MARKET SURVEILLANCE ADMINISTRATOR

Q2/17 Quarterly Report

April – June 2017

August 11, 2017

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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Wholesale Market

Summary

Pool price in Q2 2017 averaged $19.29/MWh ($14.98/MWh ext. off peak, $21.45/MWh ext. on peak), 29% higher than the same quarter last year. Despite this, the quarterly pool price was still 67% below the average price over the previous ten years (Figure 1).

Demand increased significantly year-over-year (+7%), in part due to the load decrease in Q2 2016 due to the Fort McMurray wildfire (Figure 2).

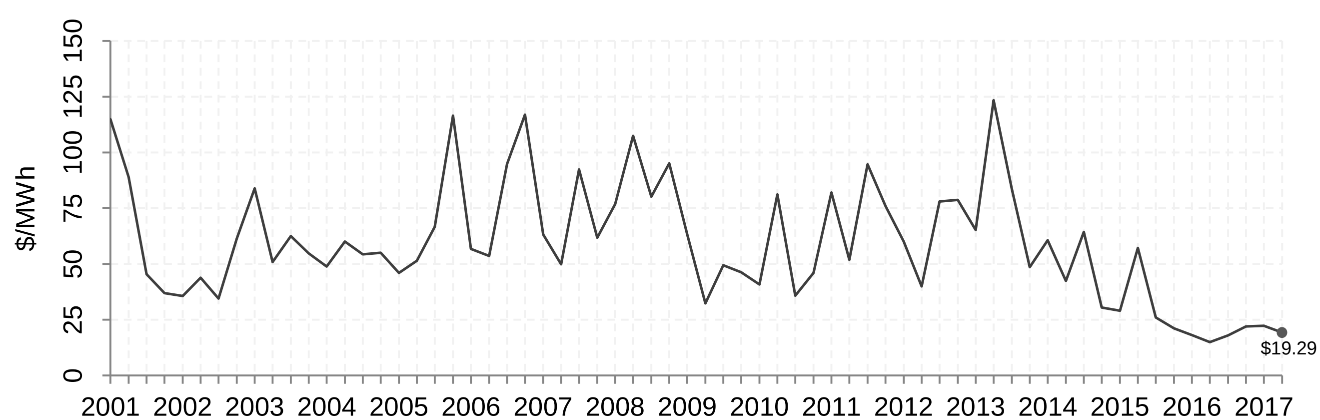
Similar to the same quarter of the previous year, there were few instances of physical scarcity. Figure 3 shows that supply cushion remained above 1,000 MW in most hours (when adjusted for export reductions and import availability).

Offer prices from coal-fired supply increased slightly relative to those in Q1 2017, with most of the supply offered at around $20/MWh (Figure 4). These offer prices are likely in the region of generators' short-run marginal cost. Coal-fired generation set the system marginal price (SMP) 72% of the time in this quarter (down from 83% in Q2 2016), while PPA coal-fired units set the SMP 65% of the time (down from 79% in Q2 2016).

Table 1: Q2/17 Summary Data

		2016	2017	*Change*
Avg Pool Price ($/MWh)	April	13.63	19.10	*+40%*
	May	15.89	21.90	*+38%*
	June	15.44	16.78	*+9%*
	Q2	**15.00**	**19.29**	***+29%***
Total Demand (AIL, GWh)	April	6,102	6,378	*+5%*
	May	5,844	6,507	*+11%*
	June	6,026	6,388	*+6%*
	Q2	**17,972**	**19,273**	***+7%***
Avg Supply Cushion (MW)	April	2,478	2,563	*+3%*
	May	1,966	2,008	*+2%*
	June	2,585	2,759	*+7%*
	Q2	**2,339**	**2,439**	***+4%***
Total Wind Generation (GWh)	April	344	360	*+5%*
	May	301	352	*+17%*
	June	377	370	*-2%*
	Q2	**1,022**	**1,082**	***+6%***
Avg Natural Gas Price (AECO-C, $/GJ)	April	1.09	2.69	*+148%*
	May	1.16	2.83	*+145%*
	June	1.79	2.38	*+33%*
	Q2	**1.34**	**2.64**	***+97%***
Net Imports (GWh)	April	45.7	260.1	*+469%*
	May	72.6	305.4	*+321%*
	June	-21.6	271.0	*-1355%*
	Q2	**96.7**	**836.5**	***+765%***

Figure 1: Average Quarterly Pool Price



The quarter was marked by a dramatic increase in imports, primarily due to large amounts of hydro generation in the Pacific Northwest resulting from a large snowpack this year. The impact of these imports is examined later in this report.

Available capacity utilization by fuel type was similar to seasonal levels in 2016 (Figure 5), with the exception of hydroelectric resources, whose generation increased markedly year over year.

Figure 6 shows how cogeneration generation fell in Q2 2017 when compared to the start of the year. Cogeneration volumes typically fall during the second quarter of the year, due to a combination of factors including heat de-rates, seasonal load reductions, and changes in offer behaviour. Generation can also be affected by extraneous events such as the Fort McMurray wildfire in 2016; much of Alberta's cogeneration is located in northeastern Alberta, and as such was disproportionately affected by the wildfire. Despite a lack of wildfire, Q2 2017 saw cogeneration availability and volumes both decrease when compared against previous months, in part due to unit de-rates due to high ambient temperatures in the quarter. High import levels and low demand relative to Q1 also contributed to these reductions. Figure 7 illustrates cogeneration offer behaviour in the second quarter of the year. Offers were particularly similar in the second quarters of 2015 and 2017, while 2016 offers were significantly influenced by the wildfire. Q1 2017 offers have been included for added context.

Zero-Dollar Hours

Pool prices settled at $0/MWh in 41 hours (1.9% of the time) in Q2 2017, with another 21 hours settling at $0.01/MWh. The zero dollar hours occurred between hours ending (HE) 1 to 9, with multiple zero dollar hours typically occurring within the same day. Furthermore, SMPs were $0/MWh for almost 47 hours (combined). A total of 80 hours in the second quarter settled at pool prices of $5/MWh or less.

The frequency of zero dollar hours was driven in part by high import levels during morning off-peak hours. Typically, Alberta imports more power during on-peak hours and less in the off-peak (or is a net exporter off-peak). However, in Q2 2017 Alberta was a net importer in most hours (see Figure 9 in the Imports section), particularly during off-peak hours where the zero dollar hours occurred.

In addition to the high levels of imports, zero dollar pool prices occurred in periods of low demand and/or high levels of wind generation.

The zero dollar hours had a small impact on the overall quarterly average pool price. The quarterly average pool price excluding any zero dollar hours was $19.66/MWh, or thirty-seven cents higher.

During the 41 zero dollar hours in the quarter, 2.3 GWh of LSSi was armed at a cost of $118,000 to enable 1.4 GWh of imports while 8.2 GWh of contingency reserves were used at a cost of $113,000 to enable imports. Import enablement procedures are described in greater detail below.

Figure 2: Growth in Total Alberta Internal Load (AIL, % Year-over-Year)

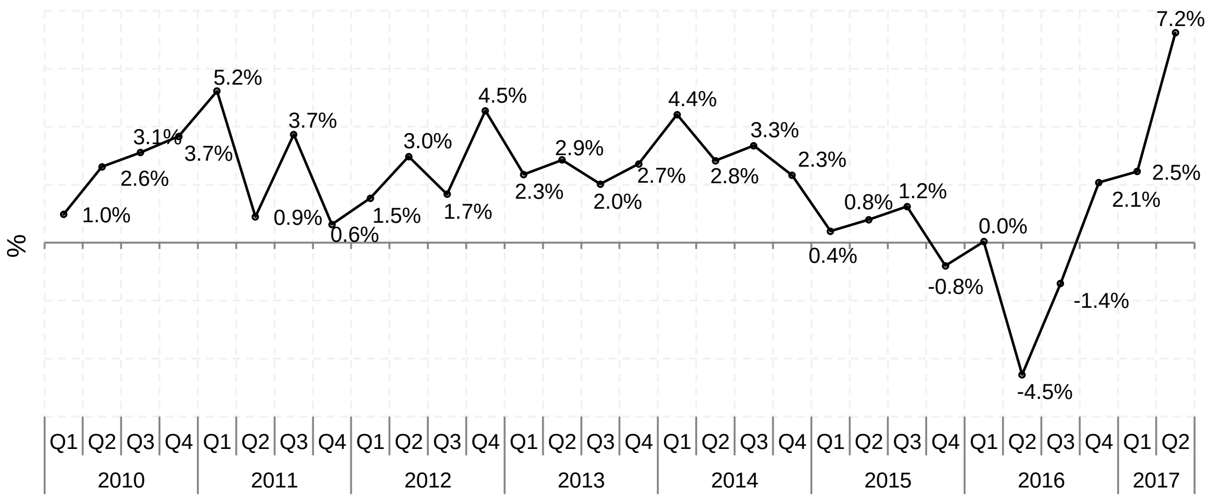
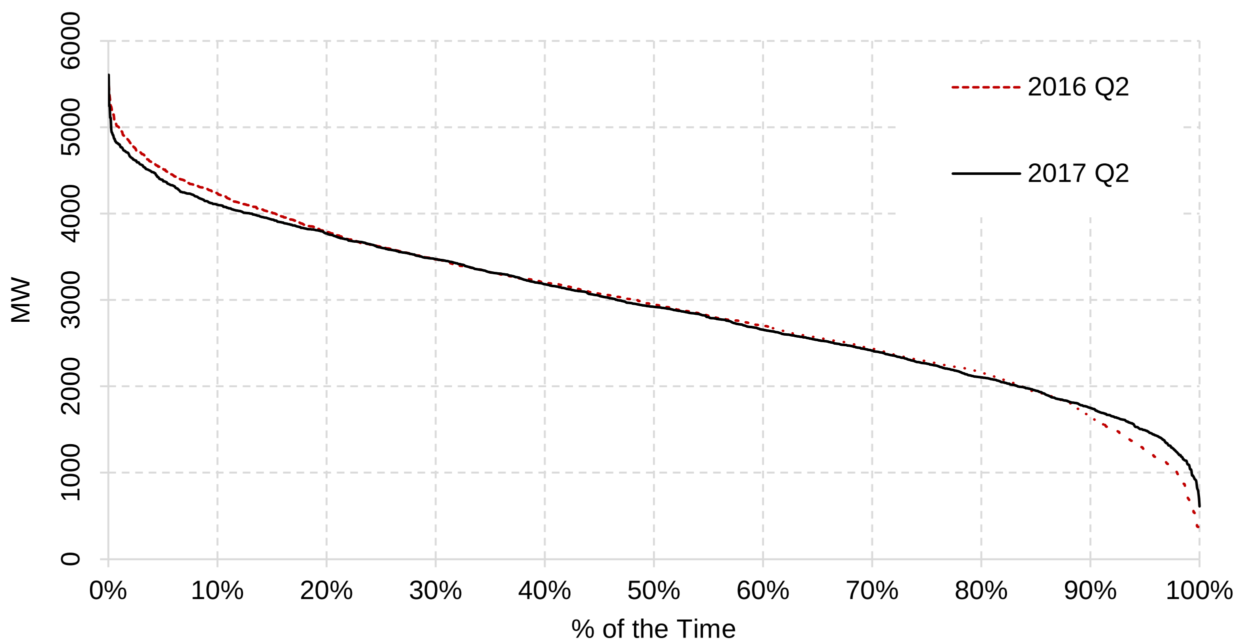


Figure 3: Adjusted[1] Supply Cushion Duration Curves



[1] Includes availability of additional imports or reduced exports in the supply cushion.

Figure 4: Aggregate Merit Order, Q2 2017

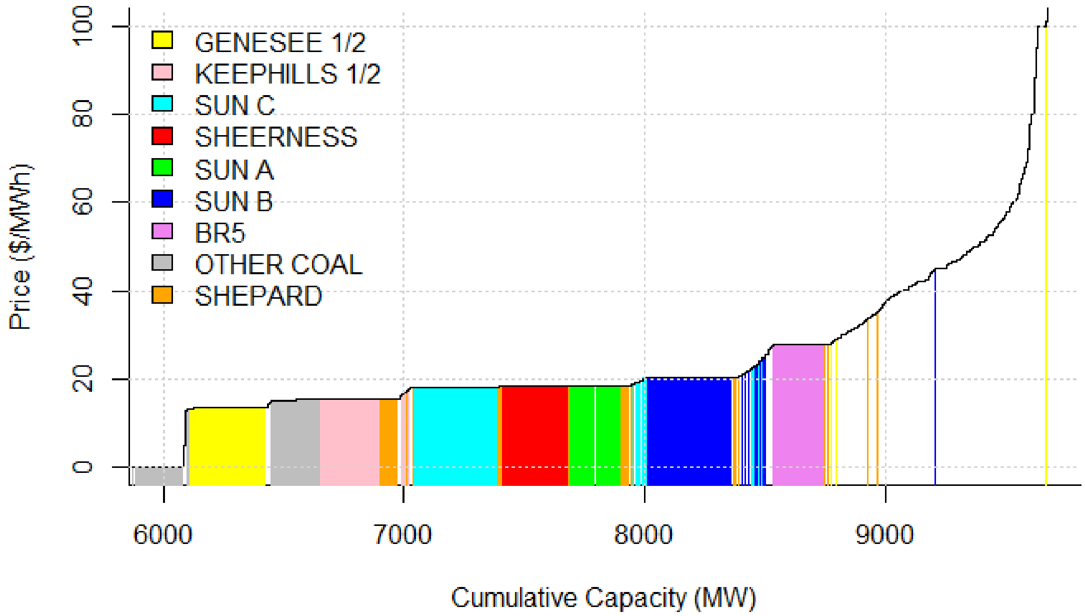


Figure 5: Quarterly Utilization by Fuel Type (Generation / Availability)

