MARKET SURVEILLANCE
ADMINISTRATOR

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NOTICE TO PARTICIPANTS AND STAKEHOLDERS

May 14, 2020

Re: MSA Quarterly Reporting

For many years the MSA made public a quarterly report that provided an overview of:

- recent outcomes Alberta's electricity and retail natural gas markets,
- analysis of these market outcomes,
- a summary of the MSA's recently completed investigations and issue assessments, and
- an update on the MSA's compliance activities in the quarter.

Following a brief hiatus, the MSA will resume publication of Quarterly Reports. To this end, the MSA's "Quarterly Report for Q1 2020" is being made public today.

With the resumption of these Quarterly Reports, the MSA will be focusing its efforts on market surveillance and enforcement (including compliance), while deemphasizing regulatory and high-level market design work. That focus will be evident in this Quarterly Report.

Going forward, the MSA will aim to publish its Quarterly Report within six weeks of the end of each quarter.

The MSA welcomes comments about its Quarterly Reports, including the scope of its coverage, at stakeholderconsultation@albertamsa.ca.

Sincerely,

Derek Olmstead
Market Surveillance Administrator

MARKET SURVEILLANCE
ADMINISTRATOR

Quarterly Report for Q1 2020

May 14, 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 Q1 2020.

- The average pool price in the quarter was similar to that in the same quarter of 2019. Pool prices ranged from $30/MWh to $40/MWh in 63% of the hours in the quarter, which is approximately equal to the marginal cost of production from coal-fired generation capacity (including the cost of carbon emissions, which is the largest component of costs for coal-fired generators). There were no hours where pool price was less than $15/MWh and there were only six hours where pool price was less than $20/MWh.

- Unlike in Q1 2019, when pool prices were higher than average across a large number of days in February and March, higher pool prices in Q1 2020 were concentrated in an extremely cold week in January and a short period in March.

- The total cost of operating reserves was 24% higher than the same quarter the previous year. The cost of active reserves in the period of extremely cold weather in January was a significant driver; costs outside this week were considerably lower.

- Recent changes to one of the main Energy Price Setting Plans used to set retail prices for the electricity customers on the Regulated Rate Option have resulted in a partial shift away from the procurement of standard monthly products to full-load contracts. This shift in procurement may have reduced the traded volumes of standard monthly forward products, although it will have shifted liquidity to non-standard products.

- The share of residential customers on competitive contracts has increased at a steady but relatively slow rate for many years. The cap on RRO rates came into effect in 2017 and continued until late 2019 appears to have had little effect on the rate of switching towards competitive contracts.

- The MSA finalised issue assessments / investigations: one was related to the AESO's publication of historical loss factors and two were related to self-reports regarding disclosure and trading on non-public outage information.

- The MSA addressed 77 ISO rules compliance matters; 27 matters were addressed with notices of specified penalty.

- The MSA addressed 12 Alberta Reliability Standards Operations and Planning compliance matters; three matters were addressed with notices of specified penalties.

1 THE POWER POOL

1.1 Summary

The overall price level in the Alberta market indicates the power pool was competitive in Q1 2020. Market summary statistics for the quarter are reported in Table 1.

The average pool price in the quarter was similar to that in the same quarter of 2019. Pool prices ranged from $30/MWh to $40/MWh in 63% of the hours in the quarter, which is approximately equal to the marginal cost of production from coal-fired generation capacity (including the cost of carbon emissions, which is the largest component of costs for coal-fired generators).

There were no hours where pool price was less than $15/MWh and there were only six hours where pool price was less than $20/MWh.

Unlike in Q1 2019, when pool prices were higher than average across a large number of days in February and March, higher pool prices in Q1 2020 were concentrated in an extremely cold week in January and a short period in March.

Table 1: Market Summary

		2019	**2020**	***Change***
Pool price (avg $/MWh)	Jan	37.83	120.67	*219%*
	Feb	109.36	36.33	*-67%*
	Mar	65.04	42.16	*-35%*
	Q1	**69.46**	**67.06**	***-3%***
Demand (AIL, total GWh)	Jan	7,669	7,824	*2%*
	Feb	7,183	7,105	*-1%*
	Mar	7,370	7,436	*1%*
	Q1	**22,222**	**22,365**	***1%***
Gas price (avg $/GJ)	Jan	1.82	2.17	*19%*
	Feb	3.07	1.76	*-43%*
	Mar	2.43	1.86	*-24%*
	Q1	**2.42**	**1.93**	***-20%***
Wind (total GWh)	Jan	476	549	*15%*
	Feb	175	568	*224%*
	Mar	266	521	*96%*
	Q1	**918**	**1,638**	***79%***
Net exports (total GWh)	Jan	-10	-363	*3,425%*
	Feb	66	-338	*-611%*
	Mar	92	-331	*-461%*
	Q1	**148**	**-1,032**	***-799%***
Supply cushion (avg MW)	Jan	1,598	1,609	*1%*
	Feb	1,008	1,755	*74%*
	Mar	1,370	1,482	*8%*
	Q1	**1,336**	**1,612**	***21%***

1.2 Market outcomes

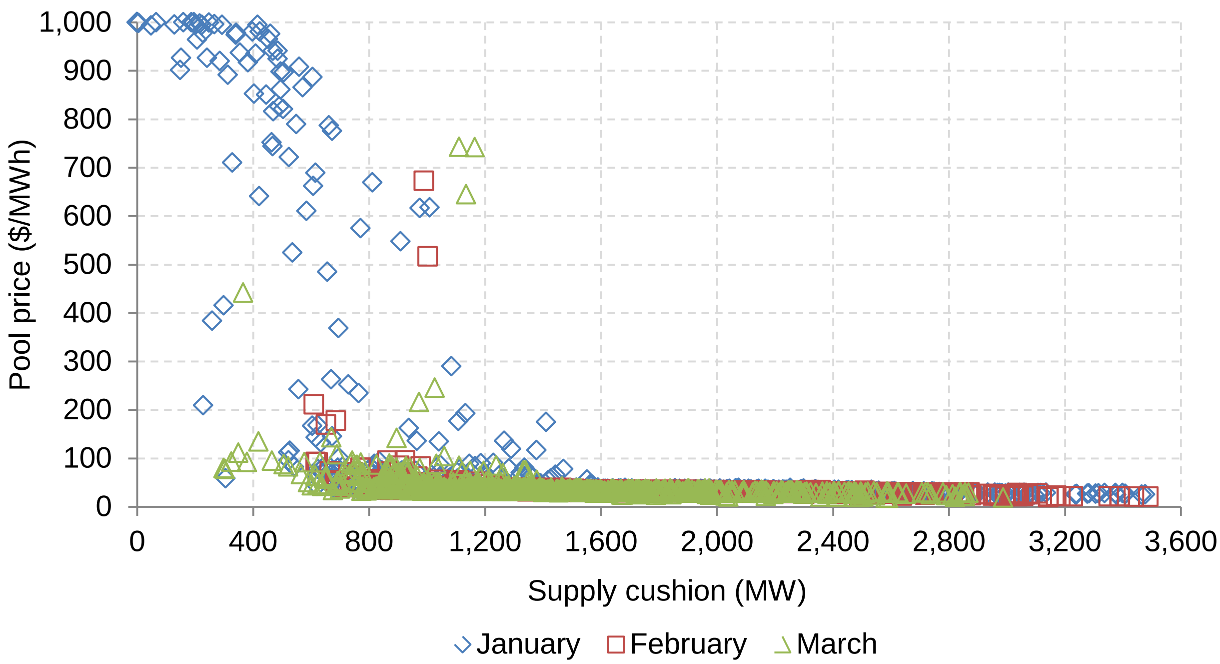
It is expected in general that the supply cushion will be inversely correlated with the pool price; that is, that the pool price will decrease as the supply cushion increases. Figure 1 illustrates the hourly supply cushion and pool price for each hour in the quarter.[1] These market outcomes are generally consistent with expectations. In particular, the market was well-supplied in most hours and the pool price was in the vicinity of marginal cost in most hours. The high pool prices in January occurred at both very low supply cushion levels and during extremely cold weather (which are related conditions).

[1] The 'supply cushion' is a summary measure of supply-demand conditions in the market and is defined here as the quantity of available but not dispatched capacity in the energy market merit order.

These pricing outcomes, in the form of high payments for delivered power, provided extremely strong incentives for generation capacity to be available when it was most valuable to consumers. These high prices were not paid to generation capacity that was unavailable at the time. Overall, these market outcomes are consistent with a competitive market under very high demand and limited supply conditions.

The sections that follow discuss market outcomes in January and March in further detail.

Figure 1: Hourly pool price and supply cushion



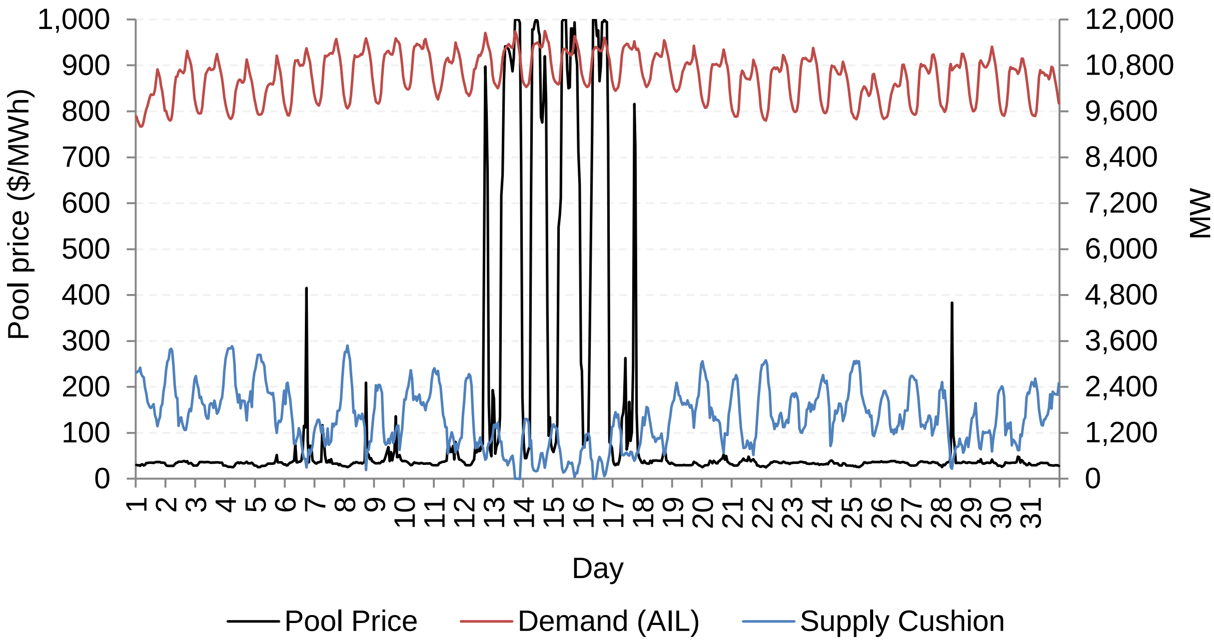
1.2.1 January 2020

The average pool price in January 2020 was $120.67/MWh. The hourly pool price, demand, and supply cushion for each hour in January is illustrated in Figure 2.

