Q4/2016 Quarterly Report

October – December 2016

February 16, 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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Annual Review

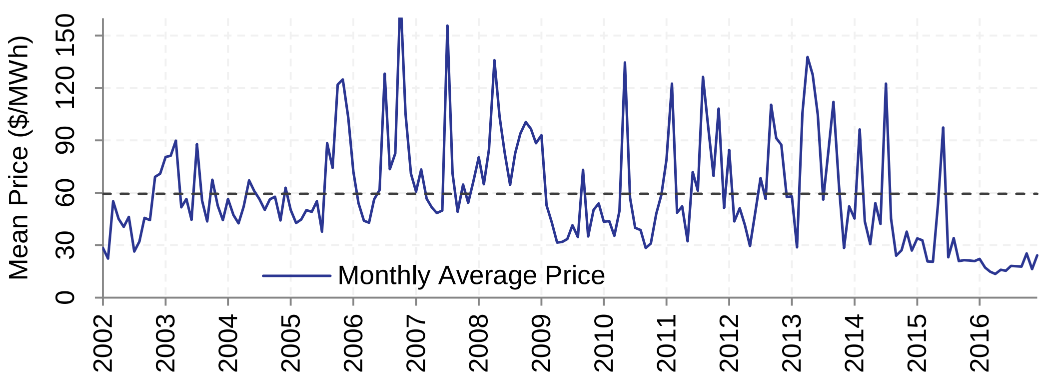
The MSA's Quarterly Reports typically focus only on market events that took place during the quarter in question. However, in recognition of the remarkably low pool prices and structural changes in 2016, the MSA has carried out a more comprehensive annual review. We use metrics and approaches developed in the 2012 State of the Market Report, and focus on examining the historically low pool prices, forward market activity after termination of the Power Purchase Arrangements (PPAs), and operating reserve (OR) markets. For data relating to Q4/2016, an appendix is provided in this report.

A compliance review is not included in this Quarterly Report as an annual compliance report will be published shortly.

Wholesale Market in 2016

The year 2016 set a historical low average pool price for electricity, as is clear from Figure 1. Pool price in 2016 averaged $18.28/MWh ($15.37/MWh extended off-peak, $19.73/MWh extended on-peak), falling over 45% compared to 2015, a year which was then the historical low since the year 2000 and the introduction of the PPAs. The average pool price in 2016 was almost 70% lower than the average from 2002 to 2016 ($59.33/MWh) and 2016 contains nine of the ten lowest priced months over this 15 year period.

Figure 1: Average Monthly Pool Price



A number of market conditions are contributors to these record low pool prices:

- Relatively high supply cushion compared to recent years;
- Offer control around PPA terminations affecting the offers of many coal-fired units;
- Lower offers because of lower natural gas prices; and
- Lower year-over-year demand.

Prior to 2016, brief periods of high pool prices would contribute significantly to high average prices. From 2002 to 2015, about 4.5% of hours had pool prices above $200/MWh. These hours increased the average pool price in this period by almost 50%. As seen in Figure 2, in previous years the relatively high prices occurred during on-peak hours, when electricity demand is greatest and there is the greatest likelihood of generation scarcity, while the relatively low prices occurred during off-peak hours. By contrast, in 2016 there was very little variation between on-peak and off-peak prices.

Figure 2: Average Annual Pool Price by Hour Ending

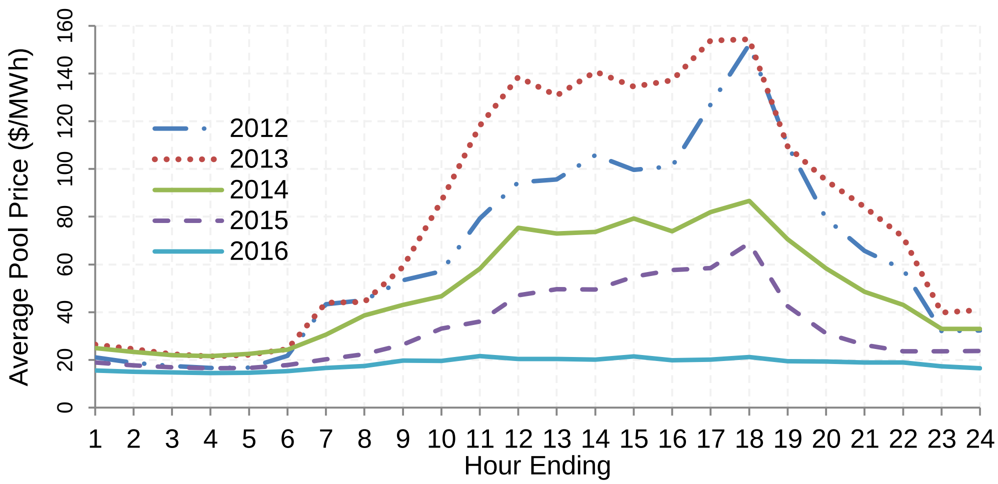


Table 1: Annual Summary

	2015	2016	*Change*
Pool Price ($/MWh)	$33.34	$18.28	*-45.2%*
Gas Price ($/GJ)	$2.56	$2.05	*-20.1%*
Alberta Internal Load (TWh)	80.3	79.6	*-0.9%*
Wind Generation (TWh)	4.1	4.5	*+8.0%*
Peak Load (MW)	11,229	11,458	*+2.0%*
Average Supply Cushion (MW)	2,167	2,269	*+4.7%*