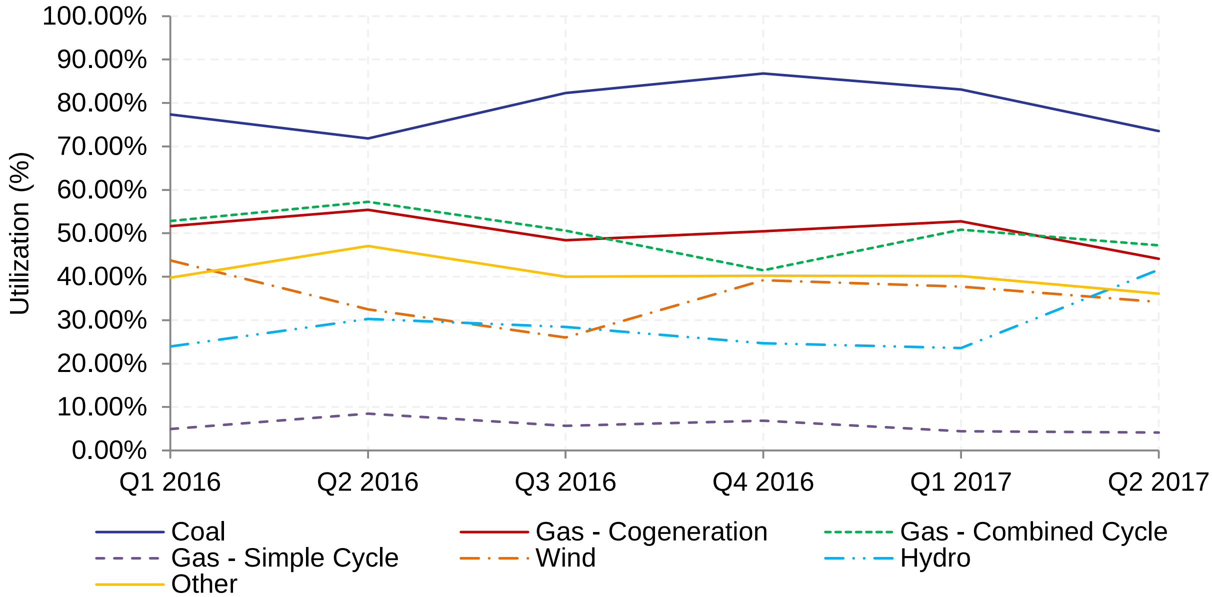


Figure 6: Daily Total Metered Volumes at Cogeneration Assets, 2016 – Q2 2017

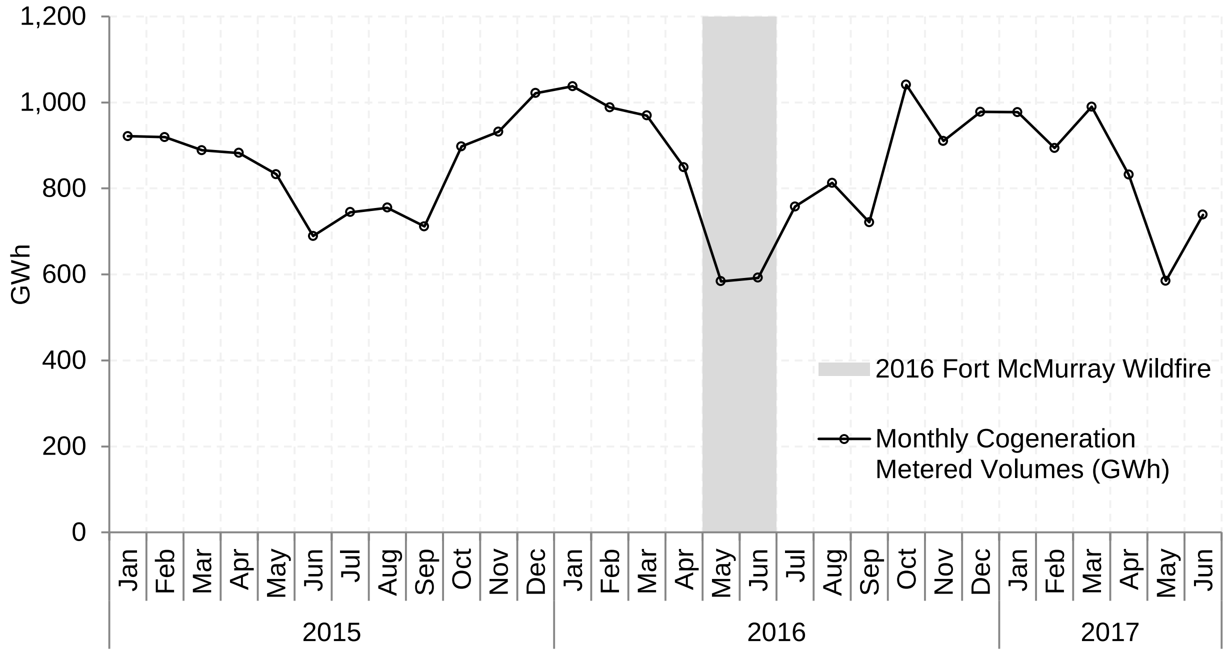


Figure 7: Aggregate Cogeneration Offers, Q2 2015-17 & Q1 2017

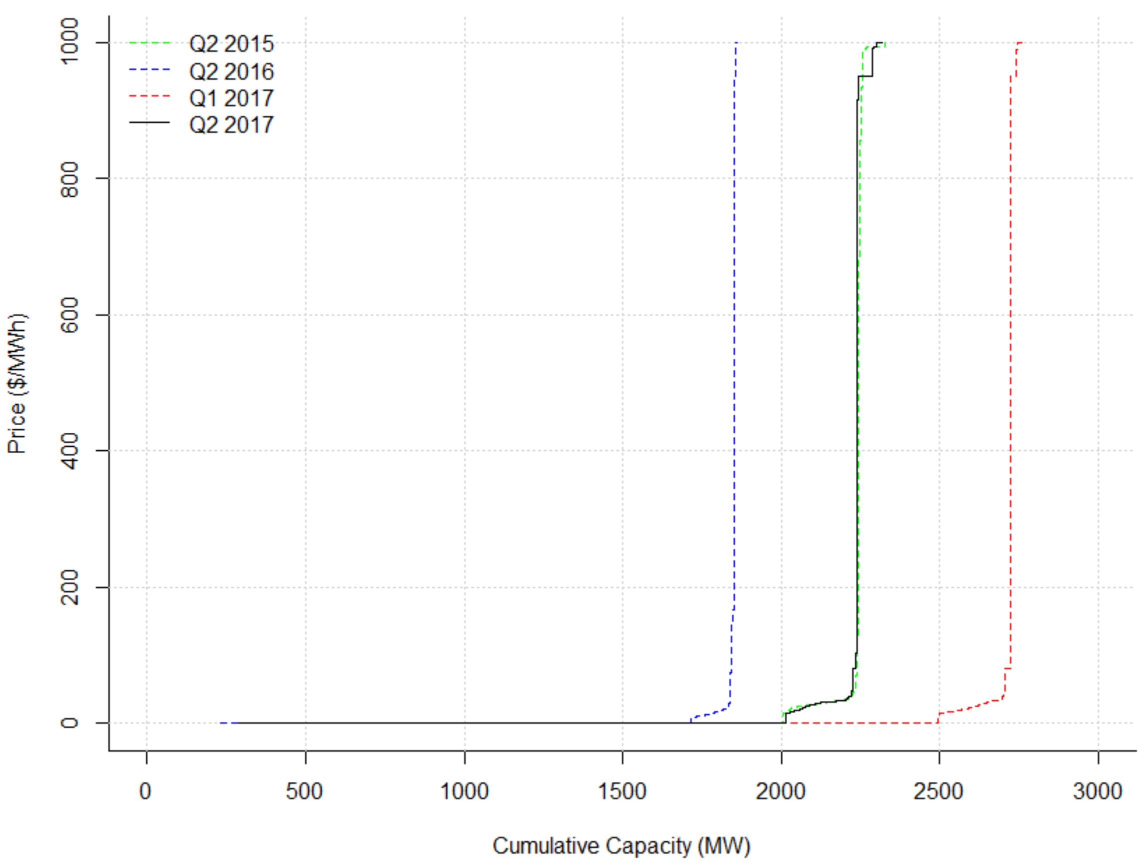
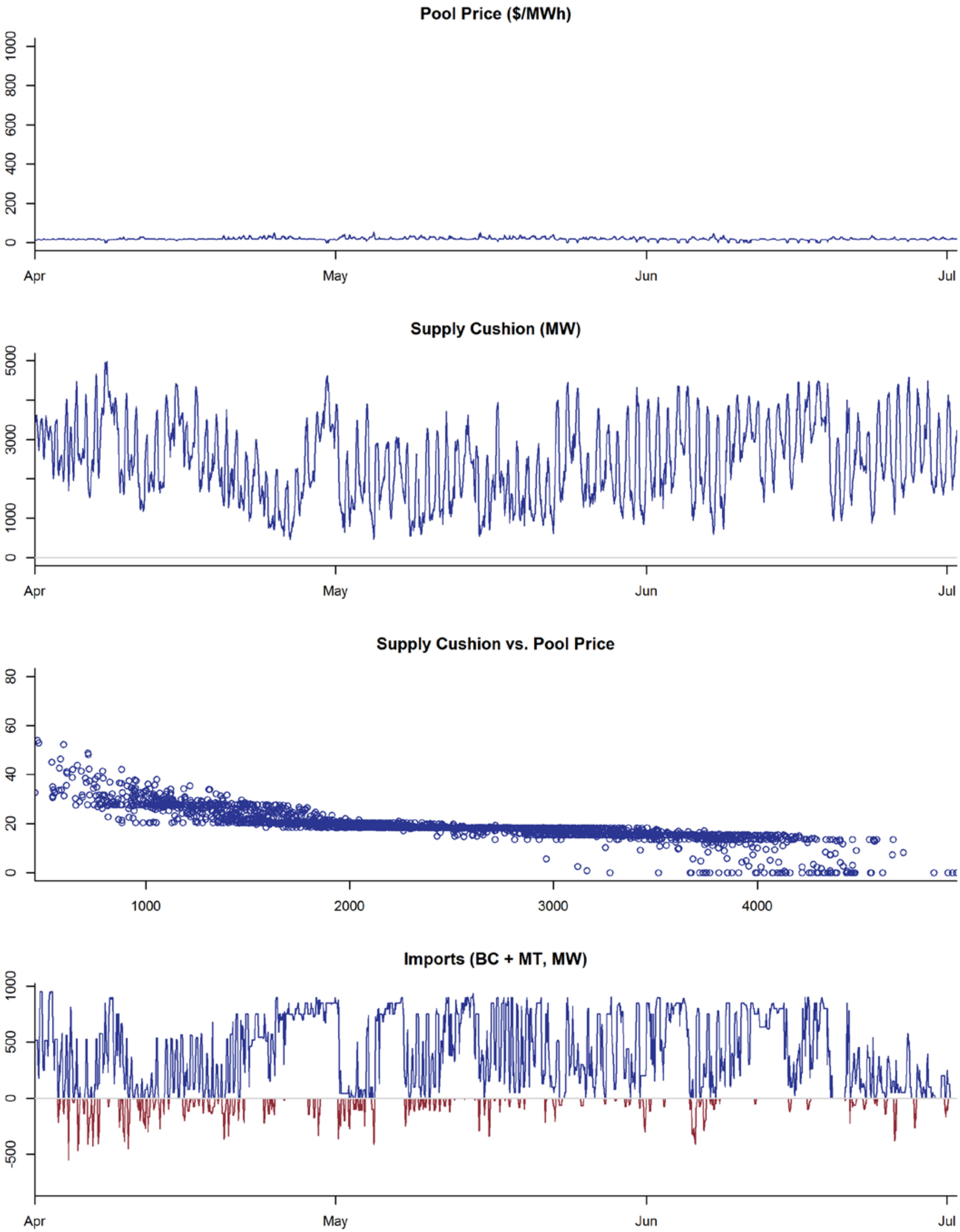


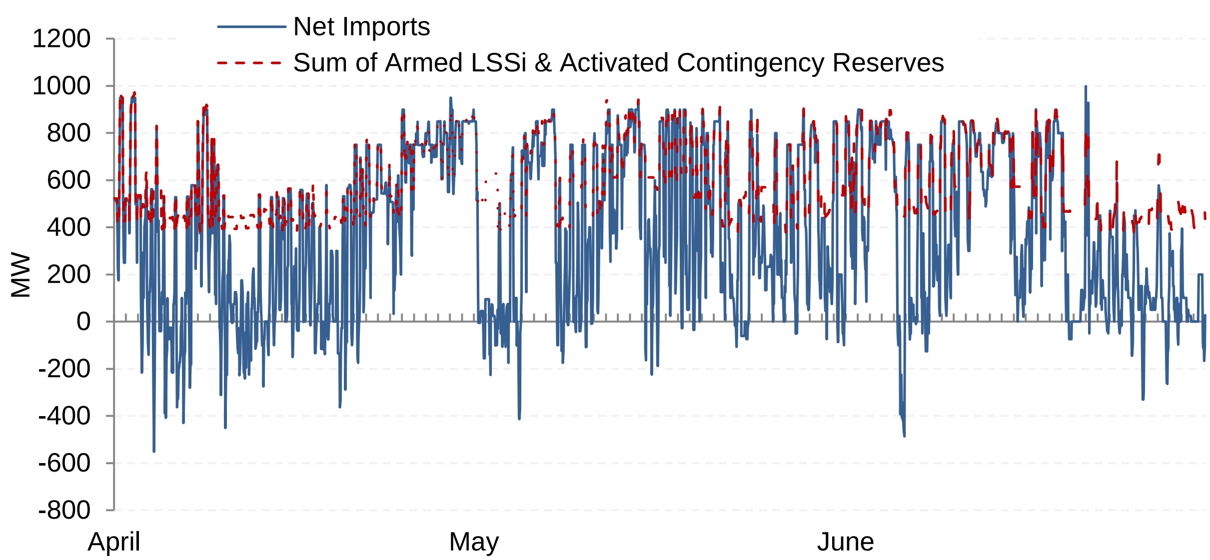
Figure 8: Q2/17 Summary Graphs



Imports

During the quarter, 836.5 GWh of net imports flowed into Alberta (4.7% of Alberta Internal Load), up from 96.5 GWh during the same quarter of the previous year. Alberta was a net importer in 82% of hours in the quarter. These large import volumes were primarily sourced from British Columbia, which experienced increased hydroelectric generation due to snowpack levels greater than the 1981-2010 average.[2] In order to facilitate these imports, the AESO procured an additional 213.8 GWh of contingency reserves, and armed 111.8 GWh of LSSi, at a total cost of $10.7 million. Together, this enabled a total of 285.1 GWh of imports into the Alberta system, earning $4.6 million in revenue from the energy market.