While most pool prices in January were relatively low, there was a sequence of high pool price hours in the period from January 12 to 17 (Cold Week). This period coincided with extreme low temperatures throughout the province which resulted in higher demand and outages at some generation facilities. A new record high demand was set during this period on January 14 in hour-ending 18 at 11,698 MW; the pool price in this hour was $919.63/MWh. January 15 was, in nominal terms, the highest ever average pool price day in the Alberta power pool ($674.72/MWh).

The high demand and limited supply during this period resulted in the AESO issuing two energy emergency alerts (EEA). One of these alerts escalated to an EEA2 event on January 13 from hour-ending 18 to 22 and the other was an EEA1 event that occurred on January 16 in hour-ending 9.

Figure 2: Hourly pool price, demand, and supply cushion, January 2020



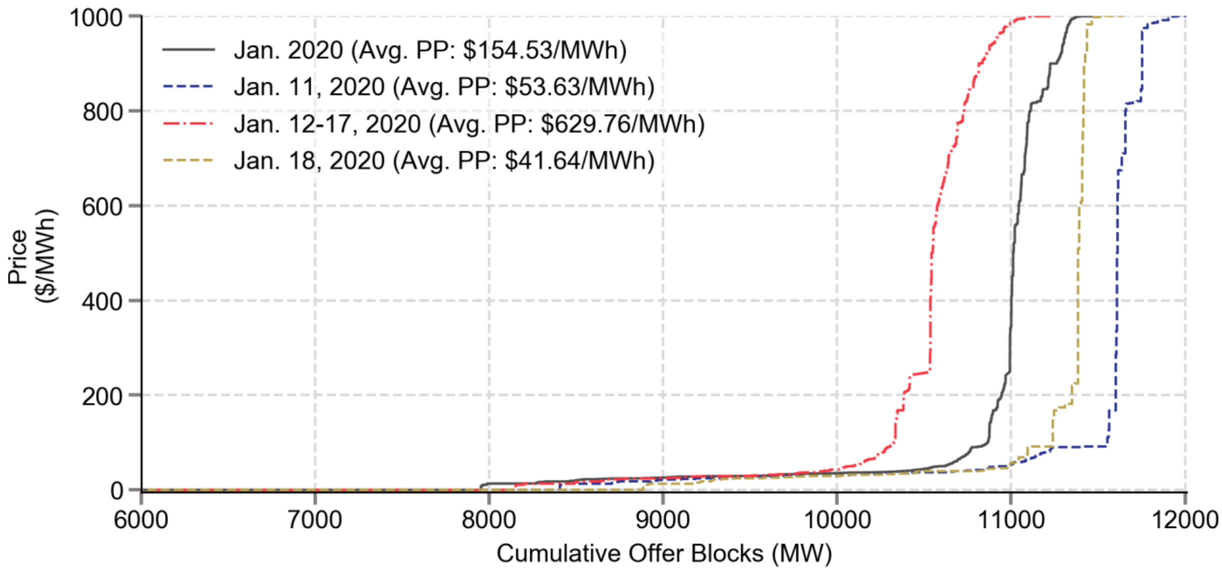
The market supply curve in a given delivery hour indicates, for each price between the offer price floor of $0/MWh and the offer price cap of $999.99/MWh, the cumulative volume of offers made to the market at prices less than or equal to that price. An average market supply curve is calculated by finding the average quantity of offers made at each price for some set of delivery hours.

In the Alberta power pool, the shape of the market supply curve is generally characterized by greater than half the total quantity of offers being made at $0/MWh (often reflecting must-run conditions), most of the rest of the offers being at or around short-run marginal cost (mostly in the $15/MWh to $40/MWh range), and finally up to 1,000 MW of offers being made at prices above short-run marginal cost or at high levels of opportunity cost. Reductions in supply, say, due to outages or reduced imports, result in the market supply curve shifting to the leftward. Increases in the offer prices of supply, all else equal, result in the market supply curve shifting upward.

Figure 3 illustrates four on-peak average market supply curves for January 2020, focusing on the following periods:

- All days in January;
- Saturday, January 11 (the day before the Cold Week);
- Sunday, January 12 to Friday, January 17 (the Cold Week); and
- Saturday, January 18 (the day after the Cold Week).

Figure 3: On-peak average market supply curves, January 2020[2]



As illustrated in the figure, the total supply for the Cold Week decreased by approximately 800 MW (and the average market supply curve shifted to the left) compared to the Saturday immediately preceding the week. On the day following this week, total supply increased by approximately 400 MW (and the average market supply curve shifted back to the right). As such, these average market supply curves illustrate a reduction in supply, including unexpected outages, during the Cold Week. This decrease in supply is considered in further detail below.

Furthermore, the average market supply curve during the Cold Week is flatter (more price elastic) compared to the days immediately before and after the week. In particular, there was a meaningful amount of generation offered at prices around $250/MWh and a significant amount offered at prices above short-run marginal cost.

Regarding the extremely cold weather itself, as illustrated in Figure 4, the average temperature in Alberta during the Cold Week was -28°C. As indicated above, extreme temperatures can influence generating unit availability. In this case, the availability of natural gas and natural gas cogeneration was similar during the Cold Week to what it was in the rest of the month. However, during the Cold Week, the availability of coal-fired generation decreased, with significant outages experienced at the GN1, KH2, KH3, SD4, and SH2 facilities throughout the week. Also, wind generation during the week was extremely low, which is not an uncommon observation, but was frequently much higher in other parts of the month.[3]

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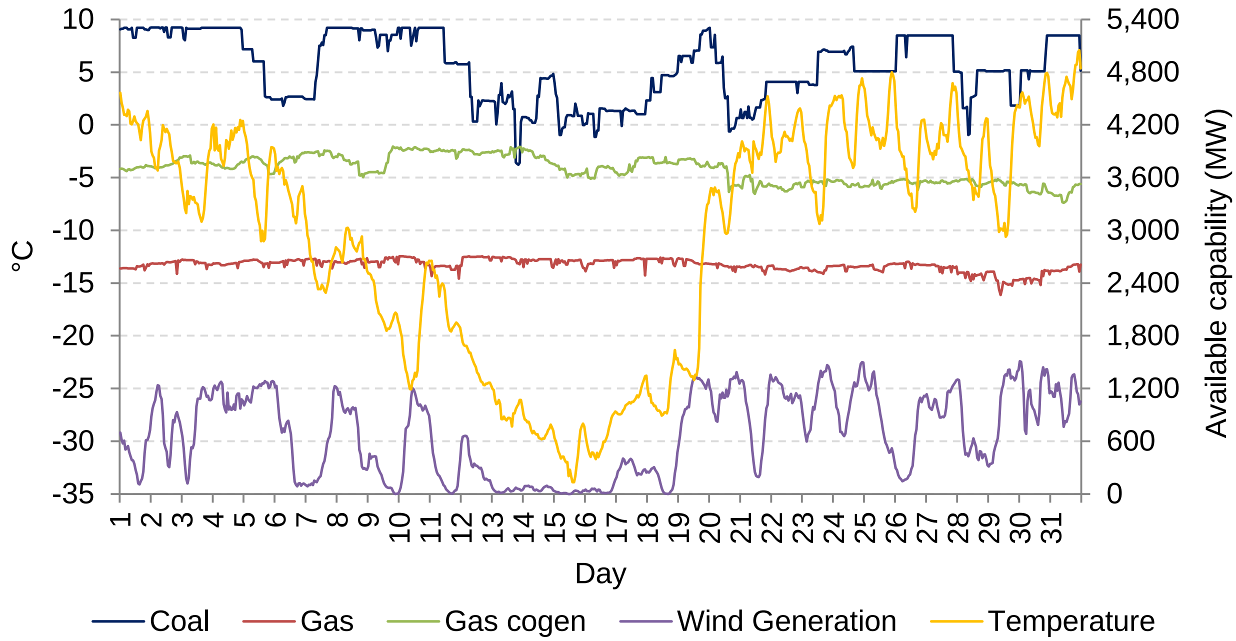
[2] On-peak delivery hours are defined as hour-ending 8 through 23. Off-peak delivery hours are defined as all other delivery hours.

[3] The MSA considered the relationship between wind generation and temperature in greater detail in its Q1 2019 Quarterly Report, page 6-7.

Figure 4: Generator availability by fuel type and average hourly temperature, January 2020[4]



As illustrated in Figure 5, during the Cold Week the available transfer capability (ATC) on the BC/MATL intertie (that connects Alberta to British Columbia and Montana) was fully utilized for imports. This is the market outcome that is expected since high prices in Alberta relative to those in neighbouring markets is anticipated to incentivise traders to schedule imports to Alberta from neighbouring markets.

The utilization of the smaller intertie that connects Alberta to Saskatchewan was more variable in January. This is not unexpected because instances of extreme cold weather in Alberta are highly correlated similar instances in Saskatchewan.

