 and April 2 but trading activity subsequently declined relative to the levels observed in the previous year for the June 2019 contract.

[31] Full load contracts allow EPCOR to financially hedge a specified percentage of its total RRO load. EPCOR's RRO load will vary depending on a number of factors, such as the time of day and the weather, and the traded volumes for the full load contracts will not be known for certain until settlement. See AUC Decision 24284-D01-2019.

Figure 20: Traded volumes for June 2019 and 2020 flat contracts (6 months prior to contract start)

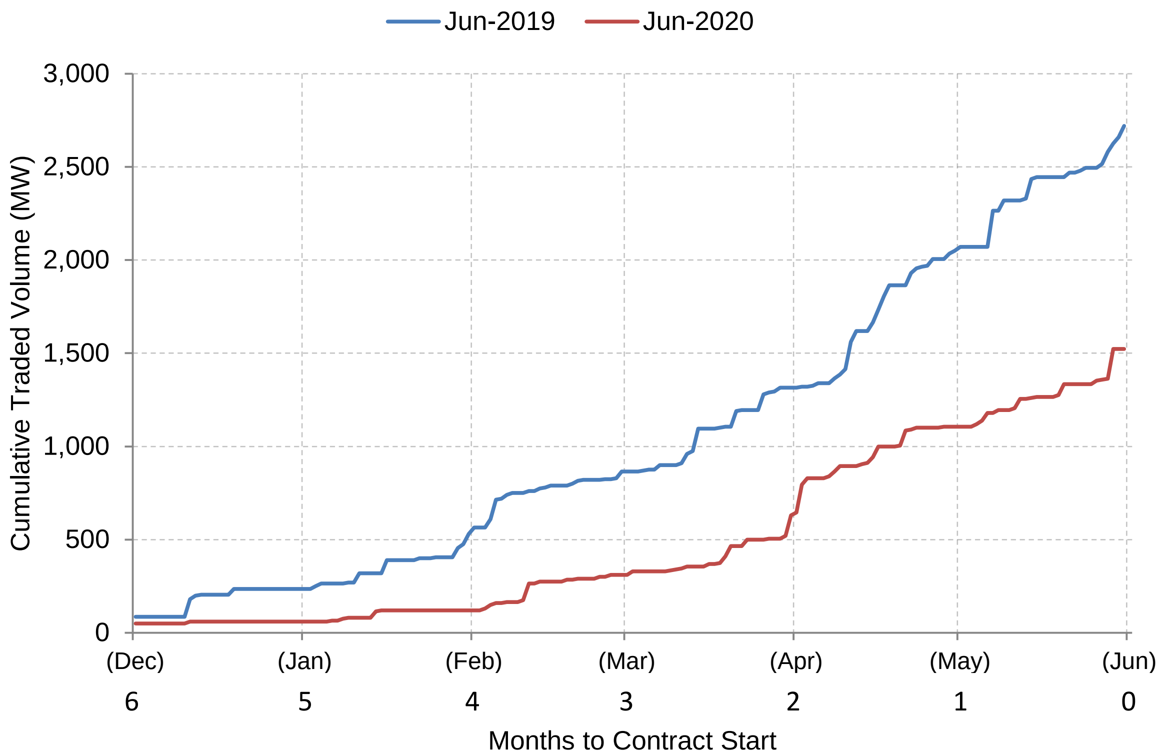
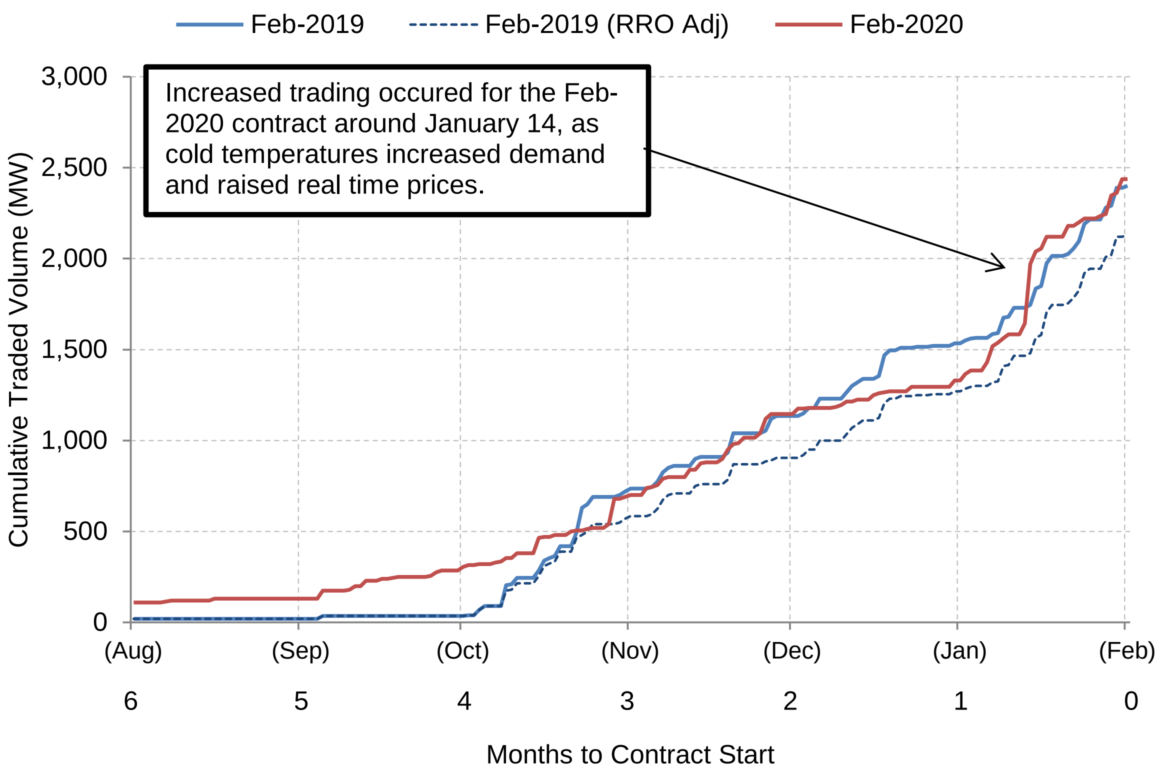