Figure 9: Q2 2017 Net Imports, Armed LSSi, Contingency Reserves[3]



In prior years, Alberta was typically a net importer in the second quarter of the year, with the bulk of net imports occurring in on-peak hours (HE 8 to 23). However, in Q2 2017, Alberta generally imported more during the average off-peak hours (Figure 10), compared to off-peak Q2 hours in prior years. This appears to have been caused by arbitrage motivated by low Mid-Columbia off-peak power prices relative to those in Alberta throughout the quarter (Figure 11 and Figure 12).

[2] Natural Resources Conservation Service, Mountain Snowpack for the Columbia River and Pacific Coastal Basins, April 2017, May 2017.
[3] Activated Contingency Reserve here means all Active Procured and Activated Standby Spinning and Supplemental Reserves.

Figure 10: Q2 Average Net Imports by Hour Ending, 2014-2017

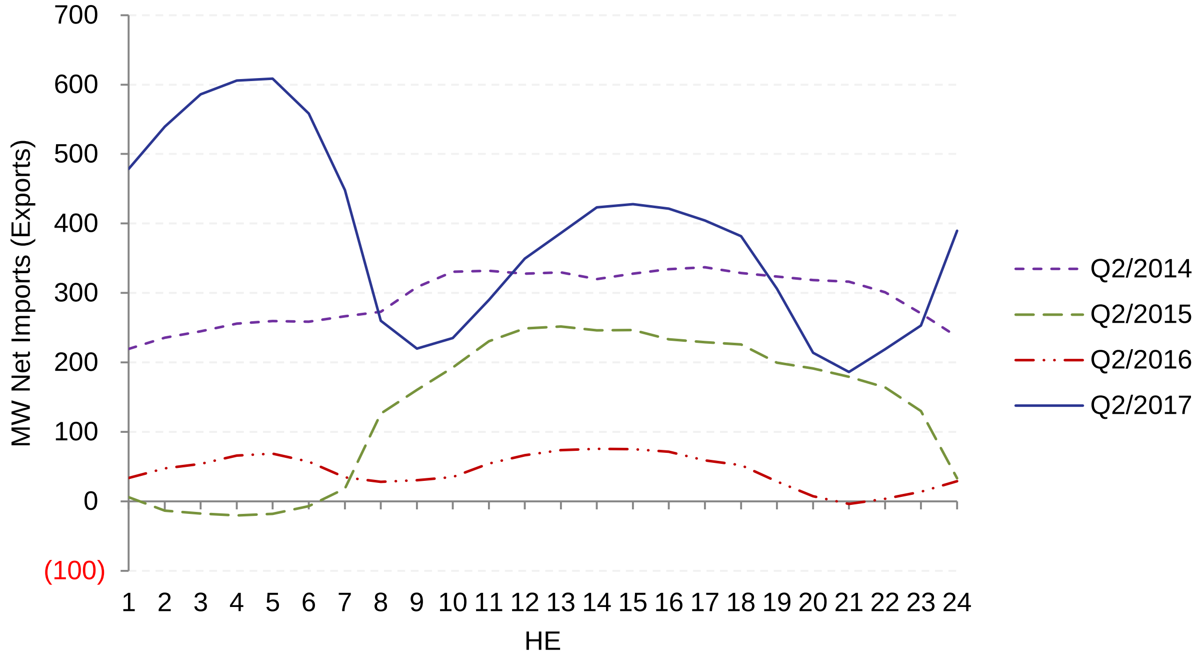


Figure 11: Q2 2017 Average Power Prices in Alberta and Mid-Columbia, by Hour Ending

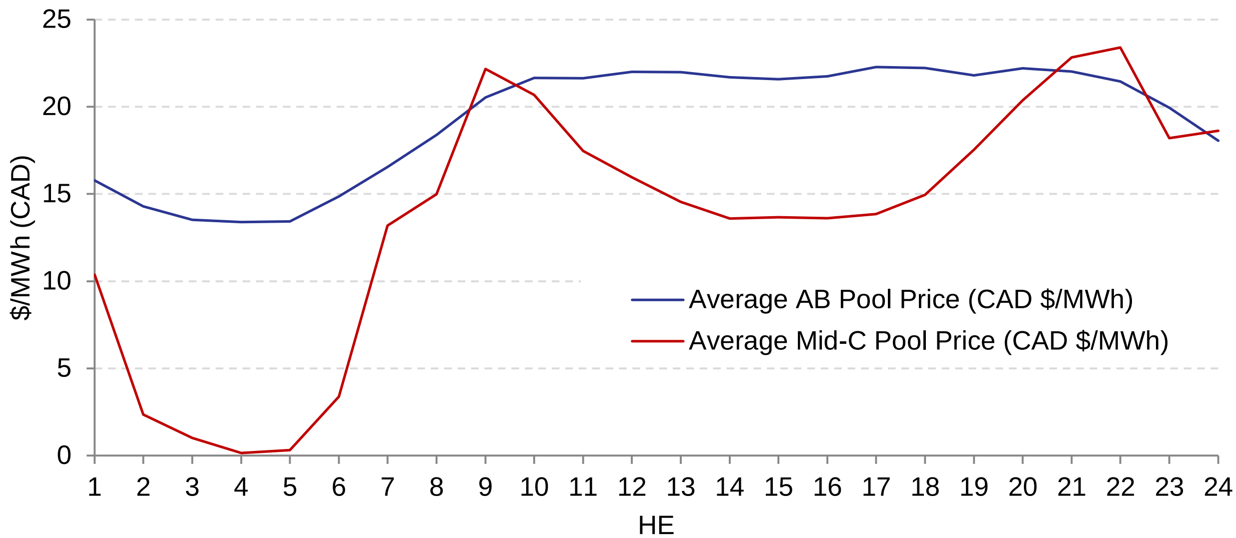
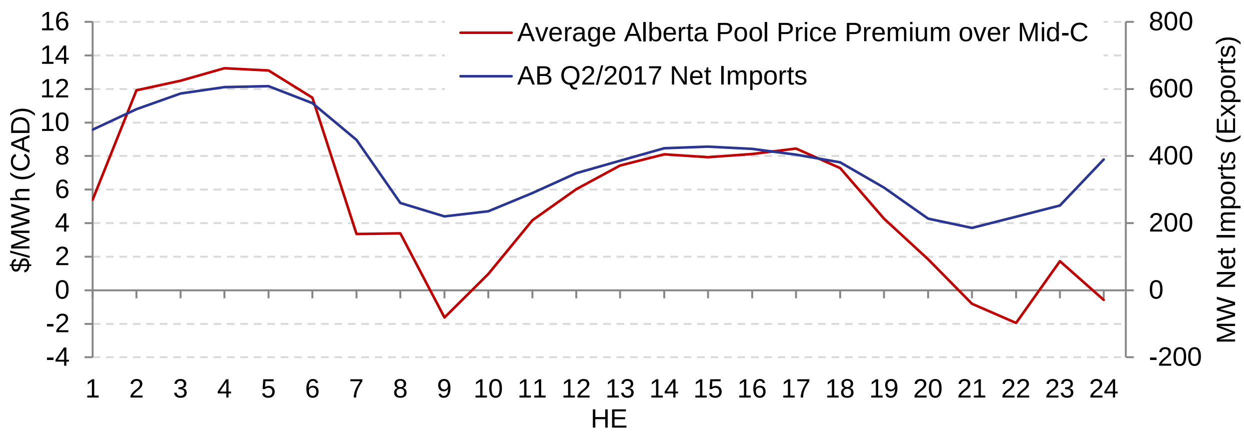


Figure 12: Q2 2017 Average Hourly Alberta Pool Price Premium over Mid-Columbia



Over the course of Q2 2017, net imports on the BC/MATL path during on-peak hours tended to align with arbitrage possibilities between the Alberta and Mid-C markets (Figure 13), primarily due to additional variability in the Alberta premium over Mid-C. Off-peak hour relative prices tended to favour importers more consistently (Figure 14).

Figure 13: Q2 2017 Alberta Pool Price Premium over Mid-C, On-peak (HE 8 to 23)

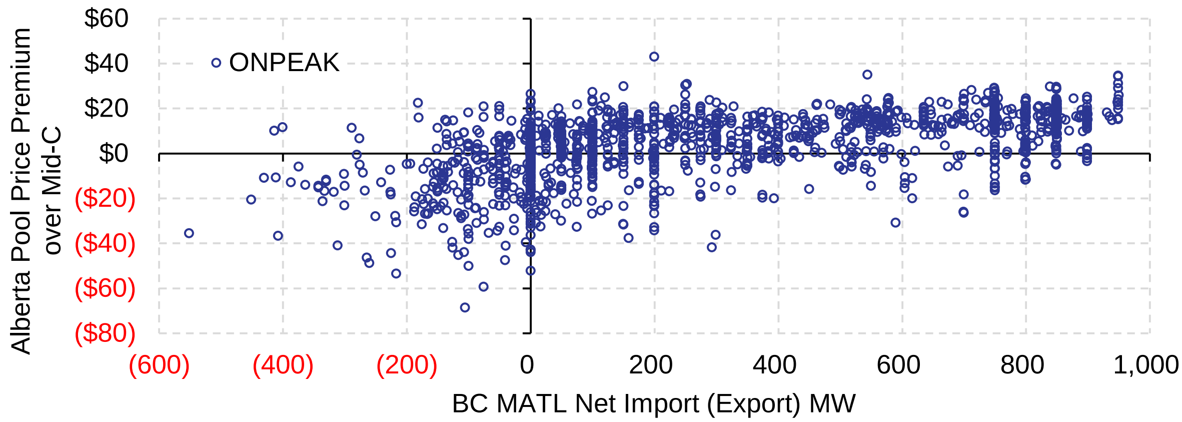
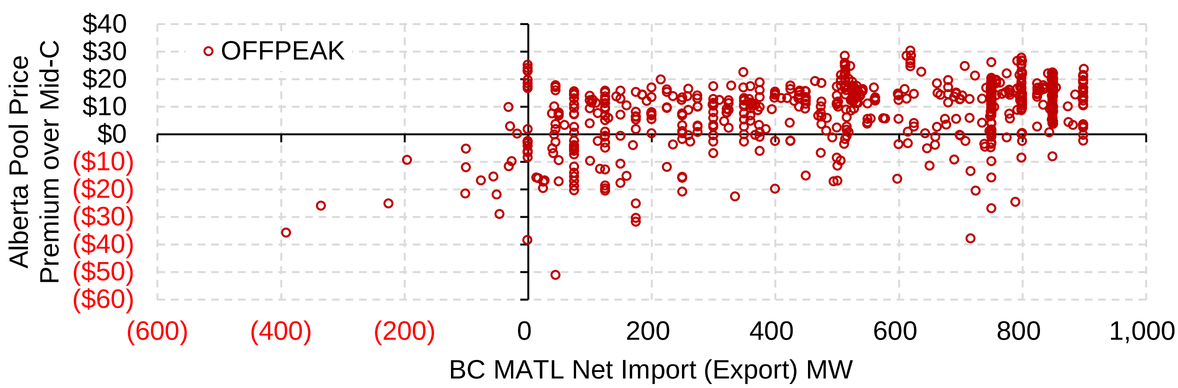


Figure 14: Q2 2017 Alberta Pool Price Premium over Mid-C, Off-peak (HE 1 to 7 and 24)



Import Enablement

Q2 2017 experienced considerably larger import volumes than in recent years, as explained in the Imports section above. As part of its mandate to maintain system reliability, the AESO must ensure that the system can withstand the loss of a single import tie line when imports are sufficiently high. This is accomplished using Contingency Reserve procurement and the arming of LSSi, The costs of import enablement are ultimately borne by electricity consumers.