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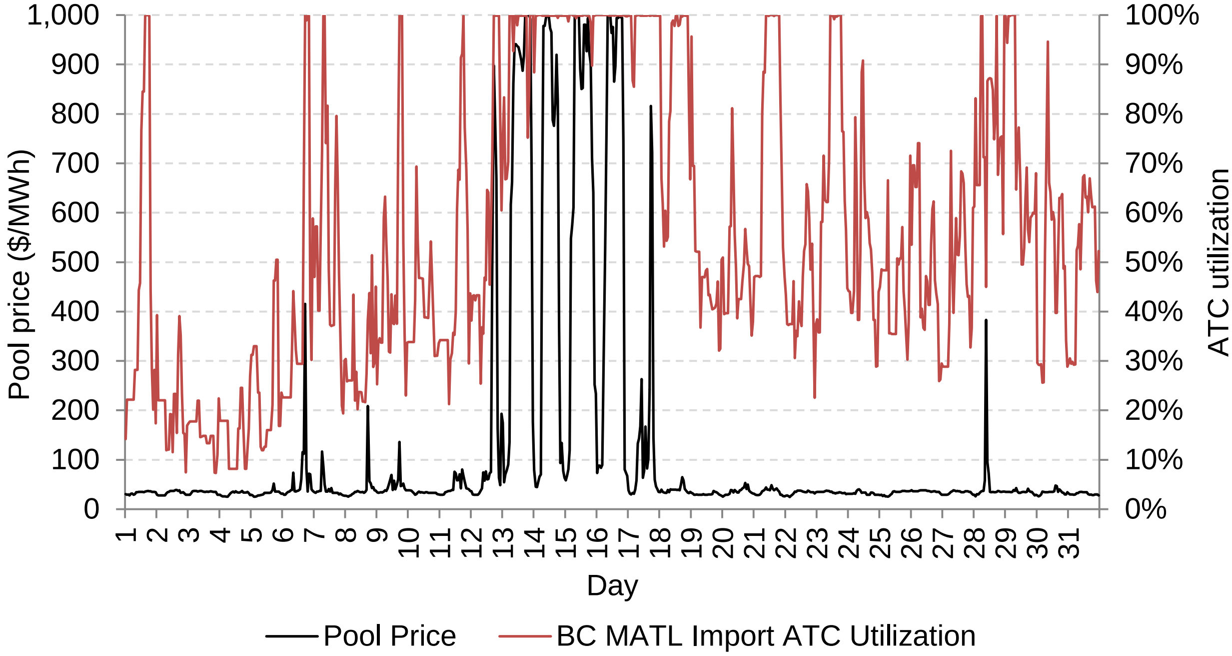
[4] Average hourly temperatures in Alberta are calculated as the average temperature in Calgary, Edmonton, Fort McMurray, and Lethbridge.

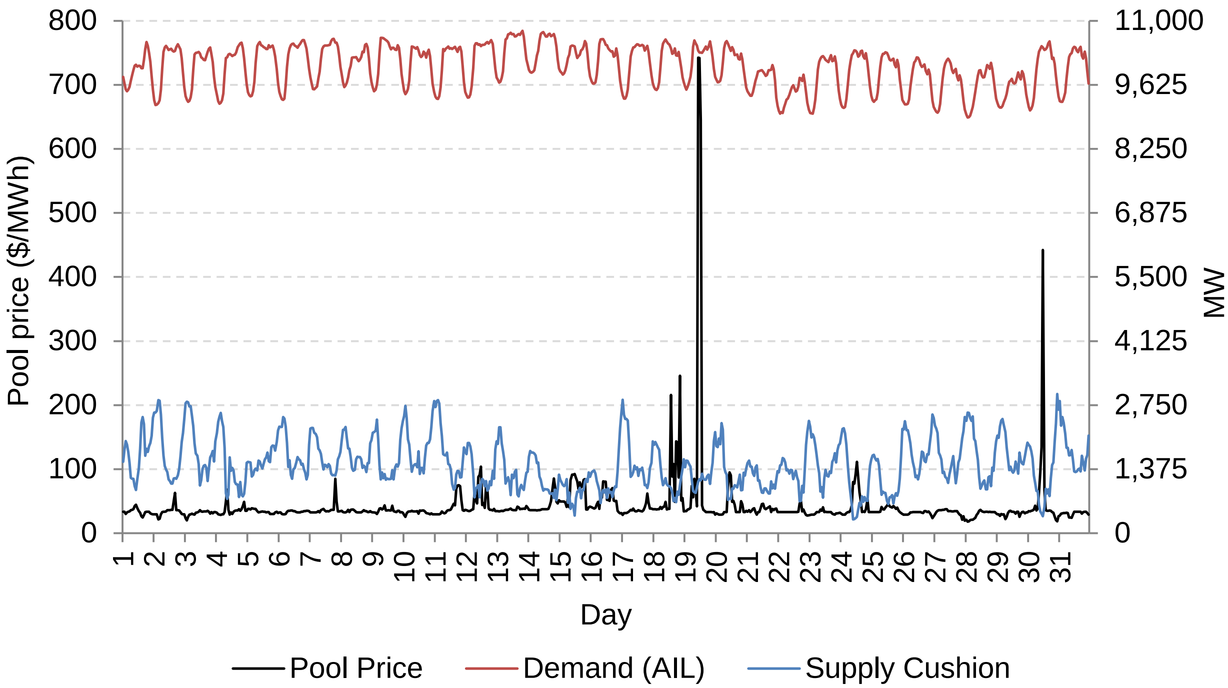
Figure 5: Utilization of ATC for imports on the BC/MATL intertie, January 2020



1.2.2 March 2020

The average pool price in March 2020 was $42.16/MWh. The hourly pool price, demand, and supply cushion for each hour in March is illustrated in Figure 6.

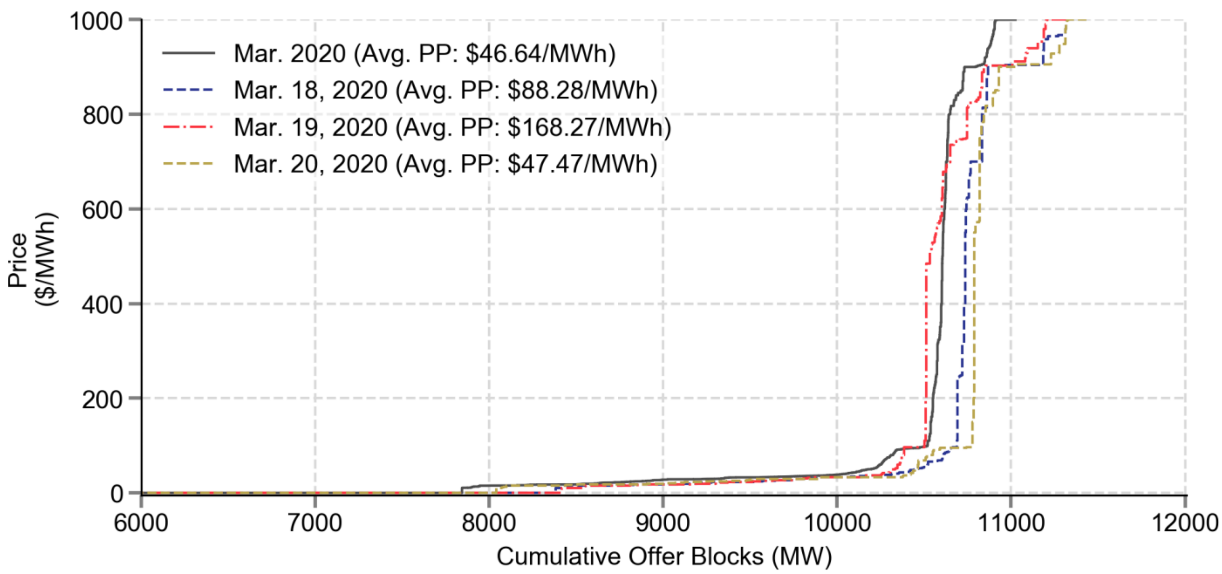
Figure 6: Hourly pool price, demand, and supply cushion, March 2020



In March, there were three days when the pool price exceeded $200/MWh in any hour of day. On March 18, the pool price was greater than $100/MWh from hour-ending 15 to 22. The highest pool price in the month was $744.85/MWh, which occurred on March 19 in hour-ending 12. Finally, on March 30 the pool price was $442.03/MWh in hour-ending 13.

Compared to the Cold Week, as illustrated in Figure 7, the on-peak average supply curve for March 19 indicates minimal changes in total generation supply compared to the day before and after. However, the shape of the average market supply curve indicates that more generation was offered at prices higher than short-run marginal cost compared to the day before and after.

Figure 7: On-peak average market supply curves, March 2020

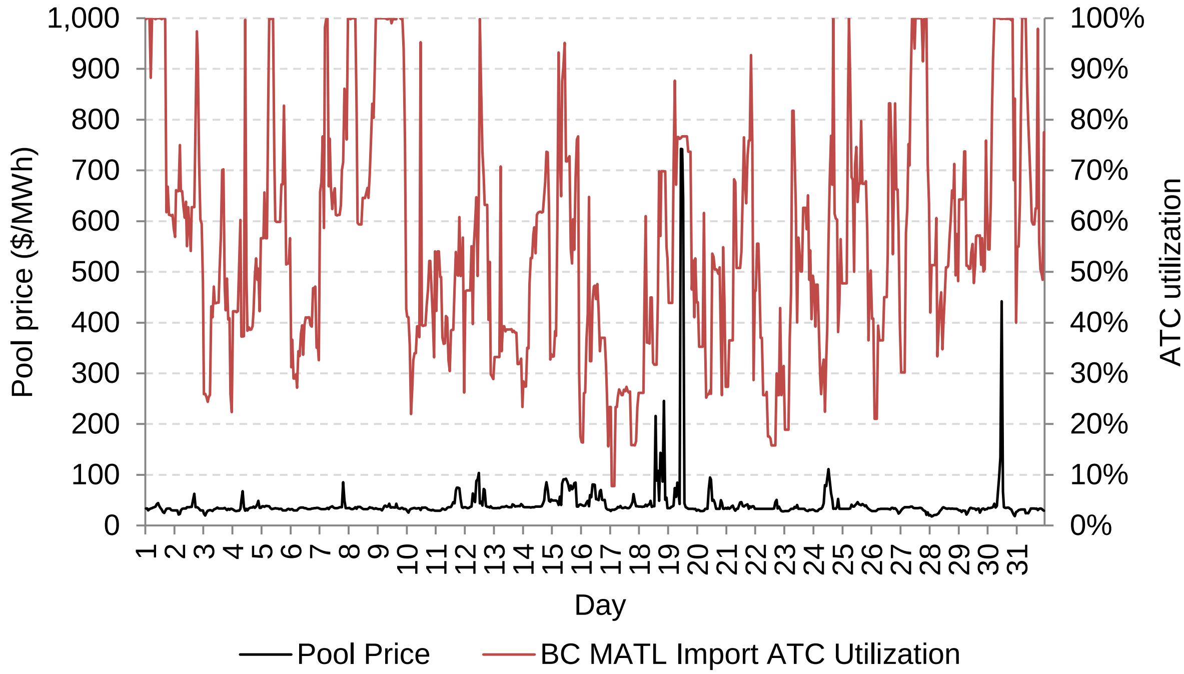


These prices were set in hours with relatively high supply cushions, which contrast to those in January when the supply cushion was much lower as a result of extremely high demand and limited supply. In other words, the high prices in March were not associated with unusually high levels of demand or highly limited generator availability, though production by wind generators did not exceed 250 MW in any of these hours.