Figure 21 shows the same analysis for the Feb 2020 and Feb 2019 contracts. This example contrasts with the June contracts because the overall traded volumes for the two February contracts are similar. Accounting for the fact that the EPCOR RRO has reduced its procurement of flat contracts between Feb 2019 and Feb 2020 (the dashed line), traded volumes were slightly higher in 2020.[32] As shown, the liquidity of both contracts was quite low prior to October, and in November the level of overall trading was very similar. Activity for the 2020 contract declined a little in December but then increased substantially with almost 540 MW trading over the week beginning January 13, 2020. This was a cold week in Alberta and the real time market set record highs for the daily average pool price; this volatility contributed to increased trading levels of forward products.

[32] AUC Decision 24284-D01-2019 (February 21, 2019)

Figure 21: Traded volumes for February 2019 and 2020 flat contracts (6 months prior to contract start)[33]



An important metric for overall market liquidity is traded volumes as a percentage of realized demand. This calculation totals the traded volume of all trades applicable to a certain period and compares it to the market demand for that period. For example, a Calendar 2020 (CAL20) flat trade would be applicable to every hour in 2020, and a monthly June 2020 extended peak trade would be applicable to HE8-23 for every day in June 2020; both trades would be applicable to June 2020 even though the trades may have occurred months or years ago.

Table 10 shows the calculation of daily traded volumes for delivery the week beginning June 8, 2020. As shown, the flat shaped contracts make up the majority of the traded volumes. On June 8 for example, the traded volumes of applicable flat trades was 5,257 MW, 92% of the total. This 5,257 MW figure is mainly comprised of CAL20 trades (2,833 MW), monthly June 2020 trades (1,523 MW) and Q2 2020 trades (795 MW), with the remainder of the volume coming from other trades, such as multi-year and balance-of-month trades. By accounting for the fact that the extended peak and extended off-peak periods cover 16 and 8 non-overlapping hours per day respectively, and adding the average expected volume of full-load RRO trades, a traded volume number can be calculated; in this example it amounts to 5,708 MW.

[33] The RRO adjustment subtracts the difference between EPCOR's procurement volume of 2019 February flat and 2020 February flat.

Table 10: Calculating traded volume as a percentage of demand (AIL), example of June 2020

Contract date (day of week)	Standard contracts traded volume (MW)			RRO full load volume. (MW)	Traded volume (MW)
	Flat (7x24)	Ext peak (7x16)	Ext off-peak (7x8)		
Jun-08-2020 (Mon)	5,257	266	100	240*	5,708
Jun-09-2020 (Tue)	5,257	266	100	240*	5,708
Jun-10-2020 (Wed)	5,257	266	100	240*	5,708
Jun-11-2020 (Thu)	5,277	266	100	240*	5,728
Jun-12-2020 (Fri)	5,377	266	100	240*	5,828
Jun-13-2020 (Sat)	5,278	266	100	240*	5,729
Jun-14-2020 (Sun)	5,278	266	100	240*	5,729

* The RRO full load volumes are estimated based on average expected block sizes

For June 2020 the average traded volume was 5,780 MW. This figure can be compared to the average realized demand for the month. A higher percentage of traded volumes relative to market demand is generally indicative of more hedging in the market, to the extent that consumers are buying the forward contracts and generators are selling them. In June 2020 traded volumes as a percent of AIL was 66%, compared with 76% for June 2019. Table 11 shows the same figures for the first six months of the year. As shown, traded volumes as a percentage of demand have generally declined year-over-year and in some months, such as March and June, the decline has been significant. Year-to-date, traded volumes as a percentage of market demand have been 5% lower in 2020 compared to 2019 on average.

Table 11: Traded volume as a percentage of demand for January to June (2019 and 2020)

	2020				2019			
Contract month	Standard contracts traded volumes (MW)	RRO full load traded volumes (MW)	Average AIL (MWh)	Traded volumes % of AIL	Standard contracts traded volumes (MW)	RRO full load traded volumes (MW)	Average AIL (MWh)	Traded volumes % of AIL
Jan	5,979	316*	10,517	60%	6,480	0	10,308	63%
Feb	6,472	300*	10,208	66%	6,681	0	10,689	63%
Mar	5,657	268*	10,008	59%	6,849	0	9,919	69%
Apr	5,396	236*	9,091	62%	6,024	256*	9,306	67%
May	5,164	224*	8,503	63%	6,052	244*	9,106	69%
Jun	5,540	240*	8,739	66%	6,752	260*	9,284	76%
YTD	**5,696**	**264***	**9,510**	**63%**	**6,470**	**127***	**9,759**	**68%**