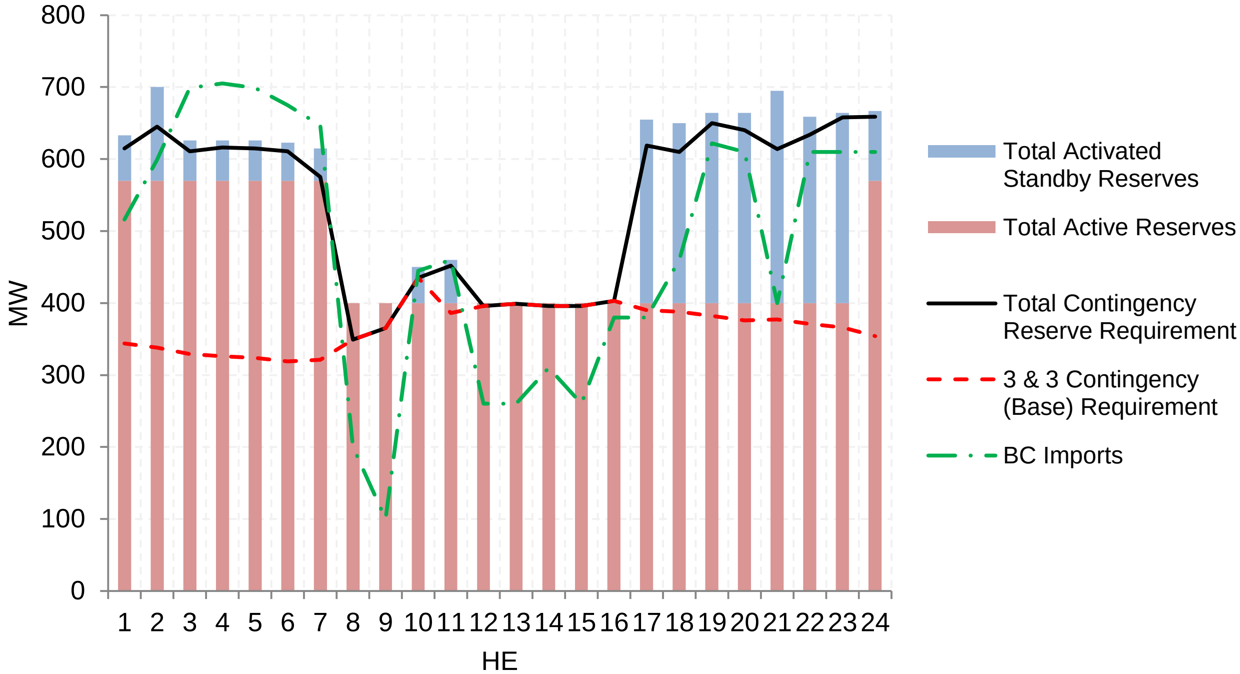
The Alberta Reliability Standard for Contingency Reserve states that the AESO must hold contingency reserves equal to either the loss of the Most Severe Single Contingency (MSSC), or 3% of the sum of load and generation (colloquially, the '3 and 3 Rule'), whichever is greater.[4] If imports are sufficiently high, an interconnection may be considered the MSSC, which may be greater than the 'baseline' established by the '3 and 3 Rule'. The minimum contingency reserves required from this calculation are filled using active spinning and supplemental reserve, or by activating standby spinning and supplemental reserves if the former is insufficient.

In 47% of hours in Q2 2017, the 500 kV Interconnection with British Columbia was the MSSC and was used to determine the minimum contingency reserve requirement in those hours. The MSA estimates that 213.8 GWh of contingency reserves were used to enable an equivalent quantity of imports (rather than those used to satisfy baseline requirements) at a cost of $5 million over the quarter. Of these contingency reserves, 127.7 GWh were provided using standby activations at a cost of $3.5 million, with the remainder coming from additional active spinning and supplemental reserves procured day ahead. For added perspective, 30% of the $16.8 million cost of contingency reserves in Q2 2017 stemmed from import enablement. Enabled imports earned $3.5 million in Alberta's energy market over the quarter.

For example, on June 17, 2017, the 500 kV Interconnection was the MSSC in HE 1 to 8, 11, and 17 to 24. Figure 15 shows how these hours typically had far greater contingency reserve requirements, with standby activations used to cover reserve requirements not filled by active procured spinning and supplemental reserves. To enable high import levels, 4.1 GWh of additional contingency reserves were used throughout the day.

[4] Alberta Reliability Standard Contingency Reserve – BAL-002-WECC-AB-2, July 26, 2015.

Figure 15: Contingency Reserve Requirement and Activated Reserves, June 17, 2017



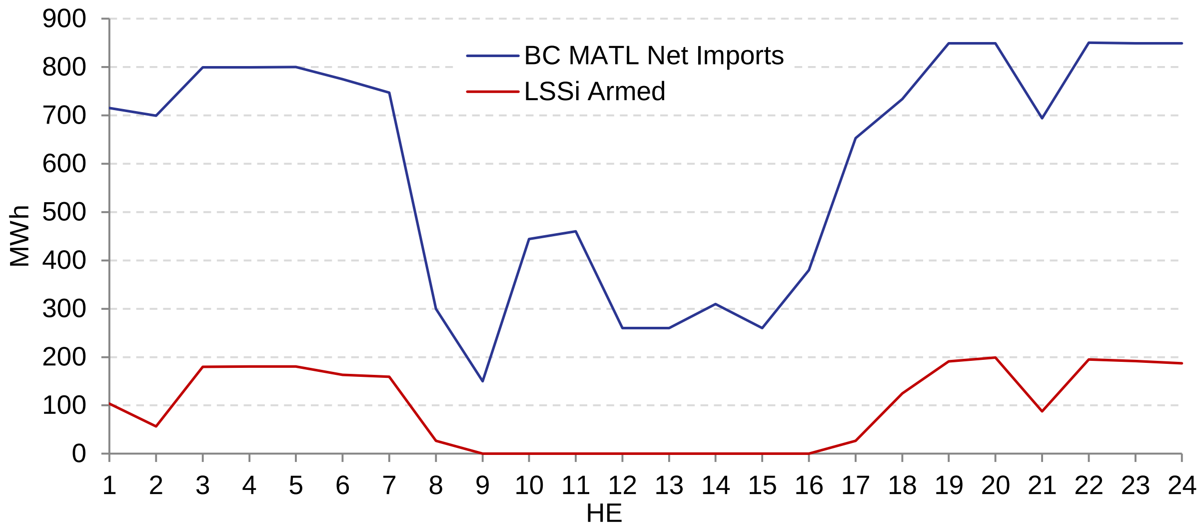
During the quarter, 118 GWh of LSSi was armed, at a total cost of $6 million. Of this, 111.8 GWh of LSSi was used to enable 71.2 GWh of Imports, at a cost of $5.7 million. These enabled imports earned $1.1 million revenue in the energy market.

For context, only 2.2 GWh of LSSi was armed in Q1 2017, at a cost of $113,000. No LSSi was armed in 2016.

LSSi arming requirements are set according to Alberta Internal Load (AIL) and the BC/MATL Net Import Schedule present at a given time.[5] LSSi is armed at specified net import levels in order to prevent under-frequency load shedding in the event of an intertie trip. An example of LSSi armings on June 17, 2017 is shown in Figure 16.

[5] AESO Average Transfer Capability and Transfer Path Management ID #2011-001R, June 15, 2017, Page 11.

Figure 16: Armed LSSi, BC MATL Net Imports, June 17, 2017

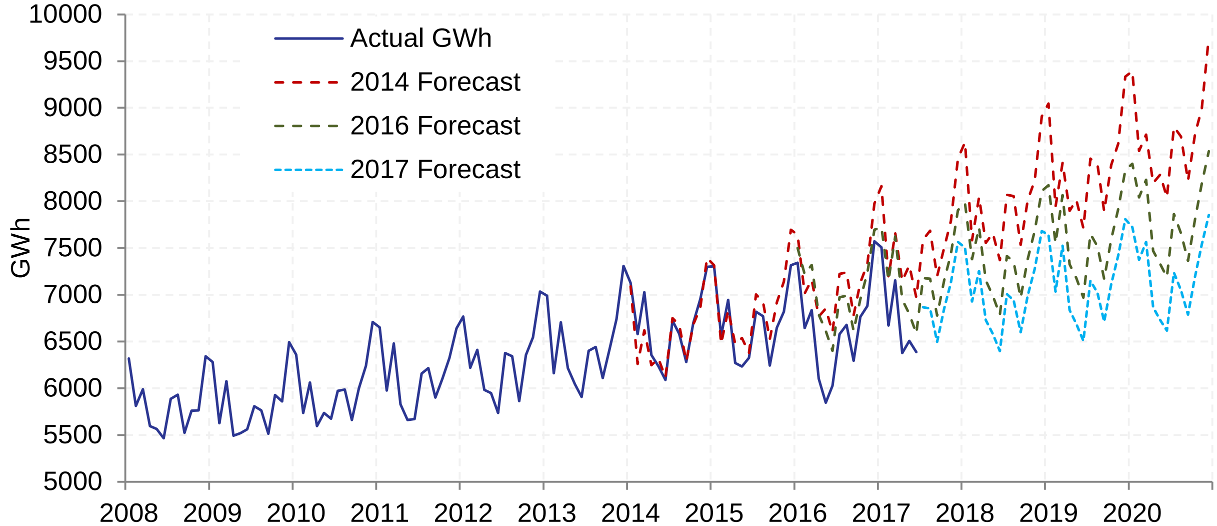


AESO 2017 Long-term Outlook

On July 20, 2017, the AESO released its 2017 Long-term Outlook, which provided an updated load and generation forecast for the next 20 years. Forecasts were conducted under seven potential generation and load scenarios, including a Reference Case.

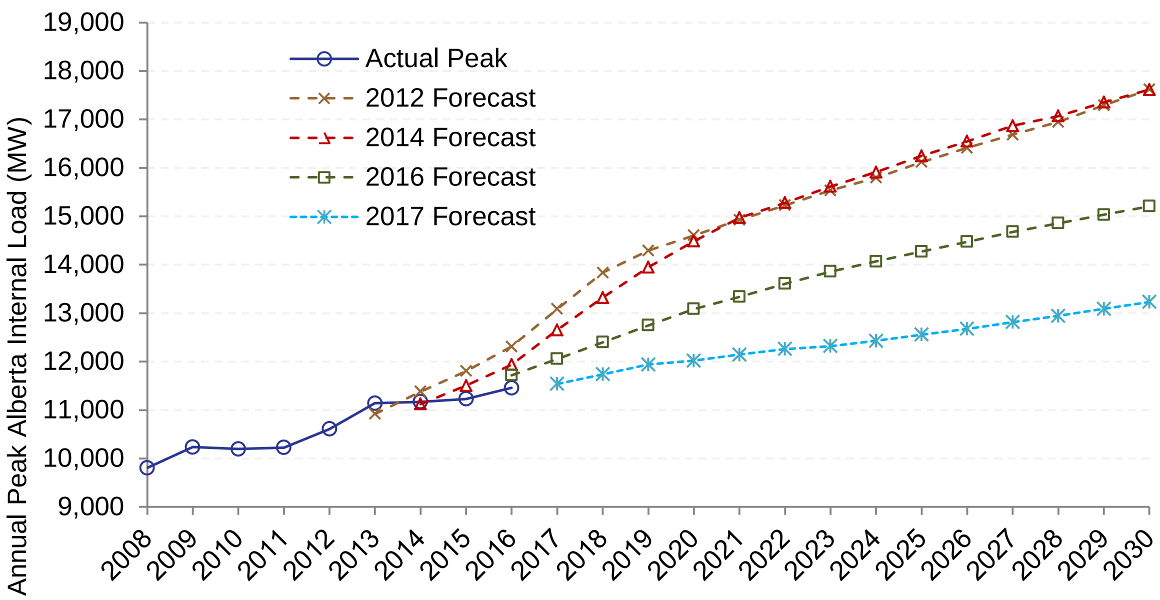
The Reference Case scenario revised down the load forecast made in the 2016 Long-term Outlook. The 2016 forecast estimated an annual average load growth rate of 1.6%, while the 2017 forecast Reference Case revised this down to 0.9%.This revision was primarily due to changes in economic indicators, but also due to changes in forecasting methodology, and the anticipated impact of energy efficiency programs.

Figure 17: Monthly Alberta Internal Load and AESO Main Outlook (2014) and Reference Case (2016, 2017) Long-term Outlook Demand Forecasts (GWh)[6]



The 2017 Long-term Outlook also lowered future annual peak load forecasts considerably as compared to that made in 2016; peak load forecasts from 2017 to 2030 were reduced by between 4 and 13%, compared to forecasts made in the 2016 Long-term Outlook.

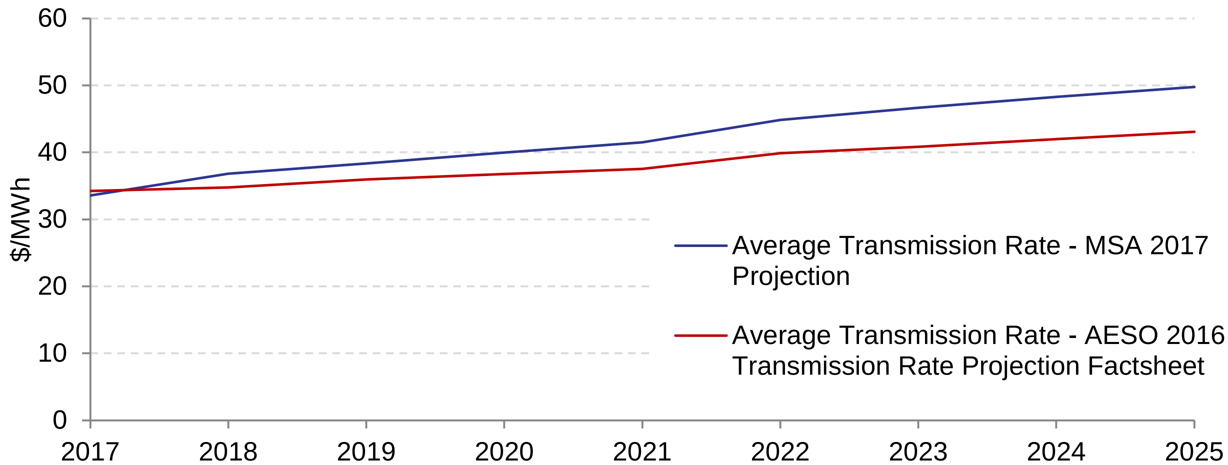
Figure 18: Annual Peak Alberta Internal Load (MW)[7]



[6] Forecast data available in the 2014 Long-term Outlook data file (May 30, 2014), 2016 Long-term Outlook data file (May 4, 2016) and 2017 Long-term Outlook data file (July 20, 2017). 2014 forecast data is from the Main Outlook scenario, while 2016 and 2017 forecasts are from the Reference Case scenario.
[7] 2012 Forecast data retrieved from the AESO 2012 Long-term Outlook. 2014 forecast data is from the Main Outlook scenario, while 2016 and 2017 forecasts are from the Reference Case scenario

Reductions in forecast load have implications for forecast transmission rates. Transmission infrastructure is built based on anticipated need, while the rates necessary to repay these costs are dependent on the actual future load. Figure 19 shows that if the 2017 Long-term Outlook load forecast holds, average transmission rates can be predicted to reach about $40/MWh by 2020, and $50/MWh by 2025, based on AESO transmission cost estimates. The average rate in 2016 was estimated to be $32/MWh. These rates would be 8.8% and 15.5% higher (respectively) than those predicted by the AESO in their 2016 Transmission Rate Projection factsheet, which were based on the 2016 Long-term Outlook load forecasts.