In these hours (and others where the supply cushion is low), generators earned revenue in excess of short-run marginal cost. These revenues are sometimes referred to as net revenue. In an industry, such as electricity production, where short-run marginal costs are fairly constant and installing production capacity requires a significant amount of fixed cost to be incurred, periods where net revenues are earned by producers are expected and required.

As illustrated in Figure 8, consistent with pool prices being generally lower in March than in January, the ATC on the BC/MATL intertie was utilized relatively less in March than in January. Exports were scheduled in March but none of these hours coincided with high prices.

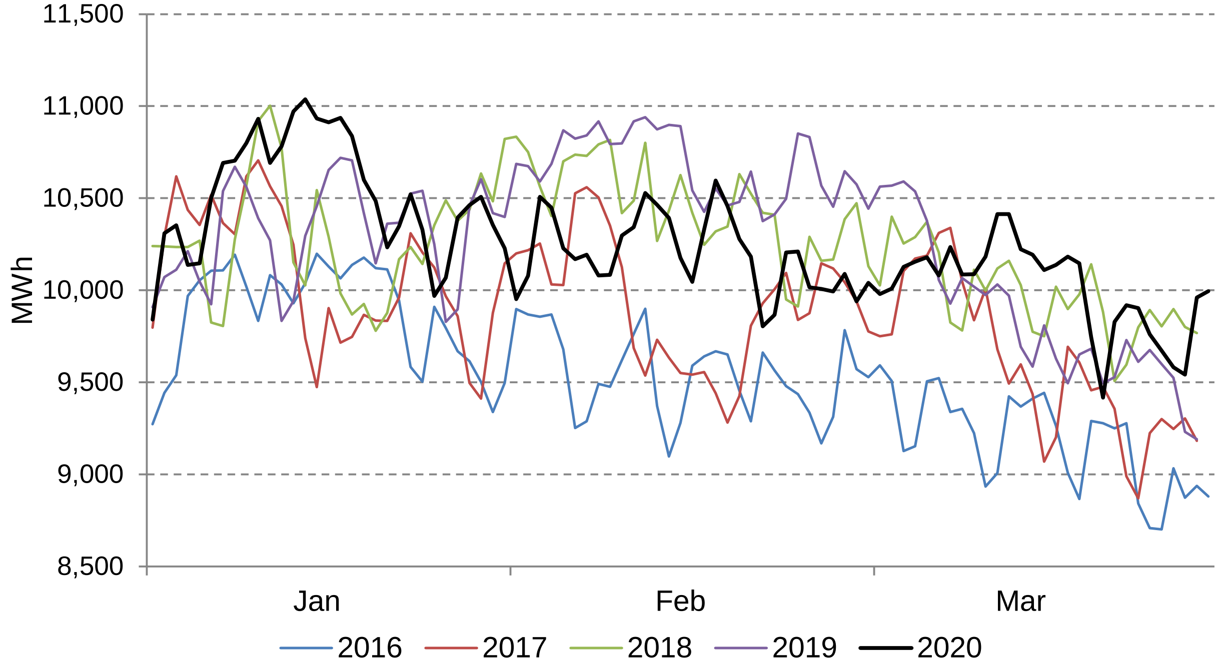
Figure 8: Utilization of ATC for imports on the BC/MATL intertie, March 2020



In mid-March, governments at all levels in Canada began restricting activities in an effort to slow the spread of COVID-19. Due to the decrease in economic activity and the implementation of social distancing guidelines, electricity demand is expected to decrease. Further, the decrease in world oil prices is expected to decrease electricity demand in Alberta.

Figure 9 illustrates the average hourly demand for electricity by day for the first quarter of the years 2016 to 2020. Demand for electricity exhibits consistent seasonality, generally declining through the first quarter as winter transitions to spring, and varies across years due to realised weather conditions. While some other electricity markets have reported significant declines in demand from mid-March 2020, this does not appear to be the case in Alberta (though it does appear in April). The MSA is also monitoring load shape to see whether there have been shifts in demand through the day, for example a slower morning ramp. Again, the impacts to the end of March do not appear large.

Figure 9: Average hourly demand for electricity, by day in Q1, 2016 to 2020



1.3 Interties

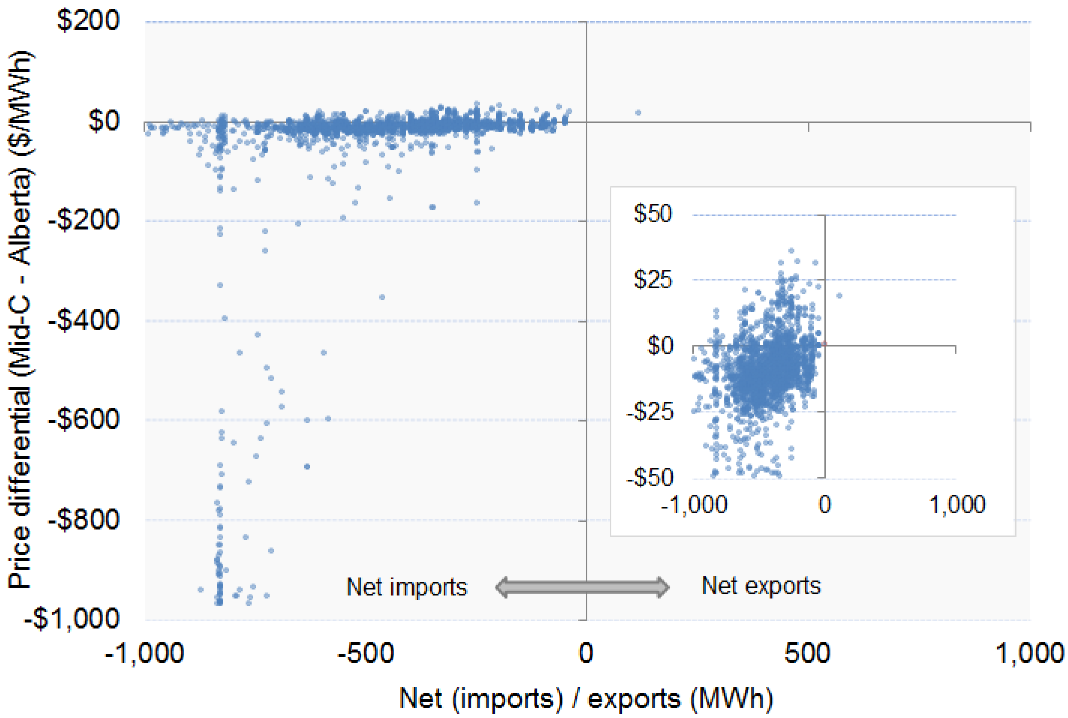
An efficient market is expected to result in electricity flowing from places where price (and cost) is low to where price (and cost) is high. When the relevant places are different electricity markets, this is expected to occur as a result of traders scheduling exports from low price markets and associated imports into high price markets.

1.3.1 BC/Montana intertie

Figure 10 compares the price differential between the Alberta and Mid-Columbia markets, which is defined as the price in the Mid-Columbia market less the pool price in Alberta, to net exports from Alberta across the BC/MATL intertie, which is negative when Alberta is a net importer on this intertie, for all hours in Q1 2020.

During the quarter, the price of electricity in the Mid-Columbia market was often much 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 10: Intertie price differentials and net flow on the BC/MATL intertie

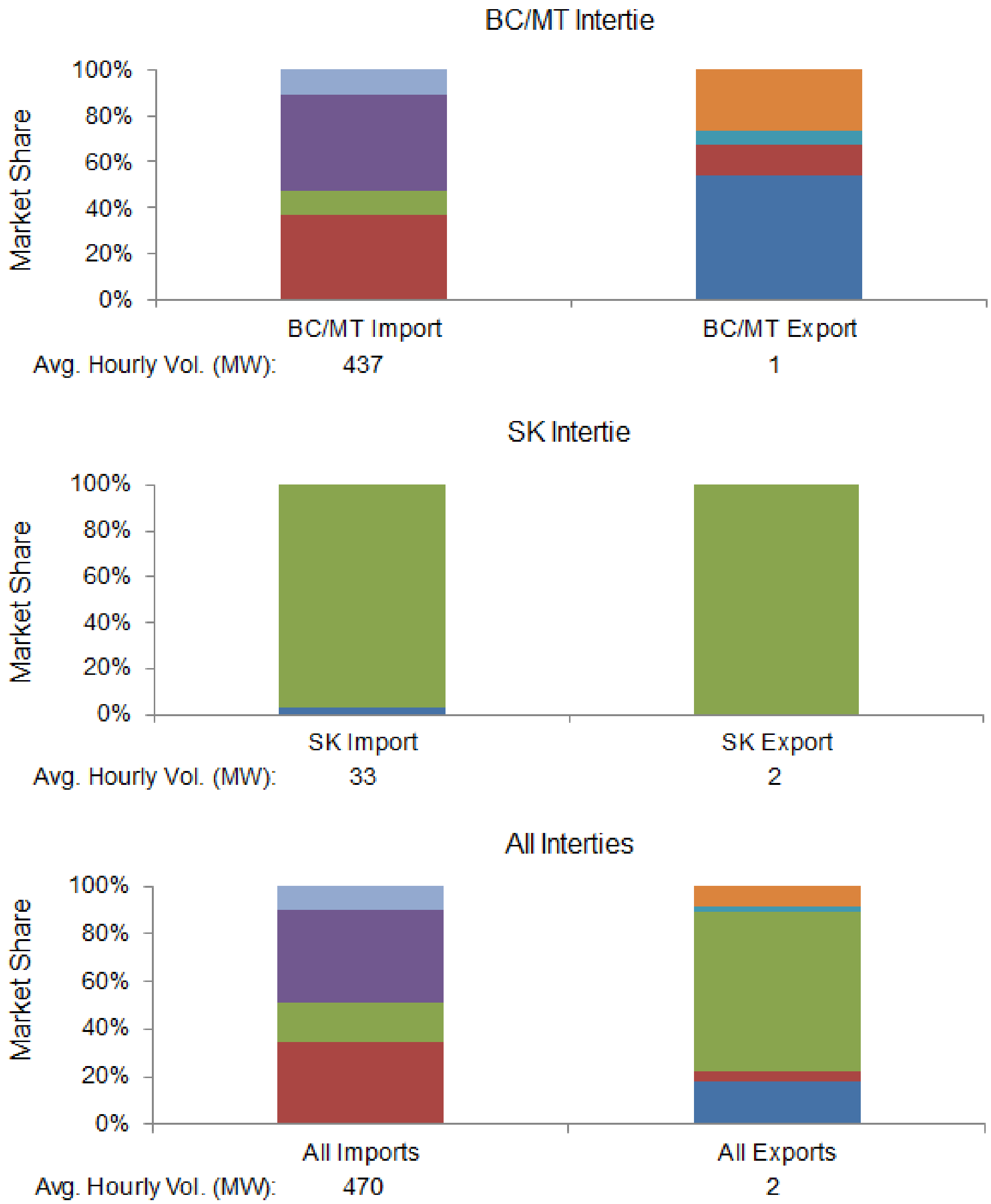


1.3.2 Participation on the Interties

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 Q1 2020 are illustrated in Figure 11.