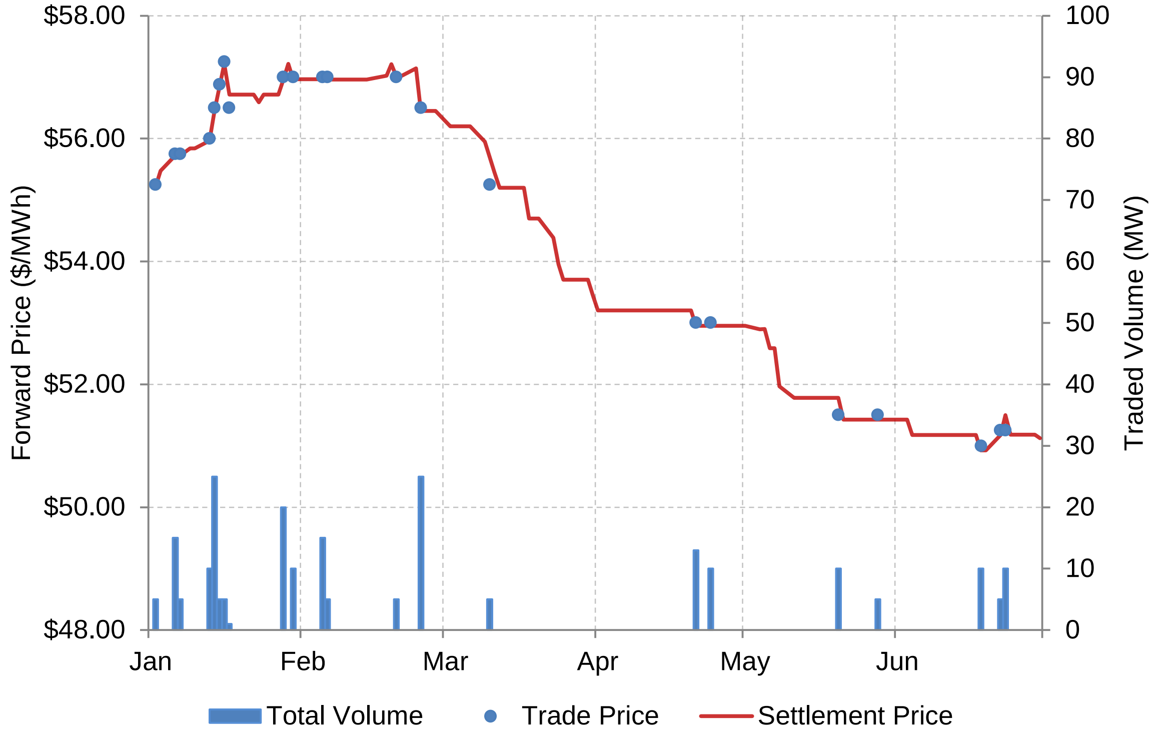
* The RRO full load volumes are estimated based on average expected block sizes

3.2 Trading of annual products

Figure 22 shows how the Calendar 2021 (CAL21) flat contract has traded over the course of 2020 year-to-date. 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. Since then, the price of the CAL21 flat contract has fallen by 10.1% to $51.25/MWh as of June 23. This suggests that forward traders anticipate that the recently observed decrease in demand compared to prior expectations of the future will persist into 2021.

The bars in Figure 22 show the daily amount of traded volume of the CAL21 flat contract. Trading of the CAL21 flat contract has been very limited since early March; for example, the contract did not trade for over a month between March 10 and April 21. Trading volumes of the CAL21 flat contract have been low, much lower than is normally the case for the prompt year. The traded volume for the CAL21 flat contract in Q1 and Q2 of 2020 was 219 MW compared with 686 MW for the CAL20 flat contract over the first half of 2019, a decline of 68%.

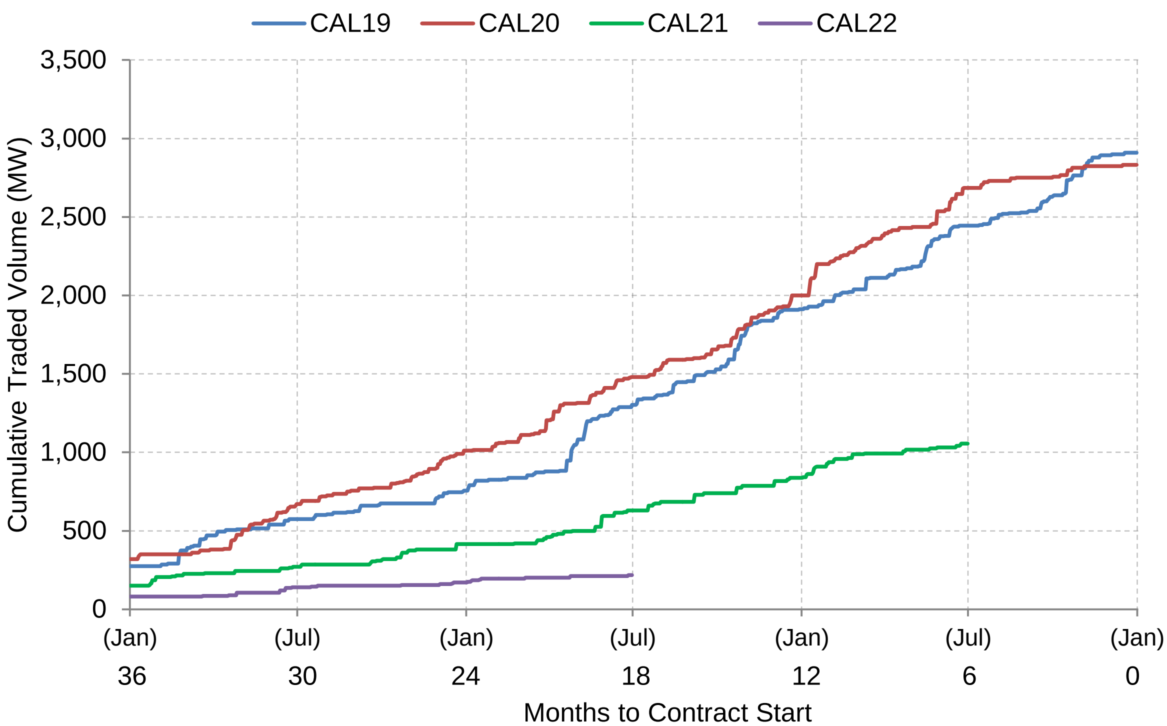
Figure 22: Forward prices and traded volumes of the CAL21 flat contract (January 1 to June 30, 2020)



Given the low liquidity of the CAL21 flat contract, Figure 22 displays the NGX settlement price, which is determined by the NGX based on bids and offers for the contract, in addition to the transacted price of executed trades. As shown, the settlement price of the CAL21 flat contract declined in March by 5.3%, was stable in April, and declined by 2.9% in May.

Figure 23 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 at that time. 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 since 30 months prior to contract start (July 2018). The traded volumes for the CAL22 flat contract are also low.