Figure 19: Revised Transmission Rate Projections incorporating 2017 Long-Term Outlook Load Forecasts



Forward Market

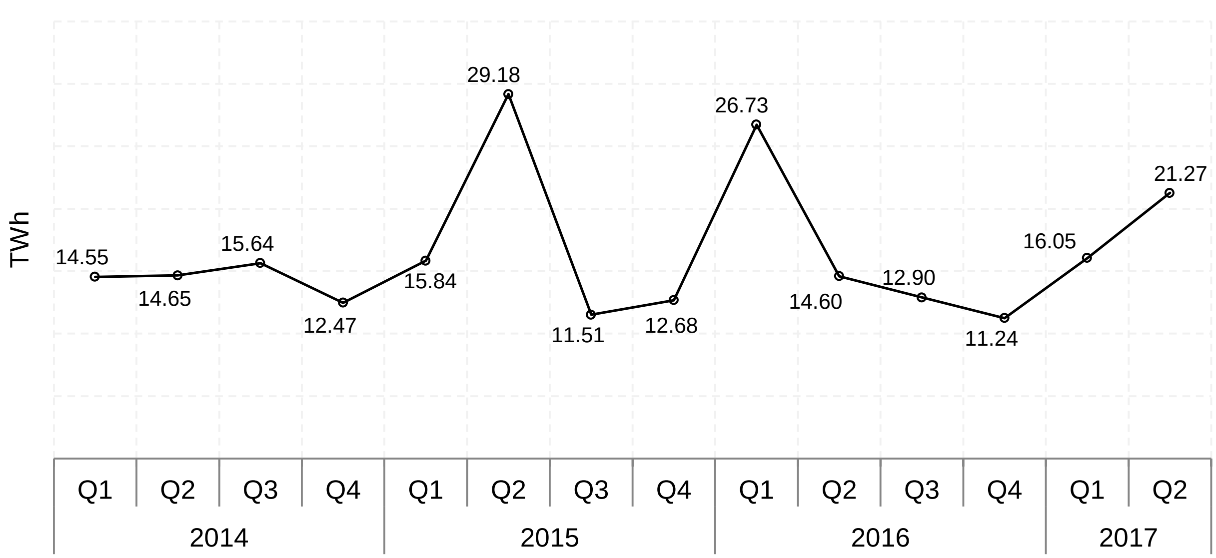
Forward market liquidity in Q2 2017 was up 32.5% over the first quarter, and 45.7% higher than Q2 2016. Traded volumes were 9% higher than the second quarter average since 2014. The majority of this increase was driven by annual forward volumes traded in April and May.

On April 19, 2017, a market participant announced its intention to retire one generating unit and mothball another beginning January 1, 2018, as well as its goal to convert four coal-fired units to gas-fired generation between 2021 and 2023. This announcement coincided with a significant increase in annual contracts traded.

Table 2: Trade Volumes by Contract Term (TWh)

		Daily	Monthly	Quarterly	Annual	Other	Total
2015	Q1	0.10	9.96	0.84	4.17	0.76	15.84
	Q2	0.20	10.46	1.14	16.71	0.66	29.18
	Q3	0.06	6.25	0.50	4.40	0.29	11.51
	Q4	0.06	5.87	0.98	5.74	0.03	12.68
	Year	0.42	32.54	3.46	31.03	1.74	69.20
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
	YTD	0.19	13.39	5.34	15.70	2.70	37.32

Figure 20: Total Trade Volumes over Time



Operating Reserves

Total operating reserve costs in Q2 2017 were similar to those in Q2 2016. However, regulating reserve costs fell, while spinning and supplemental reserve costs increased primarily due to increased volumes procured and activated.

Standby activations increased significantly year-over-year, often to enable imports from the U.S. Pacific Northwest.

Although more standby spinning and supplemental reserves were procured, the average standby premium paid for spinning and supplemental reserves decreased year-over-year. However, the increased procurement of standby supplemental reserves was sufficiently large as to increase the total cost of by 30% year-over-year, despite the reduction in average premium.

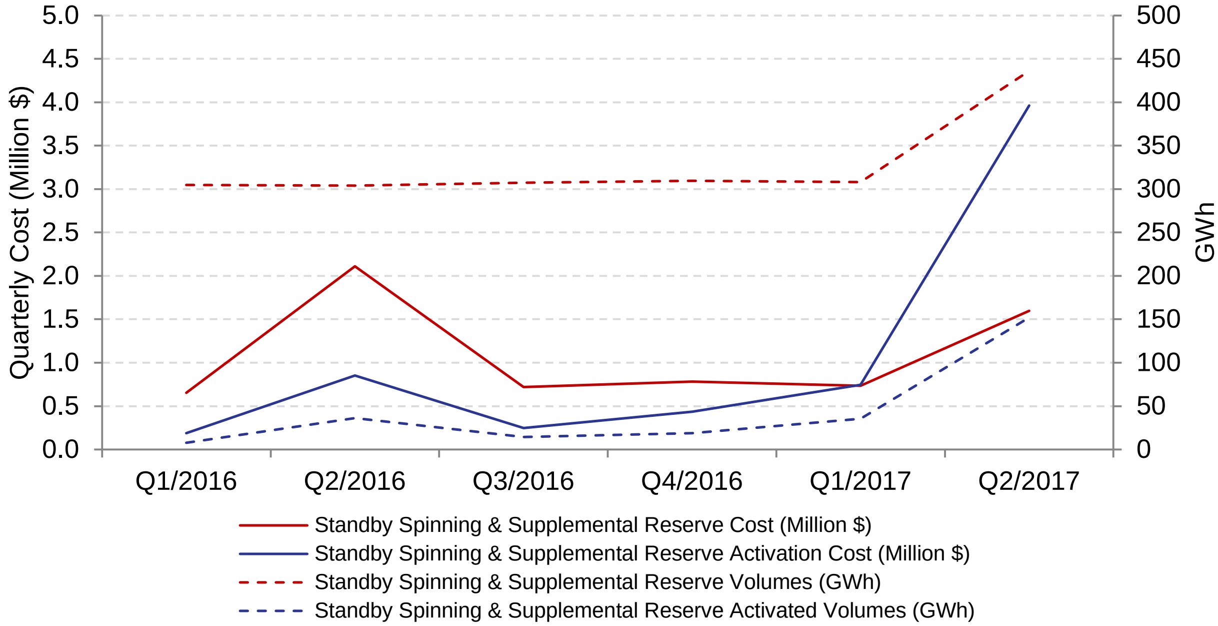
Table 3: Operating Reserve Summary

Total Cost ($ Millions)			
	Q2 2016	**Q2 2017**	***% Change***
Active Procured	**18.2**	**19.3**	***+6%***
RR	10.1	6.5	*-36%*
SR	5.7	9.4	*+64%*
SUP	2.3	3.4	*+48%*
Standby Activations	**0.9**	**4.1**	***+363%***
RR	0.0	0.1	*+311%*
SR	0.6	2.6	*+309%*
SUP	0.2	1.3	*+539%*
Standby Premiums	**6.3**	**2.4**	***-61%***
RR	4.2	0.8	*-80%*
SR	1.8	1.2	*-34%*
SUP	0.3	0.4	*+30%*
Total	**25.4**	**25.9**	***+2%***
Total Volume (GWh)			
	Q2 2016	**Q2 2017**	***% Change***
Active Procured	**1,231**	**1,370**	***+11%***
RR	340	342	*+1%*
SR	445	514	*+16%*
SUP	446	514	*+15%*
Standby Activations	**38**	**155**	***+313%***
RR	1	3	*+136%*
SR	25	90	*+255%*
SUP	11	62	*+472%*
Standby Premiums	**521**	**610**	***+17%***
RR	217	174	*-20%*
SR	228	293	*+29%*
SUP	76	143	*+88%*
Total	**1,789**	**2,135**	***+19%***
Average Cost ($/MWh)			
	Q2 2016	**Q2 2017**	***% Change***
Active Procured	**14.77**	**14.12**	***-4%***
RR	29.78	19.02	*-36%*
SR	12.91	18.34	*+42%*
SUP	5.17	6.63	*+28%*
Standby Activations	**23.47**	**26.28**	***+12%***
RR	20.59	35.87	*+74%*
SR	25.55	29.46	*+15%*
SUP	18.97	21.17	*+12%*
Standby Premiums	**12.13**	**3.99**	***-67%***
RR	19.40	4.82	*-75%*
SR	7.80	3.98	*-49%*
SUP	4.35	3.01	*-31%*
Total	**14.18**	**12.11**	***-15%***

Standby Spinning and Supplemental Reserves

The AESO procures standby reserves through a WattEx pay-as-bid auction. Units participating in the auction provide a premium price (received whether or not the unit is activated) and an activation price (received only if the unit is activated), which are combined by the AESO to create a blended price. This blended price is calculated as the sum of the premium price and 10% of the offered activation price. The 10% factor indicates the relative historical likelihood of a standby unit being activated. Blended prices are formed into a merit order and procured according to the AESO's daily standby requirements.

Figure 21: Quarterly Costs and Volumes of Standby & Activated Standby Spinning and Supplemental Reserves



Over the course of Q2 2017, the AESO procured and activated substantially more standby spinning and supplemental reserves at greater costs than in recent quarters (Figure 21). Standby procurement and activation costs for spinning and supplemental reserves in Q2 2017 were 60% and 700% higher than the average quarterly costs since Q1 2016 (respectively). Furthermore, quarterly activation rates for on-peak and off-peak spinning and supplemental reserves were considerably higher than the 10% activation factor used by the AESO to form blended prices (Figure 22 and Figure 23), primarily because of their use in import enablement.

Figure 22: Quarterly Spinning Reserve Activation Rates

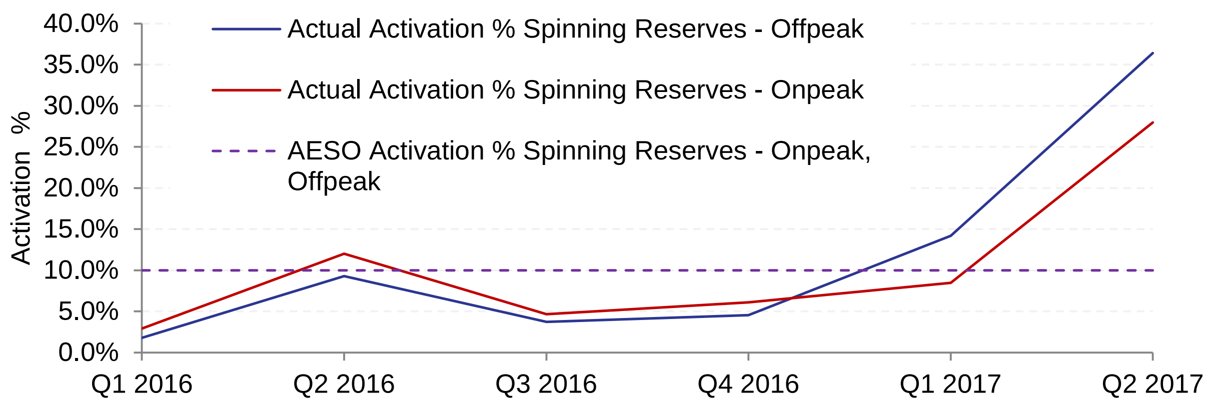


Figure 23: Quarterly Supplemental Reserve Activation Rates

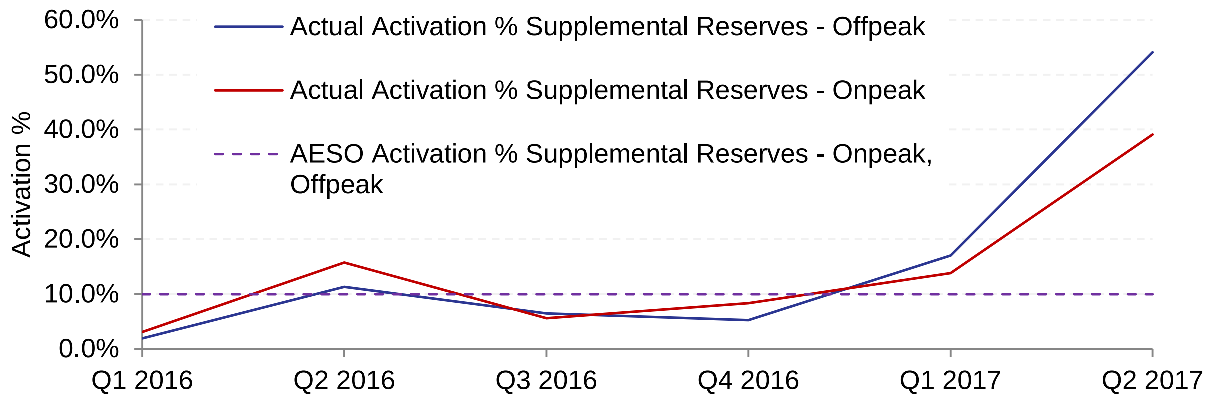


Table 4 illustrates the impact of these higher activation rates between the first two quarters in 2017; while the average standby activation price increased by 41% quarter over quarter, standby premium prices also increased by 54%.