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 11: Shares of imported and exported electricity, by intertie and market participant



2 THE MARKETS FOR OPERATING RESERVES

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 (which may be negative) 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 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 Q1 2020, as reported in Table 2, the total cost of operating reserves was 24% higher than the same quarter the previous year. The cost of active reserves in the period of extremely cold weather in January was a significant driver; costs outside this week were considerably lower. Standby procurement costs were lower compared to the previous year but activation rates, and consequently activation costs, were higher. While most of the cost of standby activations was incurred in January, activation rates remained high in all three months of the quarter.

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.

As reported above in Table 1, in Q1 2020 net imports to Alberta exceeded a total of 1 TWh (about 5% of Alberta Internal Load), compared to Alberta being a net exporter in the same quarter of the previous year. As a result, volume of standby contingency reserve activations was 61.8 GWh in the quarter, compared to 24.3 GWh in the same period last year.

Contingency reserve providers understand that the chance of activation is higher when the AESO elects to procure more contingency reserves than normal to cover the intertie and will thus increase the standby activation price they offer into the operating reserve market. This can be seen in the average cost of activating standby contingency reserves increasing by 37% for standby spinning reserves and 54% for standby supplemental reserves in this quarter compared to the year earlier.

Table 2: Operating Reserve Summary

Total Cost ($ Millions)	Jan-20	Feb-20	Mar-20	Q1 2020	Q1 2019	*% Change*
Active Procured	**52.2**	**5.2**	**8.5**	**65.8**	**56.6**	***16%***
RR	12.7	2.2	3.3	18.2	16.7	*9%*
SR	20.4	2.0	3.2	25.6	21.8	*17%*
SUP	19.1	1.0	1.9	22.0	18.1	*22%*
Standby Procured	**0.4**	**0.2**	**0.2**	**0.8**	**1.4**	***-42%***
RR	0.2	0.1	0.1	0.4	0.4	*-7%*
SR	0.2	0.1	0.1	0.4	0.7	*-49%*
SUP	0.0	0.0	0.0	0.0	0.3	*-84%*
Standby Activated	**6.3**	**0.9**	**0.9**	**8.1**	**2.3**	***258%***
RR	0.0	0.0	0.0	0.0	0.0	*-47%*
SR	4.7	0.7	0.6	6.0	1.6	*270%*
SUP	1.6	0.3	0.2	2.1	0.6	*243%*
Total	**58.9**	**6.3**	**9.6**	**74.8**	**60.3**	***24%***

Total Volume (GWh)	Jan-20	Feb-20	Mar-20	Q1 2020	Q1 2019	*% Change*
Active Procured	**540.8**	**488.7**	**517.0**	**1,546.5**	**1,408.1**	**10%**
RR	124.2	112.0	119.6	355.7	351.6	*1%*
SR	208.5	188.4	199.0	595.9	528.1	*13%*
SUP	208.2	188.3	198.5	594.9	528.5	*13%*
Standby Procured	**166.2**	**157.3**	**165.9**	**489.5**	**509.5**	***-4%***
RR	59.4	55.6	59.4	174.4	172.5	*1%*
SR	79.3	75.3	79.2	233.8	243.1	*-4%*
SUP	27.5	26.5	27.3	81.3	93.9	*-13%*
Standby Activated	**25.5**	**19.7**	**17.0**	**62.1**	**24.8**	***150%***
RR	0.1	0.1	0.1	0.3	0.5	*-40%*
SR	17.6	13.7	12.2	43.5	16.1	*171%*
SUP	7.7	5.8	4.7	18.3	8.2	*123%*
Total	**732.5**	**665.7**	**699.9**	**2,098.1**	**1,942.5**	***8%***

Average Cost ($/MWh)	Jan-20	Feb-20	Mar-20	Q1 2020	Q1 2019	*% Change*
Active Procured	**96.49**	**10.58**	**16.36**	**42.56**	**40.19**	**6%**
RR	102.17	19.43	27.78	51.12	47.52	8%
SR	97.97	10.42	16.18	42.98	41.32	4%
SUP	91.61	5.49	9.67	37.02	34.18	8%
Standby Procured	**2.42**	**1.12**	**1.45**	**1.68**	**2.77**	**-40%**
RR	3.99	1.31	1.81	2.39	2.60	-8%
SR	1.90	1.25	1.49	1.55	2.93	-47%
SUP	0.54	0.34	0.57	0.49	2.69	-82%
Standby Activated	**248.13**	**47.81**	**50.60**	**130.78**	**91.50**	**43%**
RR	63.97	57.06	51.26	58.22	65.09	-11%
SR	266.67	49.66	51.60	138.15	101.14	37%
SUP	208.73	43.26	48.00	114.49	74.38	54%
Total	**80.42**	**9.45**	**13.66**	**35.63**	**31.03**	***-13%***

2.2 Liquidity

Unlike in the energy market, where the *Fair, Efficient and Open Competition Regulation* and the ISO rules, require that all available energy be offered to the market, participation in operating reserves markets is voluntary. Participation is limited by technical requirements that vary based on the product. However, the potential supply of reserves is significantly higher than the amount typically procured by the AESO. The MSA has undertaken an assessment of long-term trends related to participation in these markets, with a focus on liquidity in the markets for active on-peak regulating, spinning, and supplemental reserves.

The average hourly volume of offers in the markets for active on-peak regulating, spinning, and supplemental reserves are illustrated in Figures 12 to 14 on a monthly basis for the period from 2012 to the end of Q1 2020.

In the active on-peak active regulating reserve market the quantity of offers has trended slightly downward in recent years. Similar trends are not apparent in the on-peak active spinning and supplemental reserves markets, although current offer volumes remain below those observed in 2013.