Figure 23: Traded volumes for flat calendar contracts (3 years prior to contract start)[34]



Currently there are six coal-fired generators in Alberta that are subject to three Power Purchase Arrangements (PPAs). Under these PPAs, which are listed in Table 12, offer control over the bulk of the associated generation capacity is held by the Balancing Pool (a public agency). These PPAs, as well as the Hydro PPA, expire at the end of 2020, which will result in offer control fully reverting to the owner of the generator (all which are commercial entities). This long-anticipated return of control of generation assets to commercial entities is important for the continued success of Alberta's competitive generation market, including market efficiency, price formation, and continued funding from investors for new and existing generation capacity in Alberta.

Table 12: Coal PPAs scheduled to expire at the end of 2020

Assets	Capacity (MW)	Owner
Genesee 1/2	800	Capital Power
Keephills 1/2	790	TransAlta
Sheerness 1/2	790	Heartland (50%) TransAlta Cogeneration (50%)

[34] Uses trade data going back to January 1, 2014 and up to and including June 30, 2020.

As a result of these changes, trading of the CAL21 flat contract is particularly important. This is because the power pool prices that will eventually be used to settle this contract will all be determined after the PPAs expire and the associated generation capacity is offered to the market by commercial entities. The MSA is of the view that uncertainty over the specific nature of the offer strategies that will be implemented by the commercial entities, as well as changes to the dynamics of the COVID-19 pandemic and global energy markets, increase the difficulty and uncertainty faced by forward traders in forming expectations of power pool prices in 2021 (and beyond). The MSA is of the view that these are important factors in explaining the substantial reduction in observed trading volumes of the CAL21 flat contract (as discussed above, there have been more moderate declines in trading of near-term monthly products as well).

The MSA is of the view that liquid forward markets contribute to the success of the Alberta electricity market and wants to more fully understand the reasons for reduced forward market liquidity. The MSA will be reaching out to forward market participants in the coming weeks to better understand whether market participants share these views and can shed further light on the causes of this decline.

Notwithstanding the above, with the return of offer control currently subject to PPAs to commercial entities, the MSA is of the view that the Alberta electricity market will remain competitive and serve the interests of Albertans. It is likely that energy prices will be somewhat higher in future years than in the recent past, consistent with fair, efficient, and openly competitive market outcomes and the need for market prices in an energy-only market to cover the full cost of prudently made investments over time.

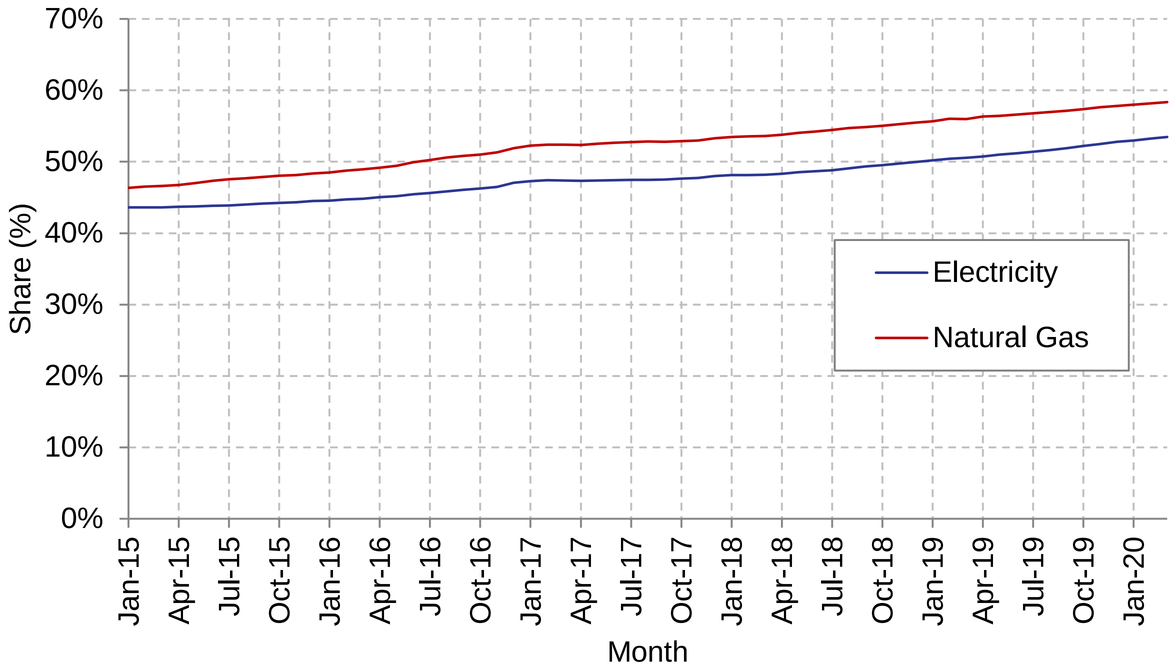
As part of its ongoing surveillance and reporting activities, the MSA is focused on ensuring fair, efficient, and open competition in Alberta's electricity market and will report publicly, as well as take appropriate enforcement action, in relation to any observed deviations from this standard or other applicable rules.