Table 4: Standby Contingency Reserve Summary

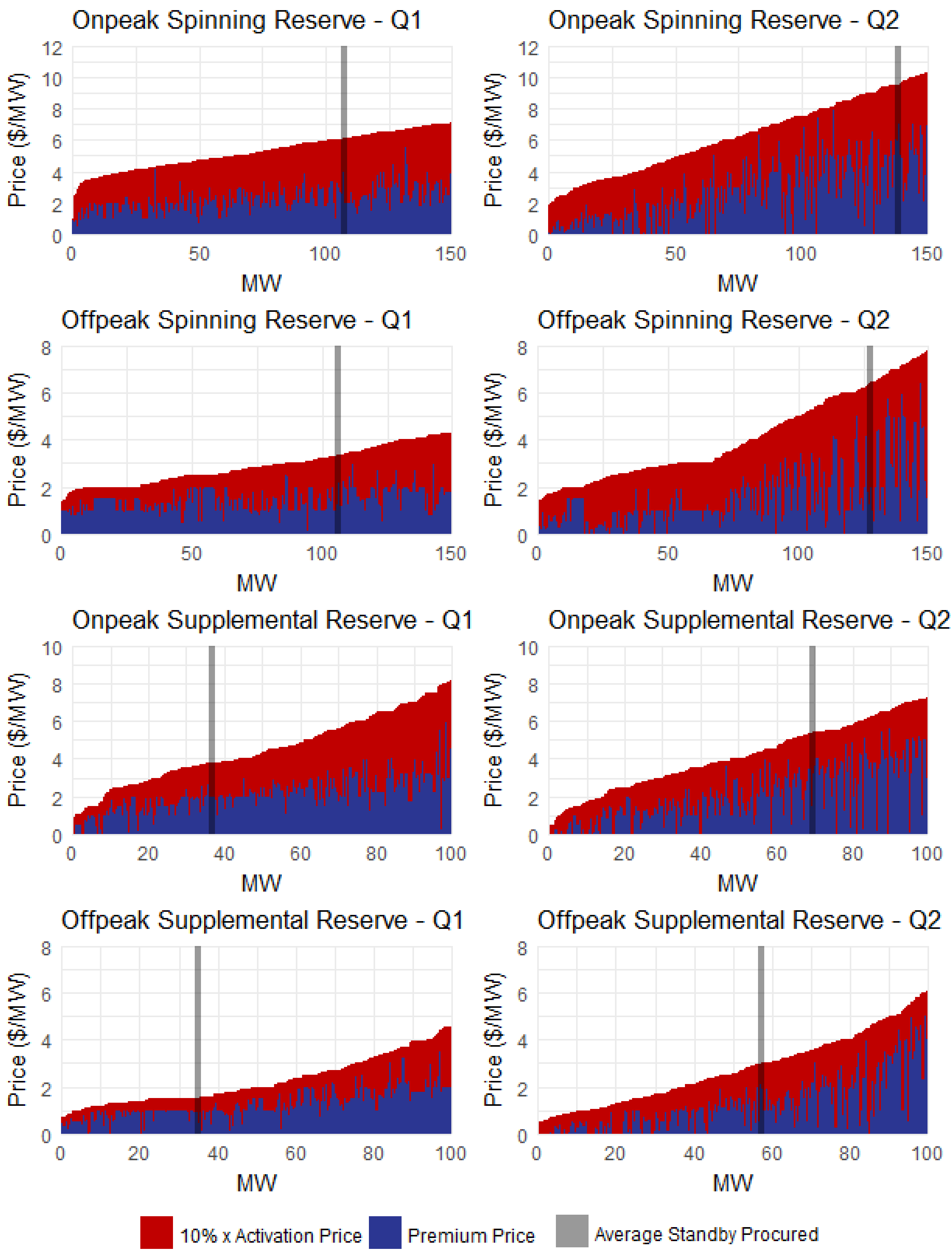
Total Volumes (GWh)			
	Q1 2017	**Q2 2017**	***% Change***
Standby Activations	**35**	**152**	***+329%***
SR – On-peak	13	56	*+330%*
SR – Off-peak	11	34	*+212%*
SUP – On-peak	7	39	*+441%*
SUP – Off-peak	4	23	*+428%*
Standby Procurement	**308**	**436**	***+42%***
SR – On-peak	154	201	*+30%*
SR – Off-peak	76	93	*+21%*
SUP – On-peak	53	101	*+91%*
SUP – Off-peak	25	42	*+67%*

Average Cost of ($/MWh)			
	Q1 2017	**Q2 2017**	***% Change***
Standby Activations	**21.31**	**30.14**	***+41%***
SR – On-peak	32.94	39.96	*+21%*
SR – Off-peak	14.48	28.21	*+95%*
SUP – On-peak	18.91	25.41	*+34%*
SUP – Off-peak	7.14	16.83	*+136%*
Standby Procurement	**2.38**	**3.66**	***+54%***
SR – On-peak	3.03	4.23	*+40%*
SR – Off-peak	1.72	3.41	*+98%*
SUP – On-peak	2.14	2.74	*+28%*
SUP – Off-peak	0.94	3.67	*+291%*

The MSA conducted an analysis to determine if standby offer behaviour had been influenced by the higher ‘true’ activation rate. Because the standby merit order is ranked by blended price, when the ‘true’ activation rate is greater than the 10% used to calculate blended price, units have a greater incentive to increase their activation price offer and decrease their premium price offer at a 10 to 1 rate. The MSA was interested in understanding whether the increase in the average standby activation cost was on account of such a change in offer behaviour. Average standby activation costs are higher than their procurement cost, so this behaviour would increase total contingency reserve costs when activation rates are high, as was the case in Q2 2017. To test this hypothesis, aggregate merit orders ranked by blended price were constructed for on-peak and off-peak spinning and supplemental reserves in Q1 and Q2 2017.

The results of this analysis are presented in Figure 24. Although increased activation price offers are noticeable in the off-peak spinning and supplemental standby reserve markets between quarters, the merit orders also illustrate the effect of additional standby procurement on prices. The additional volumes procured between quarters could only be procured at higher blended prices, generally comprised of both higher activation and premium prices. It is also worth noting that activation rates were 10% higher for off-peak standby products compared to on-peak products; this may explain why offer behaviour in the off-peak standby product auctions was more affected by actual activation rates for Q2 2017.

Figure 24: Aggregated Standby Reserve Merit Orders, Q1 & Q2 2017



Activation Rate Counterfactual

Despite finding a limited effect of ‘true’ activation rates on standby offer behaviour, the MSA was interested in determining if any benefits could be gleaned from changing the 10% activation factor used to create blended price offers into one that mirrors the ‘true’ activation rate for the standby product. To assess this, the MSA constructed a counterfactual for June 17, 2017, wherein the standby spinning and supplemental reserve auctions for that particular delivery date were adjusted so as to make use of the actual activation rate for that product in calculating blended price offers, rather than using the 10% activation factor (Table 5). The auctions were then re-run mechanically using the counterfactual blended price values, with procured standby units activated according to offered activation prices.

Table 5: June 17 2017 Activation Rates for Standby Spinning and Supplemental Reserve Products

Standby Reserve Type	**AESO Activation Rate (used in Blended Price Calculation)**	**Actual June 17th Activation Rate**
Off-peak, Spinning Reserve	10%	40%
On-peak Spinning Reserve	10%	35%
Off-peak Supplemental Reserve	10%	85%
On-peak Supplemental Reserve	10%	45%

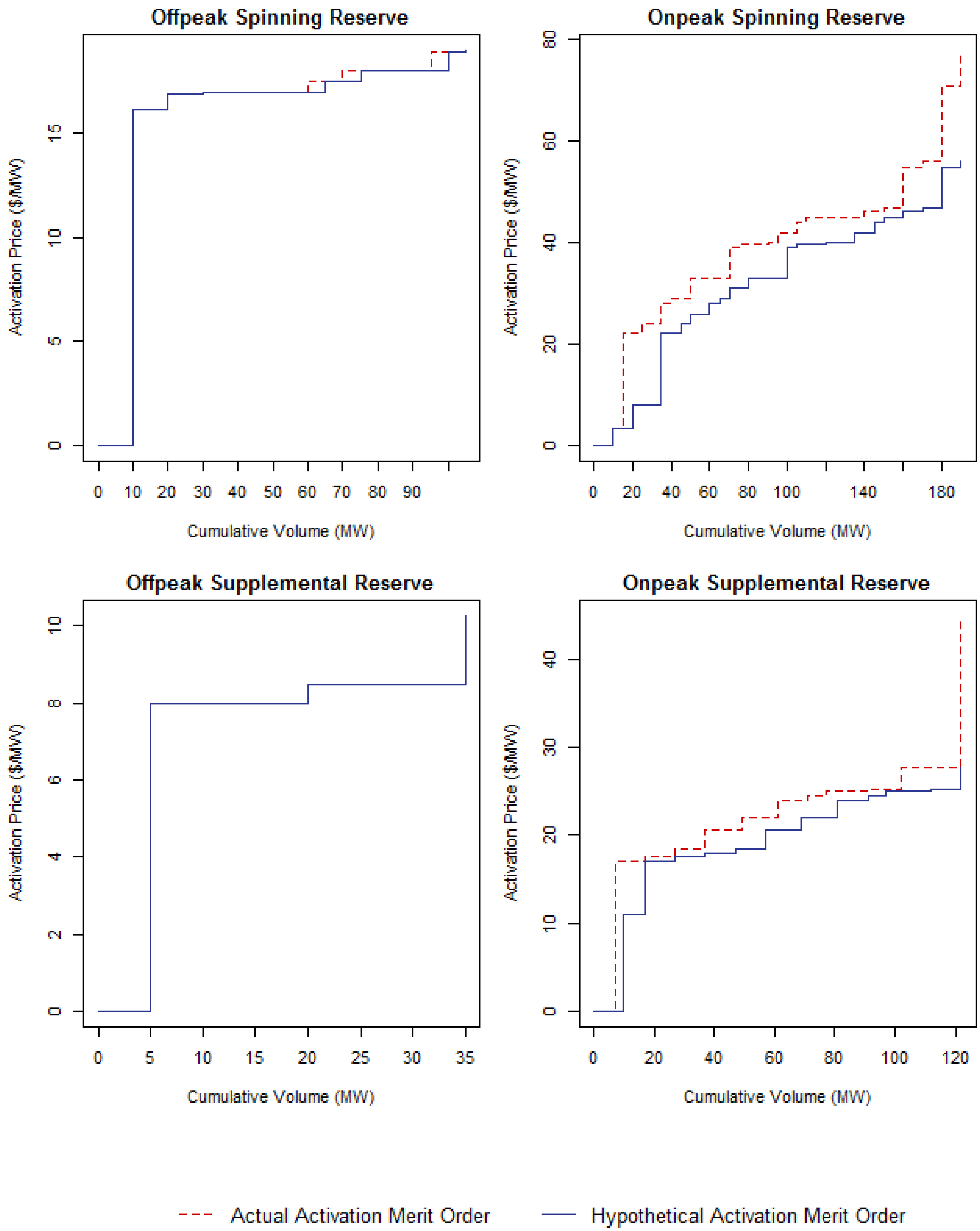
The results of the counterfactual are shown in Table 6 and Figure 25 below. The use of the higher activation rates in the counterfactual blended price more favourably impacted units with higher premium price offers, but lower activation price offers when compared to the actual standby auction. As a result, more units with lower activation prices were procured in the counterfactual WattEx auction, but at the cost of a greater expenditure on standby premiums.

Table 6: Activation Rate Counterfactual Cost Impact, June 17, 2017

	Standby SR and SUP Costs with 10% Activation Rates (Actual)	Standby SR Costs with Actual Activate Rates (Counterfactual)	*Additional Costs (Savings) using Actual Activation Rates*
Total Premium Cost	$15,026.32	$21,457.52	+$6,431.20
Total Activation Cost	$67,713.45	$55,719.25	($11,994.20)
Total Standby Cost	$82,739.77	$77,176.77	**($5,563)**

Generally, procured standby units are activated according to their activation price offer in the initial WattEx auction, depending on the need for activated standby. Because the use of the actual activation rate resulted in more procured units with lower activation prices, standby products procured in the counterfactual scenario could more often be ‘activated’ at a lower activation price. These activation merit orders are shown in Figure 25.