Figure 12: Offer volume by fuel type for on-peak regulating reserves

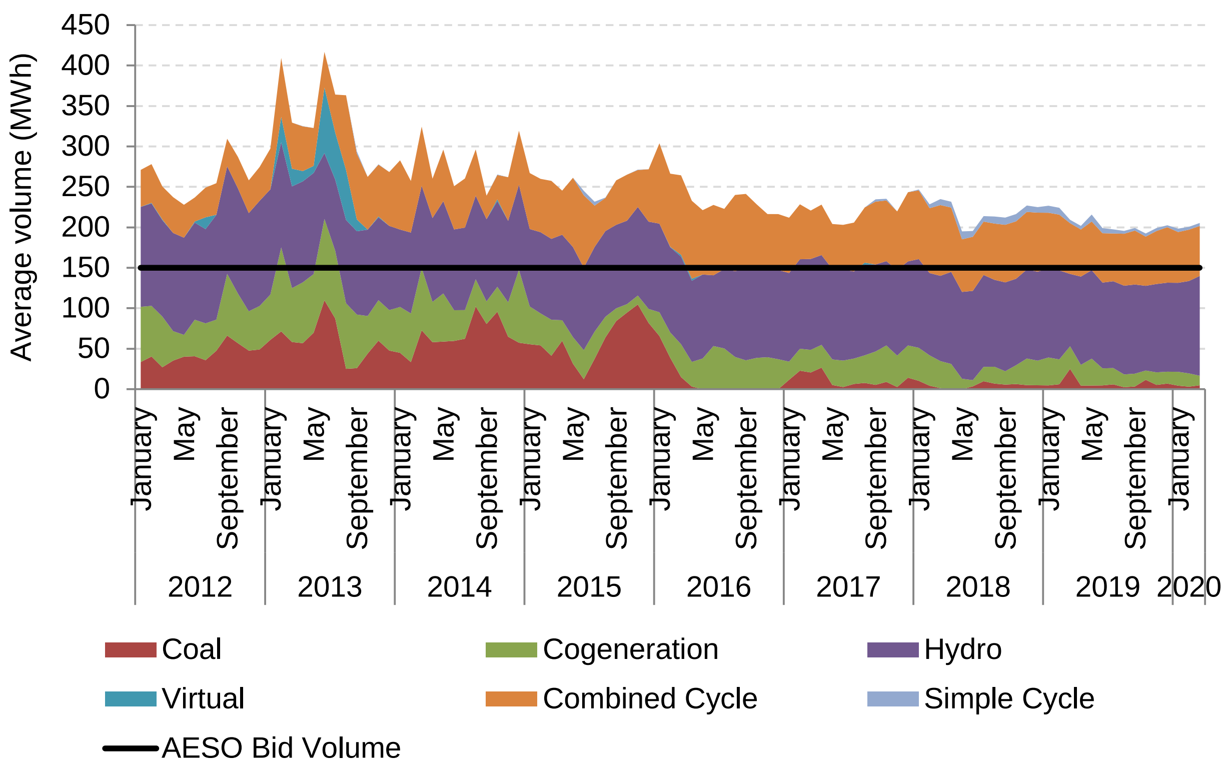


Figure 13: Offer volume by fuel type for on-peak spinning reserve

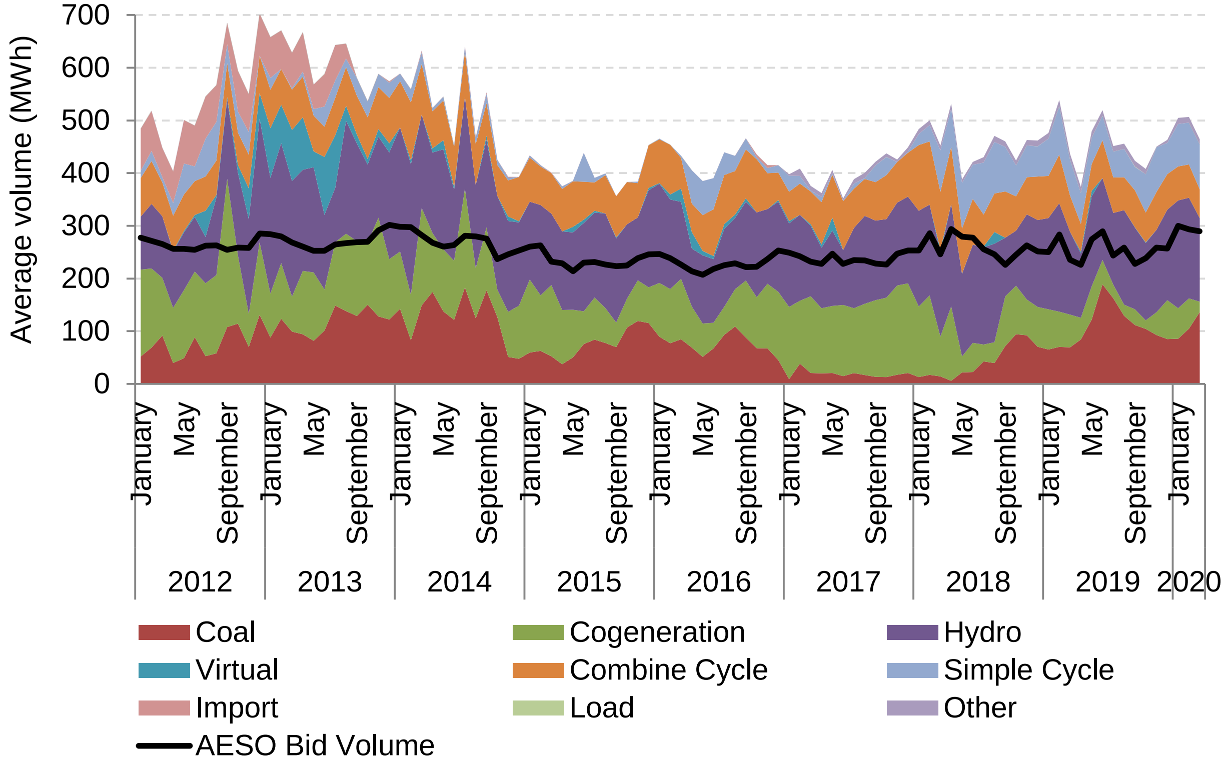
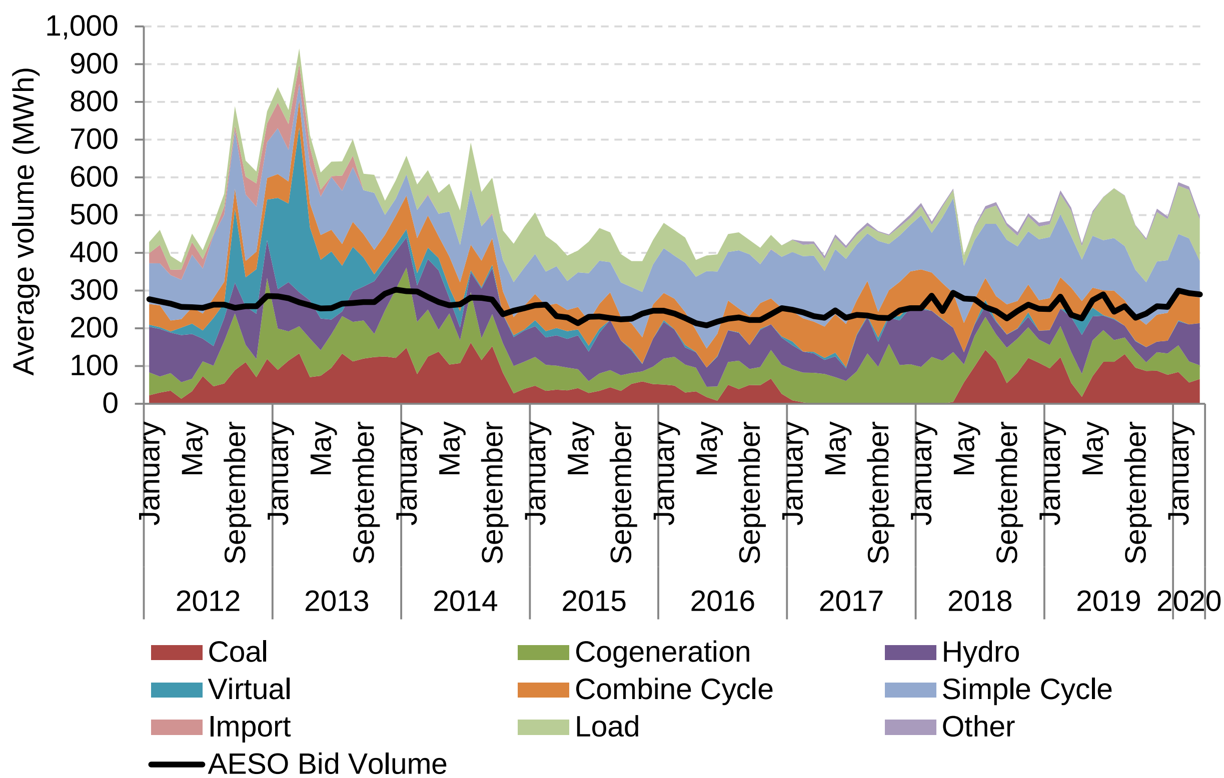


Figure 14: Offer volume by fuel type for on-peak supplemental reserve



In all these markets, the variation in fuel types offering into the market has decreased since 2013. While imports are eligible to provide spinning and supplemental reserves products, import market participants have not offered into these markets since 2013. Offers associated with coal-fired generators decreased significantly in each of these markets between late 2016 and early 2018. Since early 2018, such offers have reappeared in the spinning and supplemental reserve markets but not in the regulating reserve market. There was an increase in offers from simple cycle generators beginning in 2018 in all three markets. In the supplemental reserve market, participation by load participants increased in 2019.

3 THE FORWARD MARKET

The volume of trades for most standard shape forward market contracts has dropped significantly since Q4 2018. 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 in Table 3.

Table 3: Forward market trade volumes, standard products only (TWh)

		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	4.23	1.28	1.75	0.63	7.91
	Year	**0.33**	**19.51**	**6.25**	**12.69**	**2.27**	**41.06**
2020	**Q1**	0.05	3.54	0.96	1.38	0.26	6.20

Recent changes to one of the main Energy Price Setting Plans (EPSP) used to set retail prices for the electricity customers on the Regulated Rate Option have resulted in a partial shift away from the procurement of standard monthly products to full-load contracts. A standard monthly contract is settled based on an equally-weighted average of pool prices during the delivery hours specified by the contract. Alternatively, a full-load contract results in the seller taking on a (financial) obligation to provide a percentage of the RRO load in each hour of the contract. This shift in procurement may have reduced the traded volumes of standard monthly products, although it will have shifted liquidity to non-standard products.

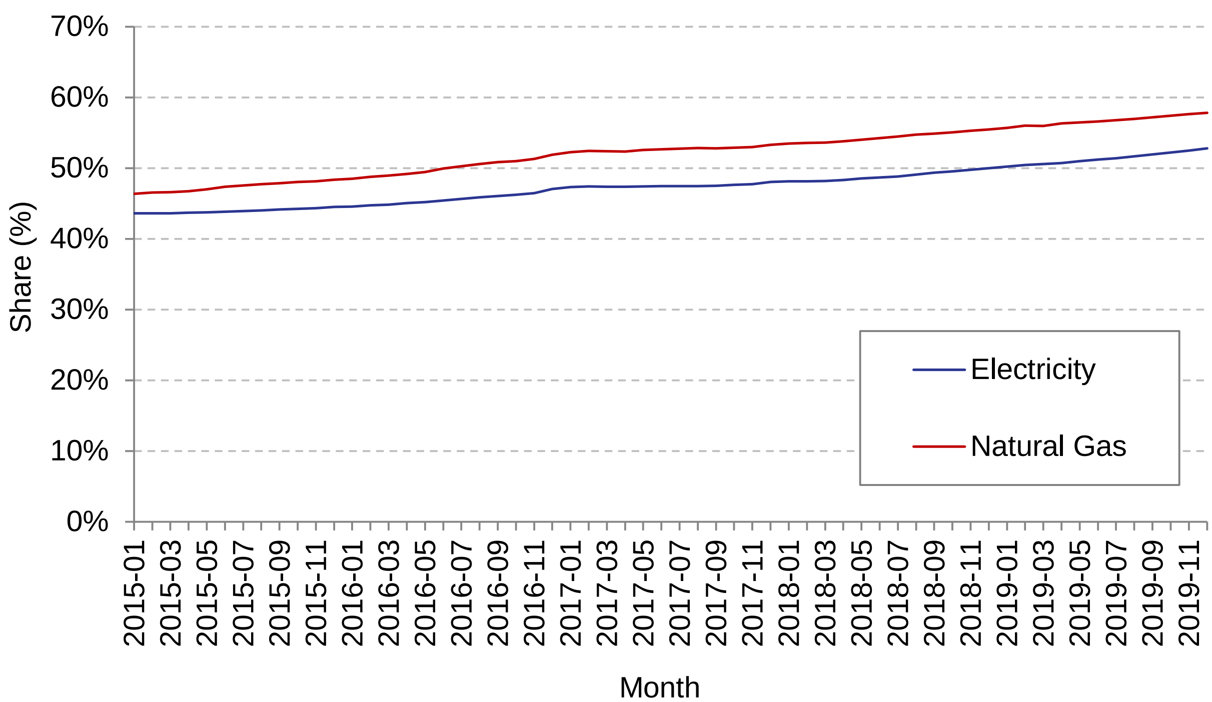
4 THE RETAIL MARKET

4.1 Competitive market shares

The share of residential customers on competitive contracts has increased at a steady but relatively slow rate for many years. As illustrated in Figure 15, competitive residential electricity and natural gas contract shares tend to trend together because of the popularity of dual-fuel contracts among residential customers.