4 THE RETAIL MARKETS

4.1 Competitive market shares

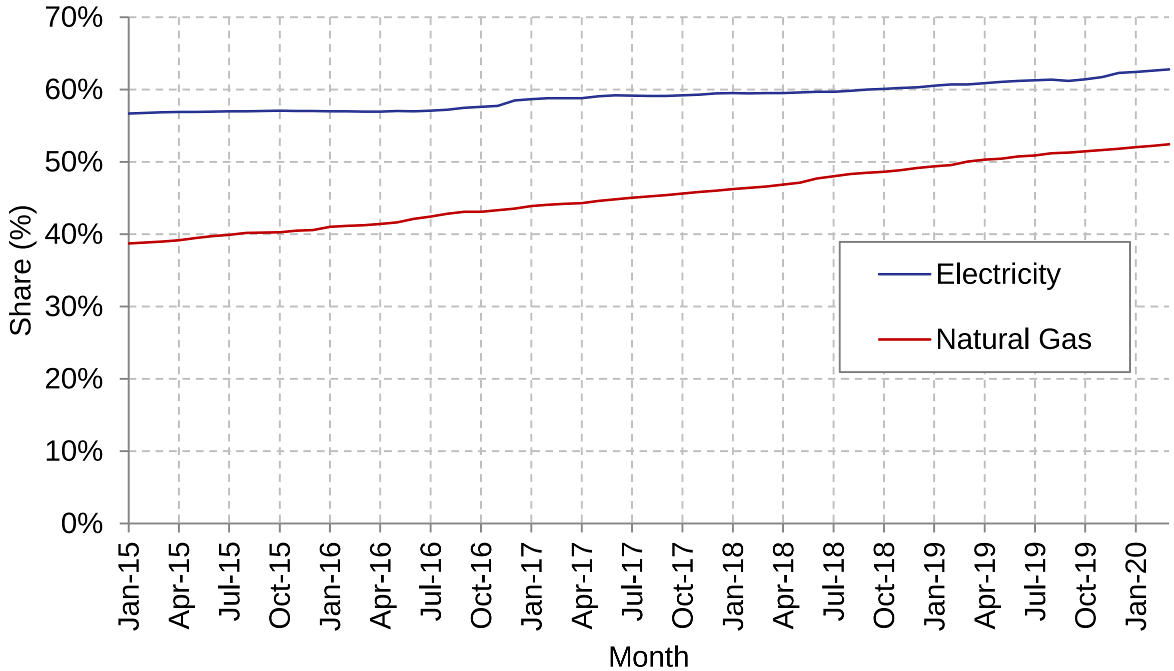
The share of residential customers on competitive retail electricity and natural gas contracts continued to increase over Q1/2020 (Figure 24). Competitive market shares for both contracts typically trend together owing to the popularity of dual-fuel contracts among residential customers.

Figure 24: Share of residential customers on competitive retail contracts, January 2015 to March 2020



A greater share of commercial customers is on competitive electricity contracts compared with residential customers, but fewer have switched to competitive natural gas providers (Figure 25).

Figure 25: Share of commercial customers on competitive retail contracts, January 2015 to March 2020

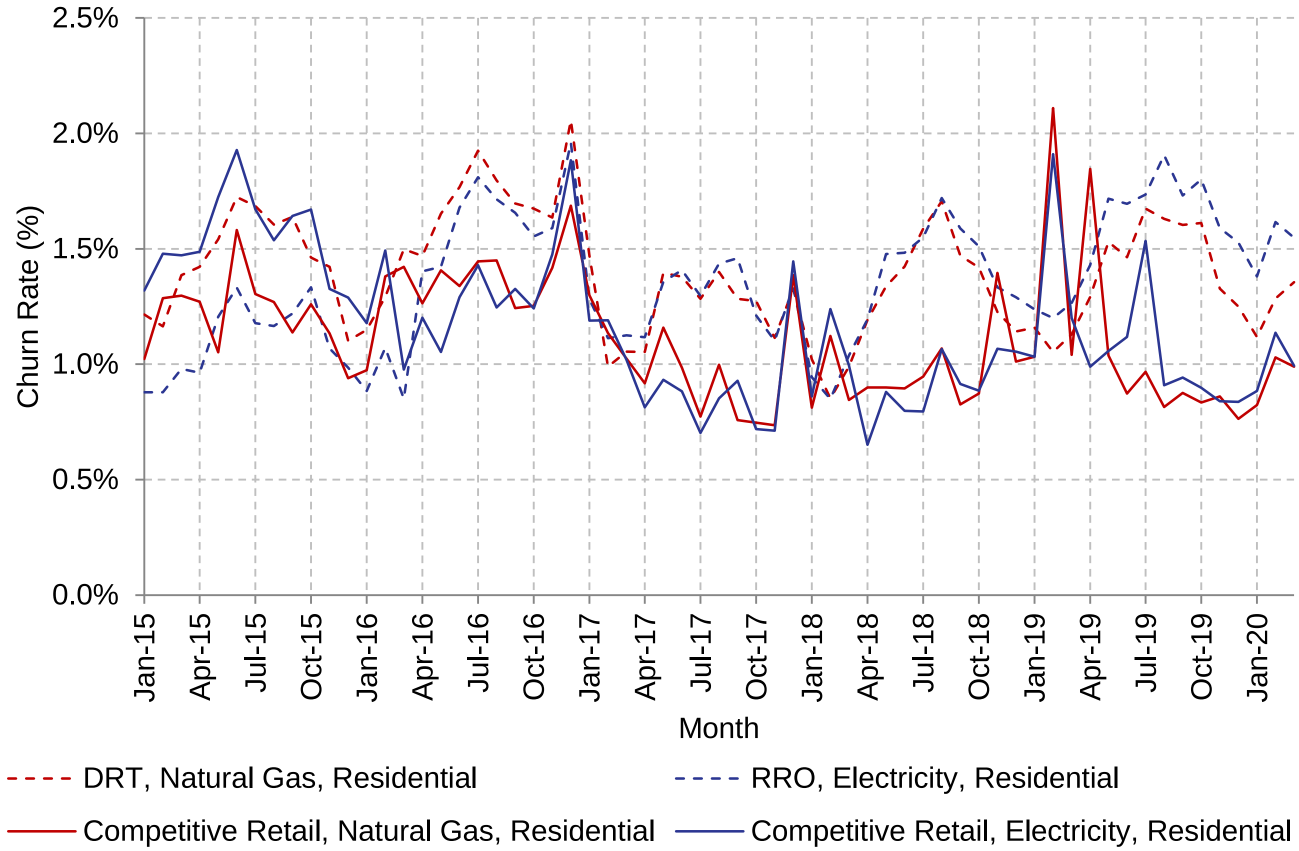


4.2 Churn

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 (Figure 26), 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.