Figure 25: Standby Contingency Reserve Activation Merit Order, June 17, 2017

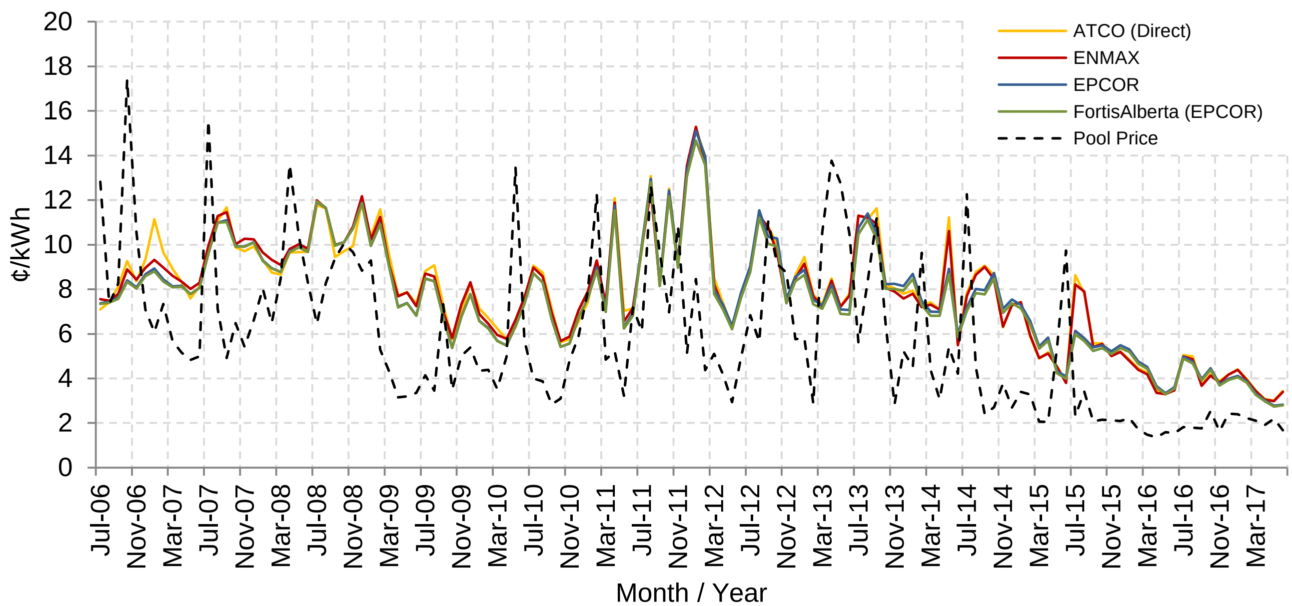


The results of the counterfactual show that had the AESO used the actual activation rate in the blended price calculation for June 17, 2017 standby spinning and supplemental procurement, standby premium costs would have increased, but activation costs would have decreased by a greater amount, for a net savings of $5,563. It should be noted that this counterfactual assumed foreknowledge of activation rates for each product across the day, which is not a realistic forecasting expectation. Additionally, this analysis does not account for any change in offer behaviour that could result from any made to the activation factor. Nevertheless, there is some indication that adjusting the activation factor in standby spinning and supplemental reserve auctions when the likelihood of actual activation is high may yield cost savings.

Retail Market

RRO Rates generally continued to fall in the second quarter of 2017, with residential rates in all four service areas reaching record lows ranging from 2.744 to 3.016 ¢/kWh in May 2017. These low rates remain consistent with fundamentals in the energy and forward markets.

Figure 26: Residential RRO Rates and Pool Price

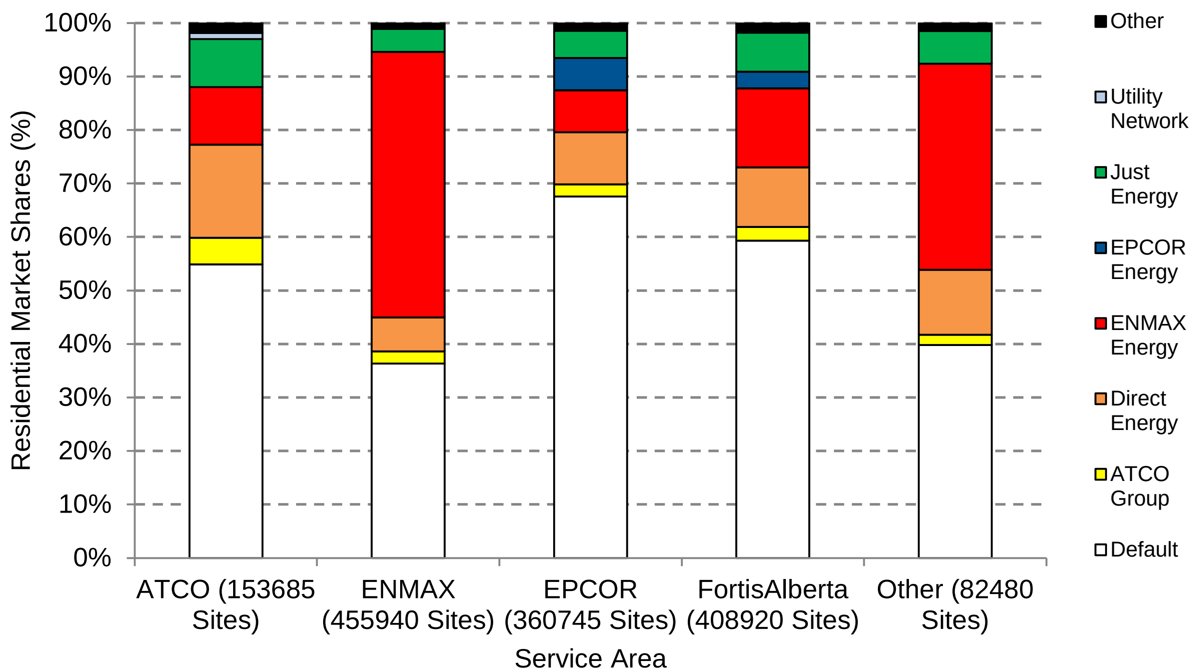


Retail Market Statistics

In June 2016 the MSA began a consultation regarding changes to its publication of retail market data. On June 22, 2017, the MSA published stakeholder comments and responses, and indicated its intention to implement the changes. The MSA provided market participants who are named in the statistics notice under Section 6(4) of the *Market Surveillance Regulation* and received written objections from two market participants. The MSA filed two applications with the Alberta Utilities Commission (AUC), one for each objection. The AUC published its decision in Proceeding 22774 on July 12, 2017 and 22789 on July 21, 2017. Both AUC decisions allow the publication of the names of the objecting market participants after concluding that the determination made by the MSA to name the objecting market participants is reasonable. The new report was posted to the MSA's website in conjunction with this report, under the "Retail Statistics" tab.

The MSA plans to regularly publish graphs showing retail electricity and natural gas market shares using the Retail Statistics. Figure 27 shows retail electricity market shares for residential electricity customers. Additional market share figures are available in Appendix A.

Figure 27: Retail Electricity Market Shares, Residential Customers, March 2017



MSA Report – Options for Enhancing the Design of the Regulated Rate Option

On April 18, 2017 the MSA received a letter from the Minister of Energy requesting that the MSA prepare a report on options to enhance the design of the RRO. The MSA published this letter and a request for comments on April 21, 2017. The MSA received comments from 20 stakeholders. The MSA published a draft report on June 20, 2017. Additional comments were requested by July 18, 2017. Comments were received from 12 stakeholders. The MSA will publish a final version of the report in the coming weeks.

Price Cap Regulation

On November 22, 2016 the Government of Alberta announced that RRO rates will be capped at 6.8 cents per kWh from June 2017 to June 2021. This policy was put into effect with the passing of *An Act to Cap Regulated Electricity Rates* (Cap Act). The implementation of the policy for municipalities and rural electrification associations that are owners as defined in the Cap Act (Providers) was effected by the *Rate Cap (Board or Council Approved Regulated Rate Tariffs) Regulation* (Cap Regulation).

The Cap Regulation designates the MSA as the approving body for deferral account statements, which are required to be submitted to the Minister of Energy after approval so that the Providers can receive compensation. The Cap Regulation provides that the MSA may determine the process by which it approves a deferral account statement. The MSA will be consulting with Providers on its proposed process in the coming weeks.

Other Activities

Offer Behaviour Enforcement Guidelines

On May 26, 2017, the MSA revoked the Offer Behaviour Enforcement Guidelines (OBEG).

The revocation of the OBEG is not a prohibition on economic withholding; rather, revocation is a signal to the market that the MSA will look closely at offer behaviour and efficiency in the context of the legislative framework during the transition to a capacity market. The MSA is of the view that the transition poses some challenges. The MSA is open to discussions with market participants about how best their concerns during the transition period could be addressed through fostering greater competition.

The rationale for the MSA's former approach to economic withholding as set out in the OBEG—conduct that often resulted in static efficiency losses—required that there be corresponding dynamic efficiency gains from innovation and investment, and thus a net efficiency gain over time that resulted (or was likely to result) from the forces of competition. Having considered the feedback from stakeholders, the MSA is still concerned that certain market participant conduct that results in static efficiency losses would now not result in dynamic efficiency gains from innovation and investment. Further the MSA is not convinced that there is an alternate rationale that would leave the OBEG unchanged.

The MSA also considered whether to maintain other parts of the OBEG that did not deal with economic withholding. There was considerably less feedback on these parts of the OBEG. While the MSA is not convinced the current sections should be maintained, it is open to further discussion with stakeholders on whether some parts of the OBEG in modified form could form part of a new guideline. Further, some stakeholders found parts of the OBEG useful in setting out the MSA's general enforcement stance, separate from guidance on specific topics. The MSA is also open to feedback on this issue and is of the view that setting out the MSA's general enforcement approach can be done separate from a guideline made under section 39(4) of the *Alberta Utilities Commission Act* (AUCA).

The complete set of documents related to this consultation is available on the MSA's website.

Historical Trading Report

On May 17, 2017, the AUC released Decision 21115-D01-2017 (Decision) which concerned the publication of the Historical Trading Report (HTR) by the Alberta Electric System Operator (AESO). Proceeding 21115 followed from an application that the MSA brought before the AUC on December 2, 2015.

In the Decision, the AUC instructed the AESO to cease publication of the HTR as soon as practicable, and by no later than 11:59 p.m. on Tuesday, May 23, 2017. The HTR was removed, in its entirety, from the AESO's website on May 18, 2017.

In June 2017, several parties to the Proceeding applied for permission from the Court of Appeal of Alberta to appeal the Decision. In July 2017, several parties to Proceeding 21115 applied to the AUC for review and variance of the Decision. The AUC has formed Proceeding 22797 to consider these applications.

Self-Reports regarding the sharing of dispatch information

The MSA received two self-reports regarding contraventions occurring in April where a market participant communicated dispatch instructions to a plant operator of a different asset than the one dispatched by the AESO. In both incidents, the assets are not affiliated with one another. Therefore, the erroneous sharing of the dispatch information is a violation of section 3(1) of the Fair, Efficient and Open Competition Regulation. The MSA found no evidence of an impact to the wholesale electricity market resulting from the shared information and in these instances declined to investigate.

Planned Outages (24 months)

In its Q1 2016 Report, the MSA considered whether outage records that related to outage planned for a period more than two years in the future could be material. The MSA stated "[i]n some circumstances the MSA believes such records may be material, for example in the case of a significant unit refurbishment, retirement or a combination of outage records. On June 22, 2017 the AESO updated section 3.2(a) of information document to state:

> Note that the AESO is currently assessing whether there are circumstances in which outage records beyond twenty four (24) months may be material. Depending on the outcome of this assessment, the AESO may implement a process for market participants to provide an outage schedule for planned outages beyond twenty four (24) months for publication by the AESO.

The MSA maintains the view that in certain cases records relating to outages beyond 24 months may be material and should not be traded on prior to being made public by the AESO.

Entering Mothballing Outages in ETS

In May 2017 the MSA received a letter from a market participant stating that, as an agent for another market participant, it had tried to enter outage information in ETS that related to a period after the expiry of the agency arrangement. The market participant was not able to enter this information through ETS and the information was instead provided by the principal to the AESO directly. The MSA believes that the AESO's systems should accommodate the entry of outage information by either the principal, or where applicable an agent, even if the outage information extends beyond the term of the agency arrangement.

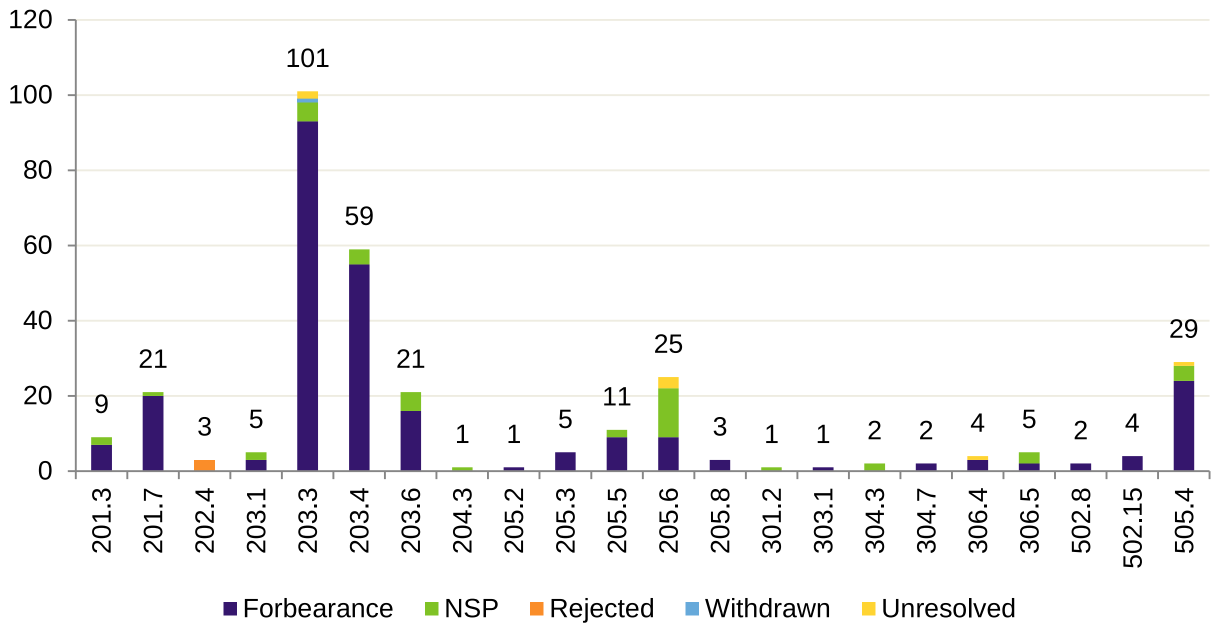
2017 Market Share Offer Control Report Errata

On May 11, 2017, the MSA published its annual Market Share Offer Control Report. The Market Share Offer Control Report stated that the VQ6 asset retired between 2016 and 2017. It was brought to the MSA's attention that the asset was still active and producing power. The MSA found that the asset did not retire, but the maximum capability of the asset decreased from 6 MW to a very small amount. This does not change the total generation capacity in Alberta as reported in the Market Share Offer Control Report.