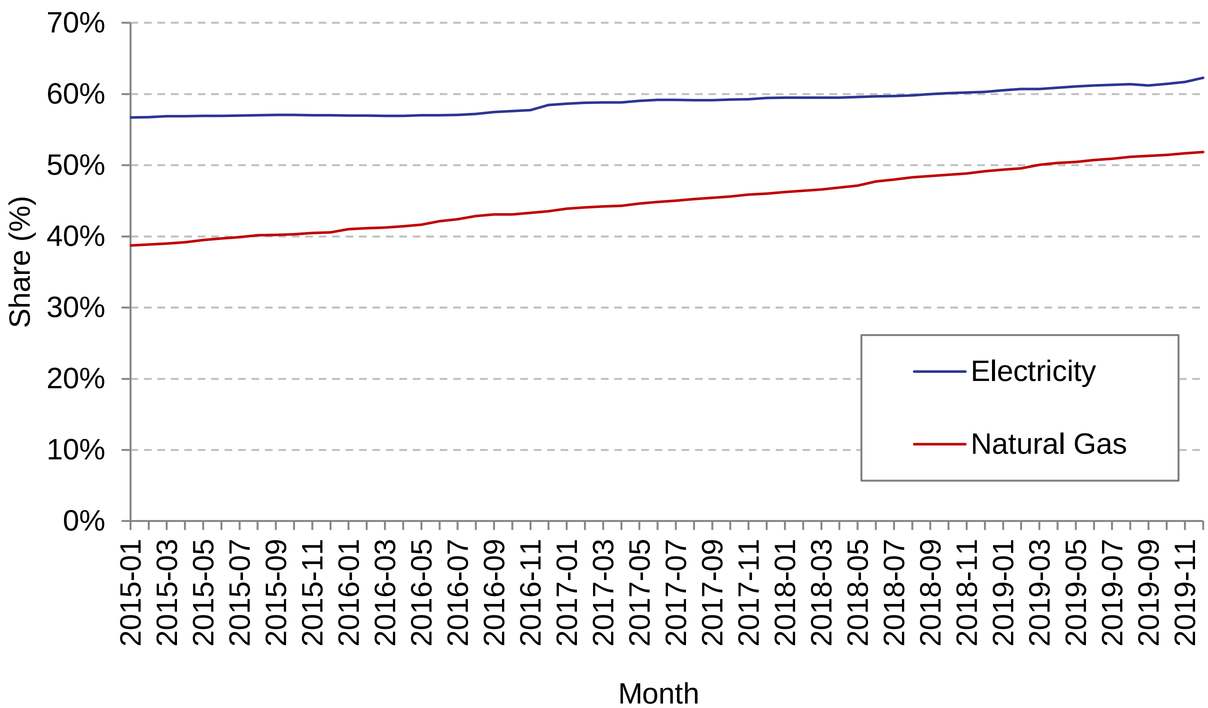
A cap on RRO rates came into effect in 2017 and continued until late 2019. There appears to have been little change in the steady but relatively slow rate of switching towards competitive contracts as a result of the rate cap.

Figure 15: Share of residential customers on competitive retail contracts, January 2015 to December 2019



For commercial customers, as illustrated in Figure 16, the share of customers on competitive contracts is higher compared to residential customers for electricity but not natural gas. Similar to residential customers, the share of commercial customers on competitive contracts continued to increase but at a slow rate.

Figure 16: Share of commercial customers on competitive retail contracts, January 2015 to December 2019

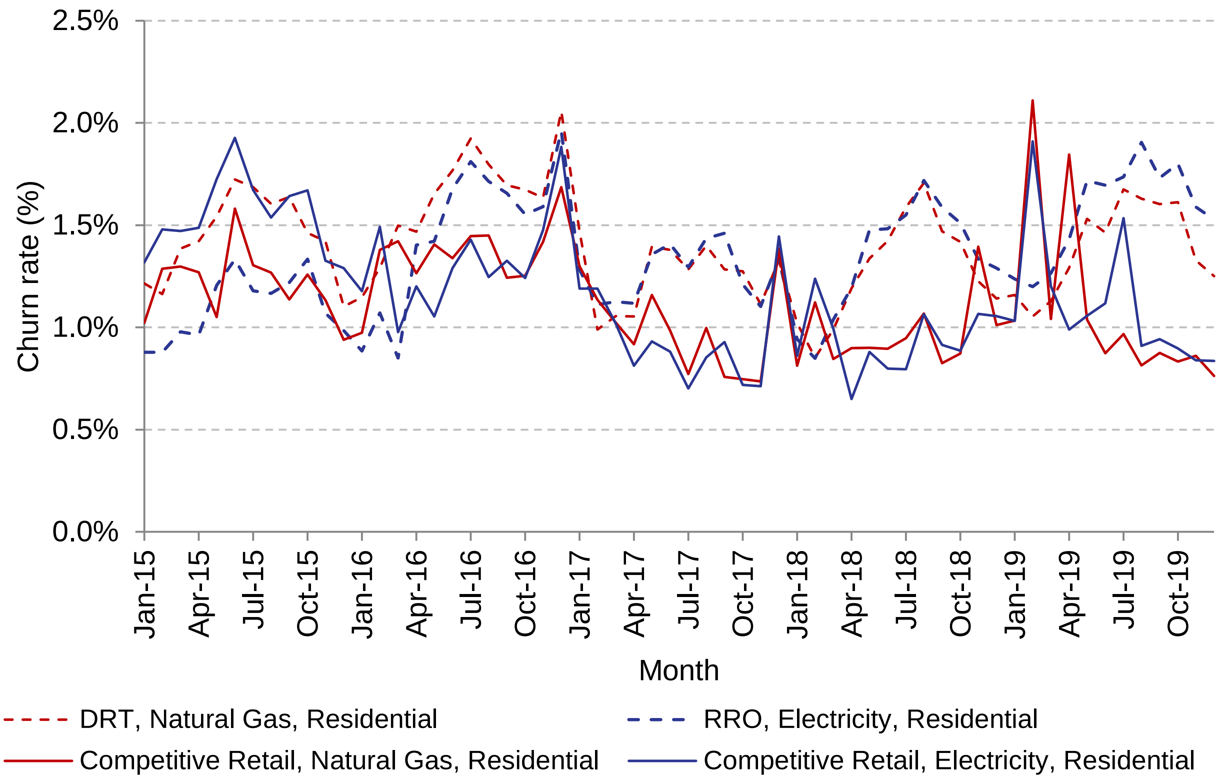


4.2 Churn

Even a static share of customers on competitive contracts may be consistent with vigorous competition between competitive retailers since it does not record how frequently customers move between retailers seeking better deals. High churn rates indicate that customers switch retailers frequently, which can be a sign of a healthy competitive retail market in which retailers compete for customers.

Monthly churn rates for residential customers have generally ranged from 1 to 2% per month over the past five years are illustrated in Figure 17. Churn rates for regulated energy products—the RRO for electricity and the Default Rate Tariff (DRT) for natural gas—have typically exceeded churn rates among competitive retailers, in line with the increase in residential customers switching to competitive retail products. Despite the presence of the RRO rate cap between 2017 and 2019, capped RRO rates were often higher than rates offered by competitive retailers, possibly motivating the difference in churn rates over this period.

Figure 17: Retail churn rates, residential customers, January 2015 to December 2019



4.3 Regulated retail market

Albertans who are unable to sign with or elect not to 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.

4.3.1 Regulated Rate Option (RRO)

The RRO "billing rate" averaged 7.72 ¢/kWh in the four largest distribution service areas in Q1 2020. While billing rates paid by customers have increased slightly since the end of the RRO rate cap at the end of November 2019 as illustrated in Figure 18, recent billing rates are in line with historical RRO monthly rates[5] (uncapped rates) in many months where the rate cap was in effect as illustrated in Figure 19.

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[5] "Monthly rates" refers to RRO rates determined in accordance with RRO providers' energy price setting plans, without accounting for the effect of the 6.8 ¢/kWh rate cap. "Billing rates" are the RRO rates paid by customers, accounting for the rate cap. With the end of the rate cap, customers are now billed monthly rates.