Figure 26: Retail churn rates, residential customers, January 2015 to March 2020



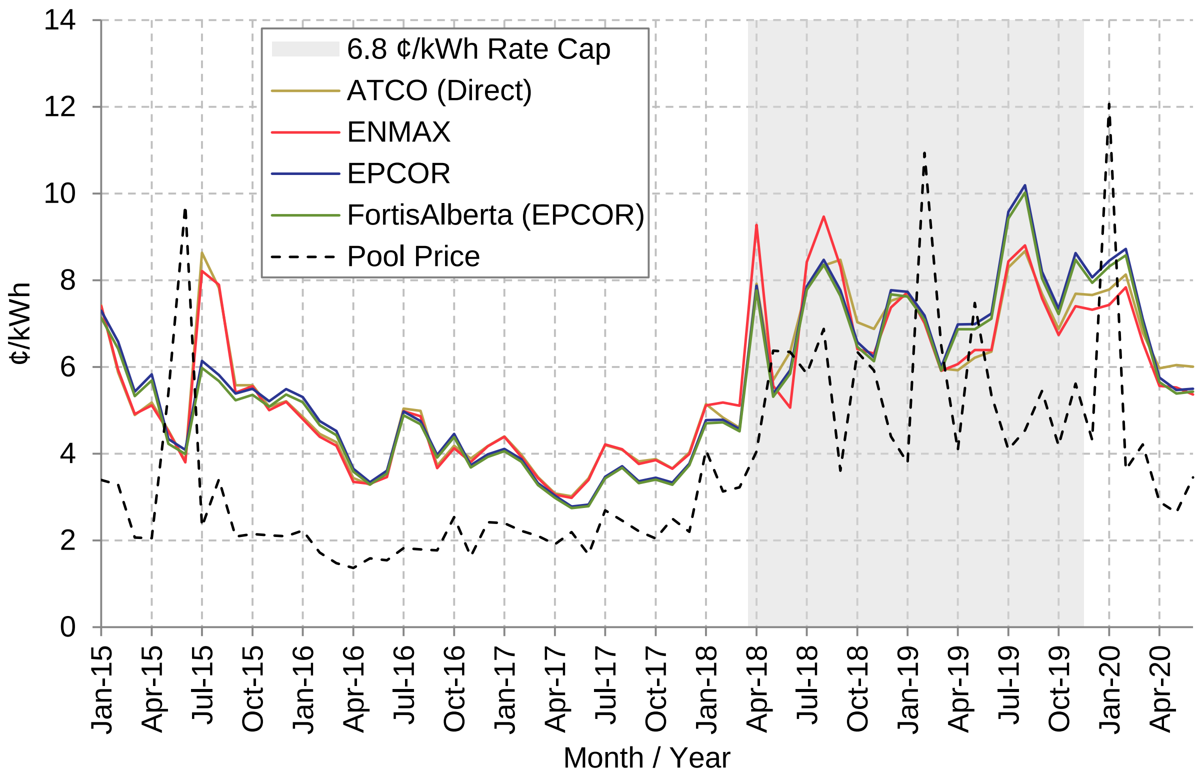
4.3 Regulated retail market

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 5.64 ¢/kWh in the four largest distribution service areas in Q2 2020, a 2 ¢/kWh decrease compared to the previous quarter (Figure 27). This decrease was a direct result of the decrease in forward prices for Q2 2020 monthly products that began in March. Q2 2020 RRO rates were comparable to some of the lowest RRO rates set in the two years prior.

Figure 27: (Uncapped) Residential RRO rates, January 2015 to June 2020[35]

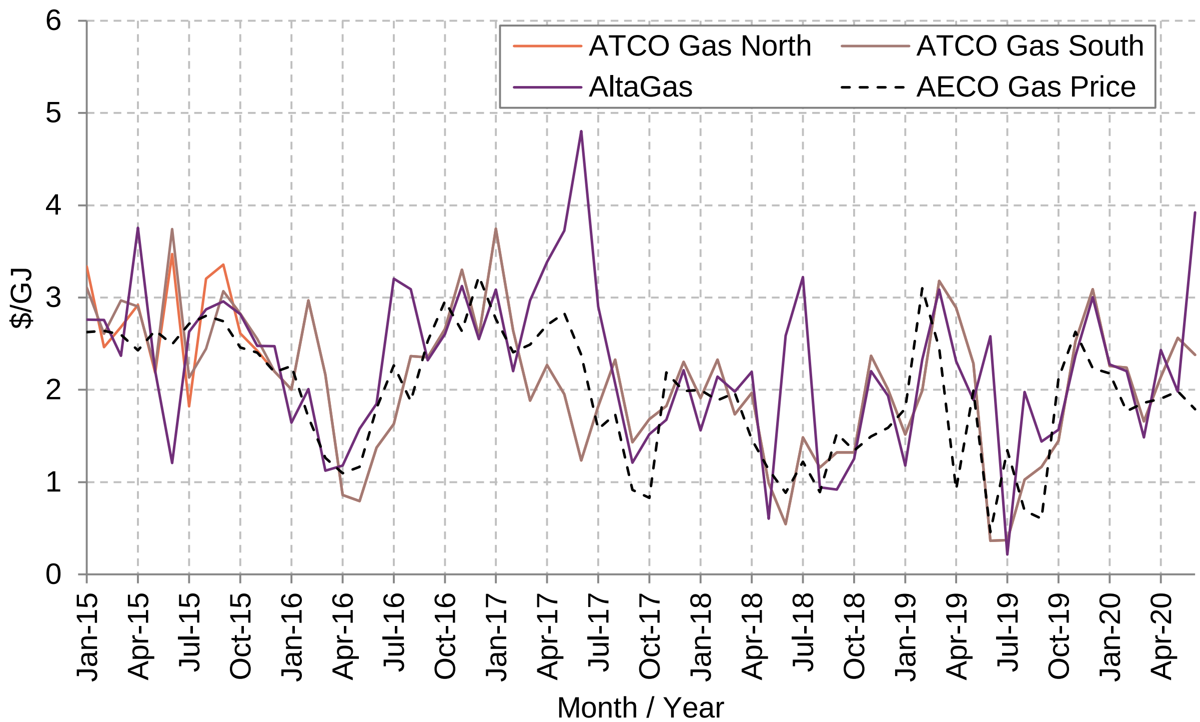


4.3.2 Default Rate Tariff (DRT)

Average DRT rates increased to \$2.50/GJ in Q2 2020, up from \$2.03/GJ the previous quarter (Figure 28). Some of this increase was attributable to a significant increase in the AltaGas Utilities rate in June 2020. Wholesale natural gas prices have generally fallen since the beginning of the year.