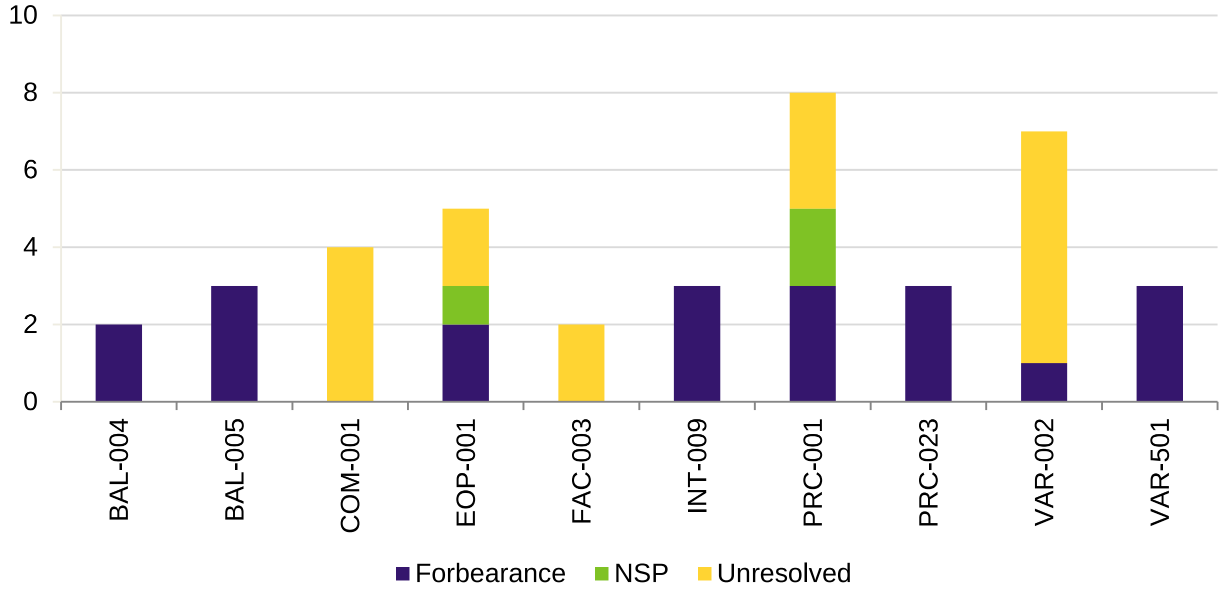
Compliance

Through enforcement of ISO rules and reliability standards the MSA contributes to the reliability and competitiveness of the Alberta electric system and promotes a culture of compliance and accountability among market participants.

The purpose of ISO rules is to promote orderly and predictable actions on the part of market participants and to support the role of the AESO in coordinating those actions. From January 1 to June 30, 2017, the MSA addressed 308 ISO rules compliance matters, while seven remained unresolved. Forty-five of the 308 closed matters resulted in notices of specified penalty, totalling $59,000 in financial penalties.



The purpose of Alberta Reliability Standards is to ensure the various entities involved in grid operations (generators, transmission operators, and the AESO) are doing their part by way of procedures, communication, coordination, training, and maintenance, among other practices, to support the reliability of the interconnected electric system. For Alberta Reliability Standards, the MSA has closed 23 matters since the start of 2017, while 17 remained unresolved. Three of the matters closed during this quarter were addressed with a notice of specified penalty, totalling $7,500 in financial penalties.



10
8
6
4
2
0
BAL-004
BAL-005
COM-001
EOP-001
FAC-003
INT-009
PRC-001
PRC-023
VAR-002
VAR-501
Forbearance
NSP
Unresolved

Recommendations

Over the years the MSA has made many recommendations, mostly focused on the wholesale electricity market. In its Q1 2017 Report, the MSA began tracking recommendations and their outcomes. The table below is a summary of recommendations made or referenced in 2015, 2016 and 2017 quarterly reports, and will be maintained going forward.

Table 7: Current Status of MSA Recommendations

First Report	Subject	Recommendation	Comments/Outcome
2013 Q2	Natural Gas Generation Outage Reporting by the AESO	Public outage information used for generator outage coordination or forming future price views is inaccurate until close to real time. The MSA recommends disaggregating natural gas outages by simple cycle, combined cycle, and cogeneration in the outage reports. [Q1 2017]	The initial analysis was revisited in Q4/15, and subsequent discussions with the AESO informed the analysis and recommendation presented in the 2017 Q1 report.
2015 Q2	Import Enablement via Additional Operating Reserves	In real time AESO will activate standby contingency reserves if required and if available. However, on many occasions the standby reserves are generators that are already running and providing energy to the system. As they are activated from standby they withdraw from the energy market. Paying to withdraw from the energy market to enable imports also requiring payment does not seem like an efficient outcome. Therefore, given the current structure of Alberta's operating reserves market, the MSA does not recommend the use of active operating reserve (or standby activations) as a mechanism of enabling imports.	A further example outlining the MSA's concern over this practice was described in the 2017 Q1 report.
2015 Q2	Activation Prices of Standby Reserves	A pay as bid activation price for standby reserve appears to be inefficient, particularly in periods of price volatility. The MSA recommends setting the activation price for standby at that of the active reserves and standby sellers then compete based on the premium they require.	

First Report	Subject	Recommendation	Comments/Outcome
2016 Q2	Standby Regulating Reserve Volumes	The AESO rarely used all of the standby regulating reserves procured. The MSA recommended reducing the buy volume of standby regulating reserve as it appeared reductions in procurement would not increase conscription rates. [2016 Q2]	The AESO reduced the buy volume by 20 MWs in September 14, 2016. The MSA estimates the reduction in procurement costs is approximately $1m from the time the change to the end of Q1 2017. This in turn reduces the amount that needs to be charged to consumers through Rate DTS of the ISO tariff.
2016 Q4	LSSi contract structure	In 2016 $10 million was spent on availability payments for LSSi, but there were no armings. With the aim to change the payments structure such that LSSi payments were for actual services provided, the MSA recommends the AESO re-examine the three part pricing structure of LSSi contracts prior to the expiry in 2018.	
2017 Q1	Micro Gen Regulation	To avoid uncertainty of how the Micro-Generation Regulation is interpreted, the MSA believes that there exists an opportunity to clarify what “name plate” capacity means in relation to AC/DC ratings of solar generators. The MSA recommends the Alberta Utilities Commission create such clarity by incorporating the appropriate AC/DC language into either Rule 24 or the Micro-Generator Application Process & Guidelines.	Complete. AUC has issued a new Rule 24 which became effective July 4, 2017. In “Form A” of Rule 24, there is a requirement to state nameplate capacity in terms of A.C. capability.

A Retail Market Shares

Figure 28: Retail Natural Gas Market Shares, Residential Customers, March 2017

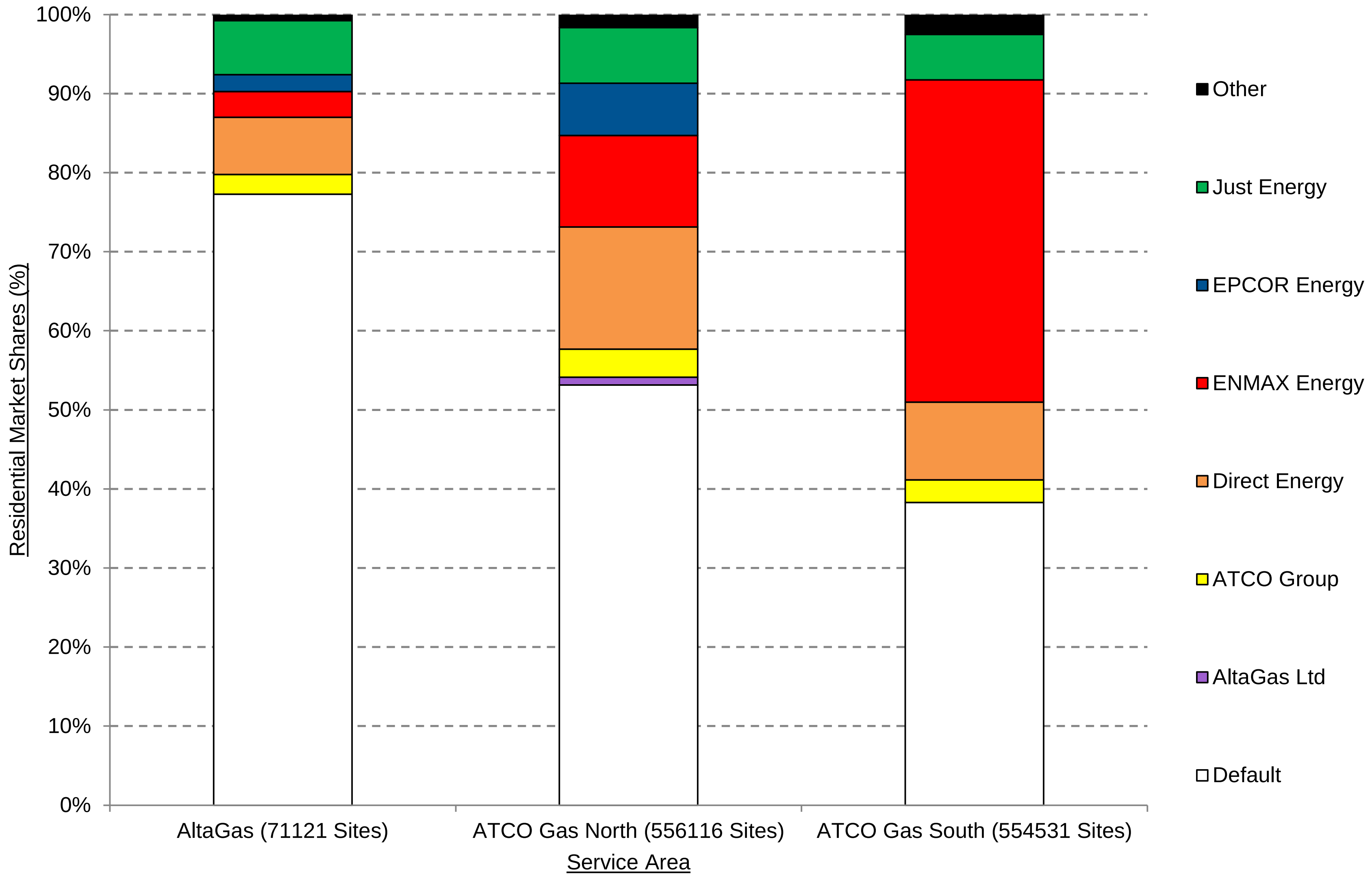


Figure 29: Retail Electricity Market Shares, Non-Residential Customers, All Service Areas, March 2017

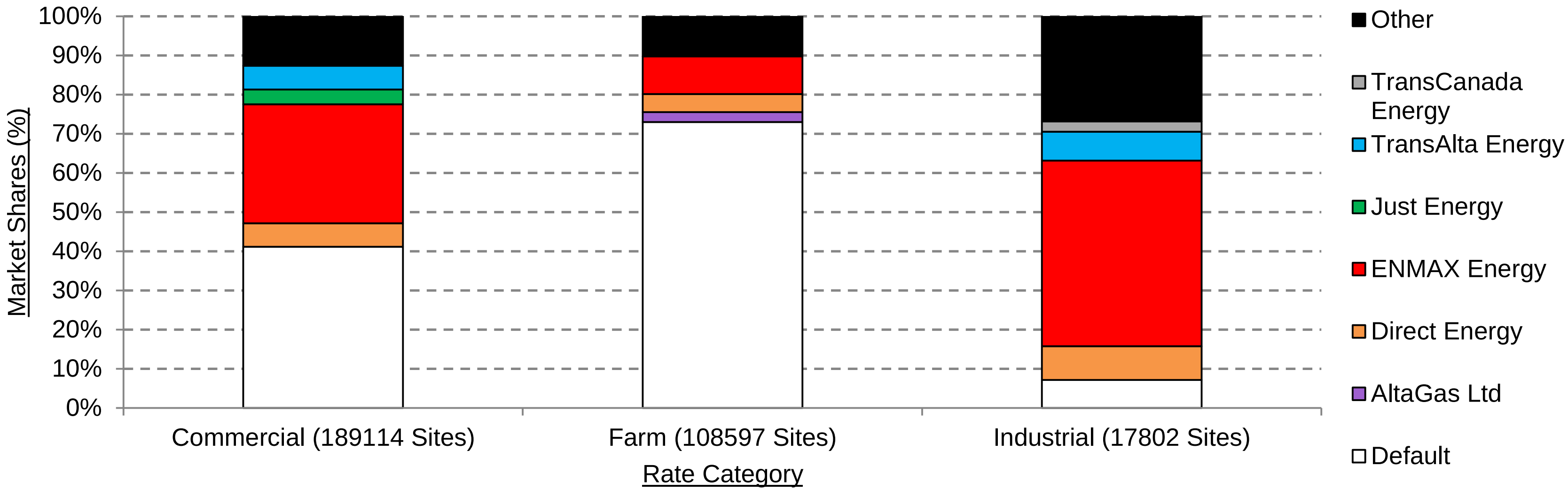


Figure 30: Retail Natural Gas Market Shares, Non-Residential Customers, All Service Areas, March 2017