Figure 18: Capped residential RRO rates, January 2015 to March 2020

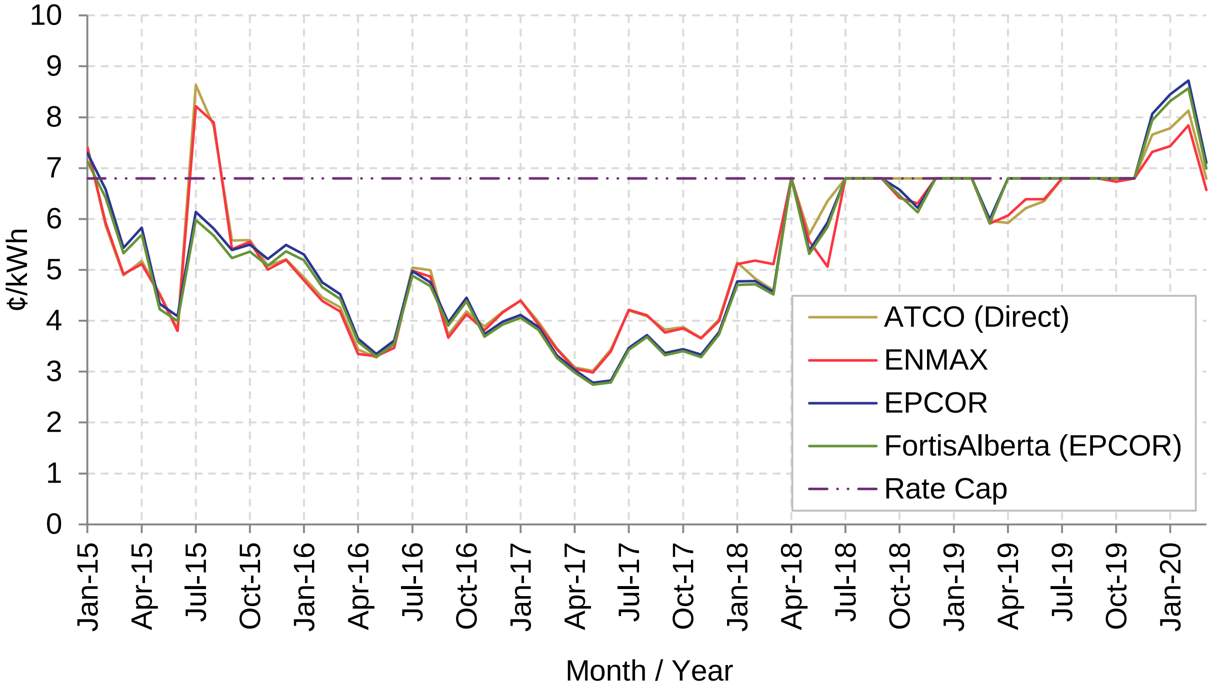
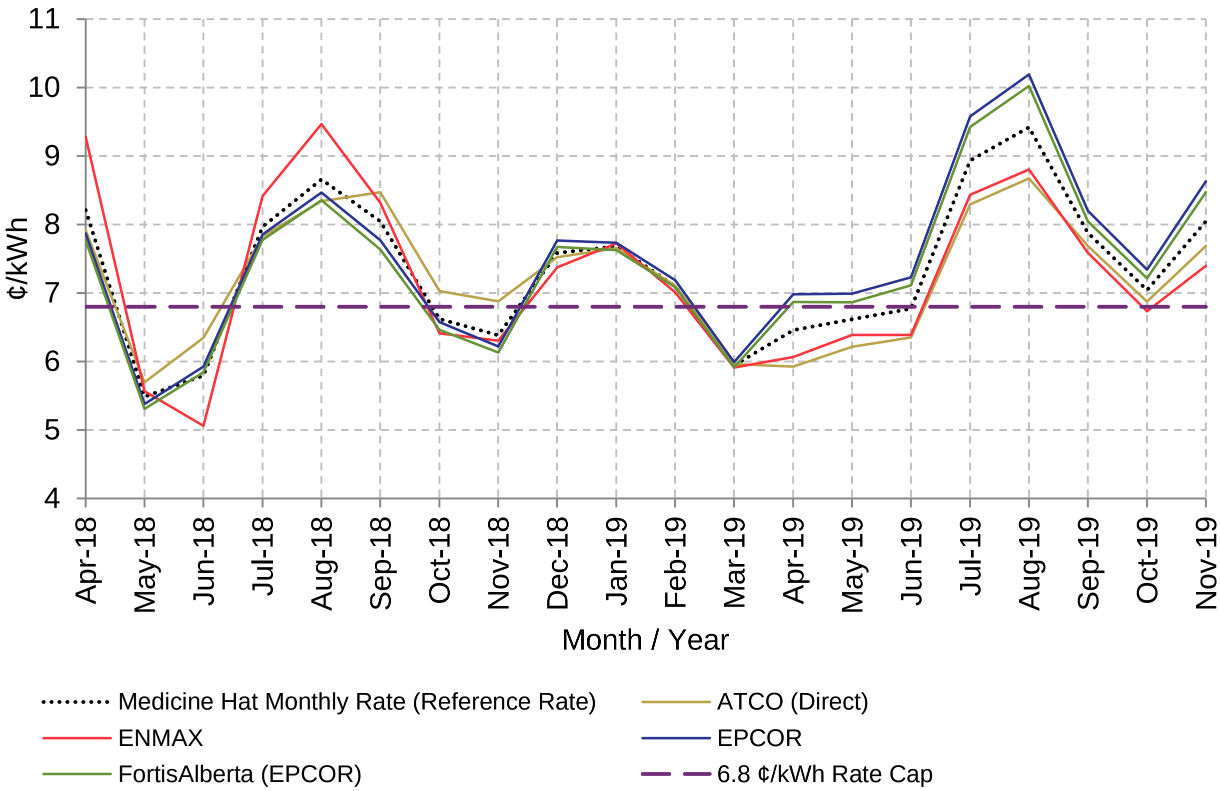


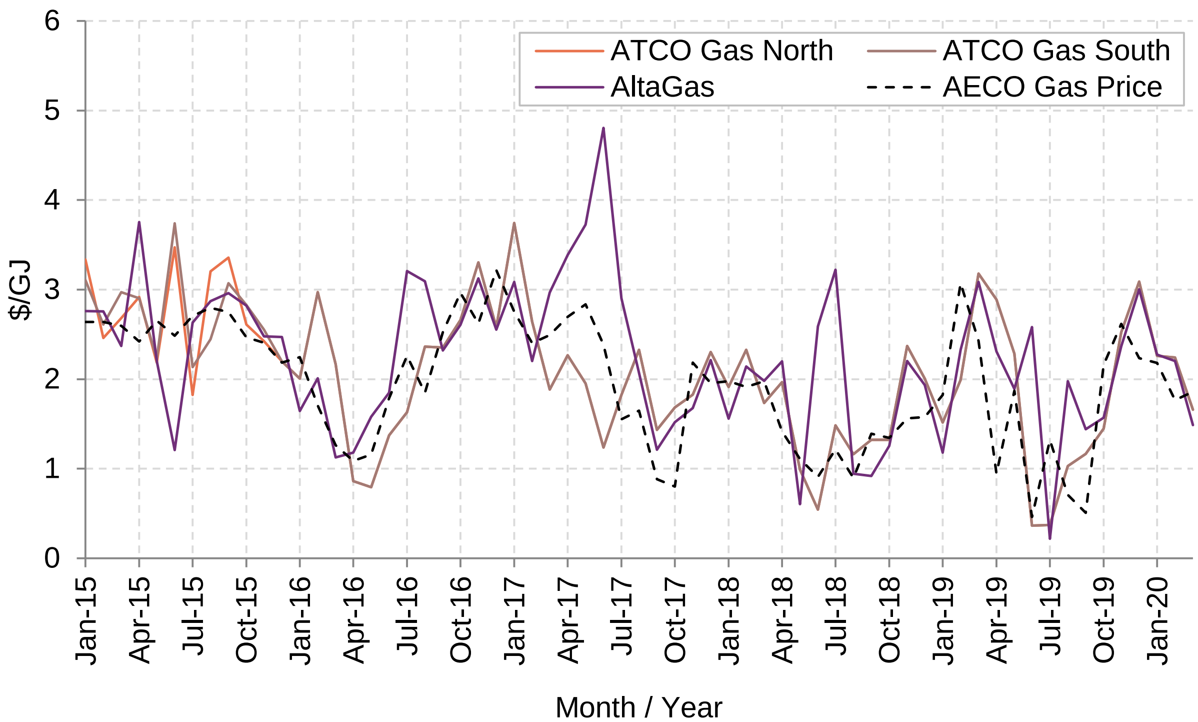
Figure 19: Uncapped residential RRO rates, April 2018 to November 2019



4.3.2 *Default Rate Tariff (DRT)*

As illustrated in Figure 20, DRT rates fell in Q1 2020, averaging $2.03/GJ across the quarter. DRT rates fell to historic lows in summer 2019 as a result of low wholesale natural gas prices. Both subsequently increased throughout the latter half of 2019 before falling again in Q1 2020.

Figure 20: DRT Rates, January 2015 - March 2020



5 ISSUE ASSESSMENTS AND INVESTIGATIONS

5.1 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 committing 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.

5.2 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 *Fair, Efficient and Open Competition Regulation*.

In this case, there was no impact on the wholesale electricity market resulting from the sharing of the information and the incident is not a part of a recurring problem. Given the circumstances in this case the MSA declined to investigate. Notwithstanding the decision to take no action the MSA would note that the communication protocols could be improved between the parties involved in this incident. Further, market participants should have procedures in place to prevent the disclosure of and/or trading on non-public outage information.

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 March 31, 2020, as reported in Table 4, the MSA addressed 77 ISO rules compliance matters.[6] An additional 82 matters were carried forward to the next quarter. During this time frame, 27 matters were addressed with notices of specified penalty, totaling $46,750 in financial penalties, with details provided in Table 5.

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

Table 4: ISO rules compliance determinations made by the MSA

Section of the ISO Rules	**Forbearance**	**Notice of Specified Penalty**	**No Breach**
201.7	1	1	-
203.3	8	8	2
203.4	13	4	2
203.6	3	1	-
205.3	1	4	-
205.4	13	-	-
205.5	1	5	-
205.6	1	2	-
303.1	1	-	-
304.9	2	-	-
306.4	-	1	-
306.5	-	1	-
306.7	-	-	1
505.4	1	-	-
Total	45	27	5

The sections of the ISO rules listed in Tables 4 and 5 fall into the following categories:

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

Table 5: Specified penalties issued between January 1, 2020 and March 31, 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**
	201.7	**203.3**	**203.4**	**203.6**	**205.3**	**205.5**	**205.6**	**306.4**	**306.5**		
Alberta Newsprint Company		1,250	5,000							6,250	2
Alberta Pacific Forest Industries Inc.			1,250							1,250	1
AltaGas Ltd.		1,500								1,500	1
Balancing Pool					500					500	1
Canadian Natural Resources Ltd.		1,500	1,500							3,000	2
Dow Chemical Canada ULC			750							750	1
ENMAX Power Corporation								250		250	1
Heartland Generation Ltd.						250				250	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.		10,000							500	10,500	2
NorthPoint Energy Solutions Inc.				750						750	1
Northstone Power Corp.							750			750	1
TransAlta Corporation		1,500								1,500	2
TransAlta Generation Partnership		1,500			2,500	12,000	500			16,500	9
Total	500	19,750	8,500	750	3,000	12,250	1,250	250	500	46,750	27

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 March 31, 2020, as reported in Table 6, the MSA addressed 12 ARS O&P compliance matters. An additional 71 matters were carried forward to the next quarter. During this time frame, three matters were addressed with notices of specified penalty, totaling $6,250 in financial penalties, with details provided in Table 7.

Table 6: O&P ARS compliance determinations made by the MSA

Reliability standard	Forbearance	Notice of Specified Penalty	No breach
BAL-005	2	-	-
COM-001	-	-	1
COM-002	-	-	2
INT-009	2	-	-
PRC-001	1	1	-
PRC-018	-	1	-
VAR-002	1	1	-
Total	6	3	3

Table 7: Specified penalties closed between January 1, 2020 and March 31, 2020 for contraventions of O&P ARS

Market participant	**Total specified penalty by ARS ($)**			**Total ($)**	**Matters addressed with a penalty**
	PRC-001	**PRC-018**	**VAR-002**		
Alberta Newsprint Company			2,250	2,250	1
EPCOR Distribution & Transmission Inc.		250		250	1
Fort Hills Energy Corporation	3,750			3,750	1
Total	3,750	250	2,250	6,250	3

The sections of 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