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

Figure 28: DRT Rates, January 2015 to June 2020



4.4 90-day utility cost deferral program

On March 17, 2020 the Government of Alberta announced a 90-day utility payment deferral program to assist Albertans through the COVID-19 pandemic. Consumers eligible for the RRO (for electricity services) or DRT (for natural gas services) could enroll by applying directly to their retailers. The applicants had utility bills between March 18 and June 18, 2020 deferred. Also, in that period customers could not be cut off from service or have any collections action made against them.

Some 350,000 customers enrolled in the program. These customers will be required to repay the deferred payments in equal monthly installments or through an agreed-upon repayment plan over the June 19, 2020 to June 18, 2021 repayment period.

The MSA is responsible for investigating contraventions of the *Utility Payment Deferral Program Act* that formally established the utility payment deferral program. Under the program, electricity retailers could apply to the AUC for funding from the Balancing Pool to recover deferred bill payments, while natural gas retailers could recover deferred payments from the Government of Alberta following an application to the AUC. Funding provided to retailers is to be remitted over the repayment period.

5 ISSUE ASSESSMENTS AND INVESTIGATIONS

5.1 Publication of coal offer data

On September 16, 2019, the AESO posted to its website the price, quantity, and asset identification of offers from coal generators made to the power pool that were available for dispatch between September 1, 2009 and August 31, 2019.

Section 6 of the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation) requires the AESO to publish price and quantity information associated with each offer made to the power pool that is available for dispatch. However, the AESO cannot make asset identification and the identification of the electricity market participant related to the offers public until 60 days after the settlement interval to which the offer applied. Thus, the publication of the coal offer information contravenes section 6 of the FEOC Regulation.

The MSA decided not to proceed to an investigation as the publication of the coal offer price information did not in this instance undermine the fair, efficient, and openly competitive operation of the electricity market and had no adverse effect on the economic operation of the interconnected electric system.

5.2 Complaints regarding outages in January 2020

The MSA received two complaints regarding market participant behaviour associated with high pool prices observed in January 2020.

The MSA examined 15 outages that occurred in January 2020 to assess whether any of these outages were deliberately taken by the operators in order to physically withhold their assets and increase pool prices. Specific attention was paid to six outages that occurred between January 11 and 17, when pool prices were significantly higher than at other times in the month.

The MSA concluded that there was insufficient evidence to support proceeding to investigation regarding physical withholding in January 2020.

5.3 Self-report regarding ISO rule 501.10

In February 2020, the AESO submitted a self-report regarding a contravention of ISO rule 501.10, *Transmission Loss Factors.* The AESO provided system access service to a market participant with a contract capacity of 0 MW that was excluded from the 2019 Loss Factor calculation. This contravenes ISO rule 501.10.

The MSA decided not to investigate the matter as the economic impact of the error was minor and was fully resolved by the AESO. Further, the MSA found that AESO took measures to ensure that 0 MW contract capacity locations are identified in the future.

5.4 Self-report regarding disclosure of and trading on non-public outage information

In August 2019, the MSA received a self-report whereby a market participant shared non-public outage information with its agent while requesting a forward hedge for the outage period. The agent in turn shared the non-public outage information with potential sellers while requesting a quote for a trade in the forward electricity market. The agent self-reported the incident as a potential contravention of sections 3(1) and 4 of the FEOC Regulation.

In this case, there was no impact on the wholesale electricity market resulting from the sharing of the information and the incident was not a part of a recurring problem. Given the circumstances in this case, the MSA declined to investigate.

Notwithstanding the decision to take no investigative action in this case, the MSA noted that communication protocols could be improved between the parties involved in this incident. Further, market participants are reminded that they should have procedures in place to prevent the disclosure of and/or trading on non-public outage information.

5.5 Self-reports related to sharing of dispatch information

In Q2 2020, the MSA received two self-reports of contraventions of section 3 of the FEOC Regulation. The two events occurred in March and April, respectively. In both instances, an agent disseminated asset dispatch information for an asset to the wrong asset operator not affiliated with the owner of the dispatched asset.

These events are contraventions of the FEOC Regulation as the agent does not have an AUC Order under section 3(3) of the FEOC Regulation to share dispatch information related to an asset with a market participant that is not related to the owner of the asset. In both cases, the MSA decided to not proceed to an investigation as there was no impact on the wholesale electricity market from the sharing of the information.

Further, the contraventions appeared to have occurred due to precautions taken as a result of COVID-19. In this particular instance the MSA spoke with the agent to examine whether additional technical controls would help prevent similar future occurrences.

5.6 Assessment of possible wash trading

During the quarter the MSA concluded an issue assessment on potential wash trading that occurred in Q1 of 2020. This issue was identified as a result of the MSA's ongoing internal monitoring of the Alberta electricity market. While the MSA found that the trading pattern was unusual, no evidence was found to support a finding of impermissible wash trading as set out under subsection 2(c) of the FEOC Regulation.

5.7 AESO loss factors publication

Under ISO rule 501.10, *Transmission Loss Factors*, the AESO is obligated to publish final loss factor values for a given calendar year no later than the fifth business day in November of the previous calendar year. Between November 16, 2018 and January 16, 2019, the AESO self-reported five breaches of ISO rule 501.10 for the years 2017, 2018, and 2019.

On April 26, 2019, the MSA issued a Notice of Investigation to the AESO. The MSA and AESO met on May 8, 2019 to discuss the timeline and scope of the investigation. In a letter to the MSA on May 10, 2019, the AESO committed to publish (i) 2019 loss factors by June 30, 2019, (ii) 2018 loss factors by December 31, 2019, and (iii) 2017 loss factors by March 31, 2020.

By letter dated May 24, 2019, the MSA placed the investigation in abeyance pending the AESO publishing loss factors on the schedule committed to by the AESO.

The AESO has satisfied all of the agreed deadlines. As a result, on April 28, 2020, the MSA informed the AESO that this investigation is now closed.

6 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 June 30, 2020 the MSA closed 178 ISO rules compliance matters, as reported in Table 13.[36] An additional 82 matters were carried forward to the next quarter. During this period 61 matters were addressed with notices of specified penalty, totaling $113,750 in financial penalties, with details provided in Table 14.

Table 13: ISO rules compliance outcomes for matters closed from January 1 to June 30, 2020

Section of ISO Rules	Forbearance	Notice of Specified Penalty	No Breach
103.1	1	-	-
201.4	-	1	-
201.7	16	6	1
203.3	17	17	2
203.4	24	10	6
203.6	5	1	-
204.3	1	-	-
205.3	2	5	-
205.4	21	-	-
205.5	3	5	1
205.6	3	11	-
303.1	1	-	-
304.9	10	-	-
306.4	1	2	-
306.5	-	3	-
306.7	-	-	1
505.4	1	-	-
Total	**106**	**61**	**11**

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

The sections of the ISO rules listed in Table 13 and Table 14 fall into the following categories:

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

Table 14: Specified penalties issued between January 1, 2020 and June 30, 2020 for contraventions of the ISO rules

Market Participant	Total Specified Penalty Amounts by Section of the ISO Rules ($)										Total ($)	Matters Addressed with a Penalty
	201.4	201.7	203.3	203.4	203.6	205.3	205.5	205.6	306.4	306.5		
Air Liquide Canada Inc.	500										500	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.								2,500			2,500	1
Calgary Energy Centre No. 2 Inc.			3,750								3,750	2
Canadian Natural Resources Ltd.			1,500	1,500							3,000	2
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
Powerex Corp.		3,250									3,250	2
TransAlta Corporation			4,000								4,000	5
TransAlta Generation Partnership			4,000	750		3,000	12,000	2,000			21,750	13
Voltus Energy Canada Ltd.								10,000			10,000	2
WCSB GP III Ltd.			1,500								1,500	1
Total	500	5,250	35,000	20,000	750	3,500	12,250	33,500	500	2,500	113,750	61

7 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.

AUC Rule 027 requires the MSA to report publicly with respect to all compliance breaches, whether they are CIP ARS or O&P ARS. However, CIP matters often deal with cyber security issues and there is a growing concern in both Canada and the United States that broad public reporting creates a security risk in itself. In the United States, the Federal Energy Regulatory Commission (FERC) currently has a proceeding underway to address this very issue. The MSA has raised this concern with both the AESO and the AUC. Until the MSA receives direction from the AUC regarding CIP reporting, the MSA will continue to refrain from publishing CIP statistics.

From January 1 to June 30, 2020 the MSA closed 24 ARS O&P compliance matters, as reported in Table 15.[37] An additional 96 matters were carried forward to the next quarter. During this period, six matters were addressed with notices of specified penalty, totaling $17,500 in financial penalties, with details provided in Table 16.

[37] An ARS matter is considered closed once a disposition has been issued and mitigation (where applicable) is complete.

Table 15: Outcomes for O&P ARS matters closed between January 1 and June 30, 2020

Reliability Standard	Forbearance	Notice of Specified Penalty	No Breach
BAL-005	2	-	-
COM-001	-	-	1
COM-002	-	-	2
EOP-001	1	-	-
INT-009	2	-	-
PRC-001	4	2	-
PRC-018	-	1	-
PRC-023	1	-	-
VAR-002	3	3	-
VAR-501-WECC	2	-	-
Total	15	6	3

Table 16: Specified penalties for matters closed between January 1, 2020 and June 30, 2020 for contraventions of O&P ARS

Market Participant	Total Specified Penalty Amounts by ARS ($)			Total ($)	Matters Addressed with a Penalty
	PRC-001	PRC-018	VAR-002		
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
Total	7,500	250	9,750	17,500	6

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

8 OTHER ACTIVIES

8.1 MSA enforcement statement related to economic withholding

On June 29, 2020, the MSA issued a public notice[38] and Enforcement Statement[39] that set out its approach to economic withholding in the Alberta electricity market. In the public notice, the MSA indicated that if market participants or stakeholders had any questions or comments regarding the Enforcement Statement, or were of the view that the MSA should develop guidelines related to economic withholding or offer behaviour more broadly, feedback would be welcome.

No feedback requesting additional action by the MSA has been received and, as a result, the MSA will not proceed to develop guidelines or undertake any other related work.

8.2 Public consultation regarding the MSA's Compliance Process

On August 7, 2020, the MSA issued a public notice[40] 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. Additional detail is in the notice.

Concurrently, the MSA indicated that clarifying certain issues related to the publication of notices of specified penalties regarding contraventions of the CIP reliability standards was the only outstanding are of interest to the MSA regarding amendments to AUC Rule 027.

8.3 Red Tape Reduction measures

The MSA has developed a two-phase approach to reducing red tape in 2020. In the first phase, on June 30 a number of non-material changes were made to the MSA's Compliance Process.

In the second phase, more substantial reforms will be proposed as part of the public consultation regarding the MSA's Compliance Process that will begin in September. The MSA is required by the *Market Surveillance Regulation* to consult publicly on the second phase of changes as they are likely to be material in nature.

[38] MSA Public Notice: Re: MSA Enforcement statement related to economic withholding (June 29, 2020)

[39] MSA Enforcement Statement: Economic Withholding (June 29, 2020)

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