Supply Cushion

As shown in Table 1, the supply cushion in 2016 was on average 4.7% higher than 2015. In comparison with prior years, both 2015 and 2016 were years with relatively high supply cushions (Figure 3), which all else equal is expected to result in relatively low pool prices. Pool prices in 2016, however, are notable because despite overall higher supply cushion in most hours, 2016 had more frequent hours with low supply cushions than 2015, where low supply cushion is considered to be, say, less than 1,000 MW (see Figure 4). While the MSA's supply cushion methodology considers only un-dispatched supply in the real time merit order, Figure 5 adjusts the supply cushion to include additional potential for imports and finds that while low supply cushion hours are still slightly more common in 2016, the years are very similar overall. Therefore, in addition to the historically low average pool price in 2016, it was lower than what has been observed in similar supply-demand conditions in previous years (also see Figure 6).

Figure 3: Supply Cushion Duration Curve by Year

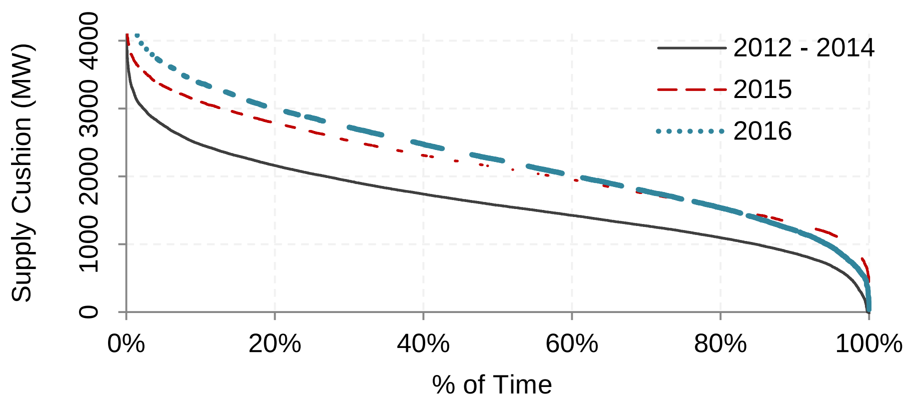


Figure 4: Supply Cushion Duration Curve by Year (Upper End)

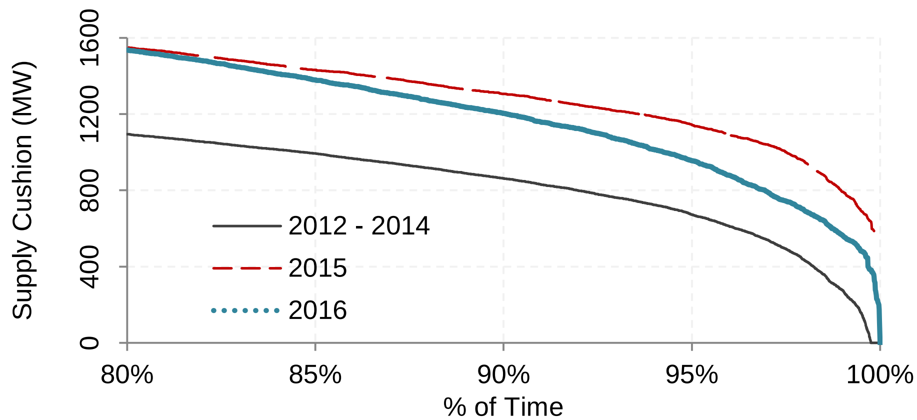
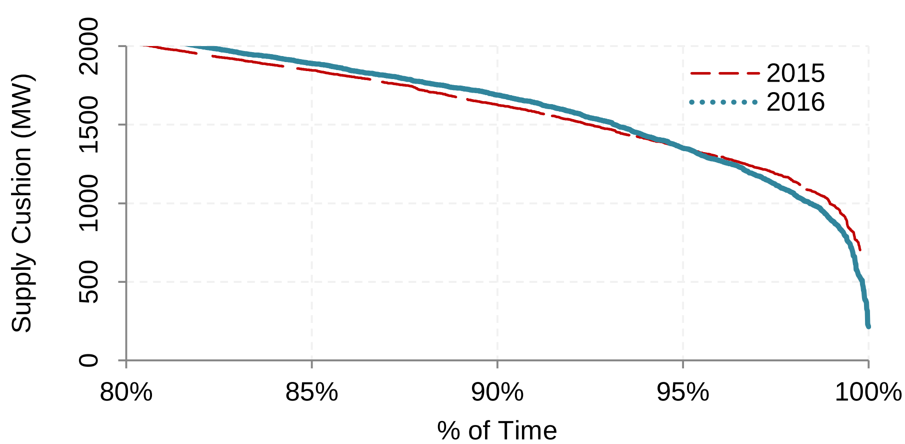
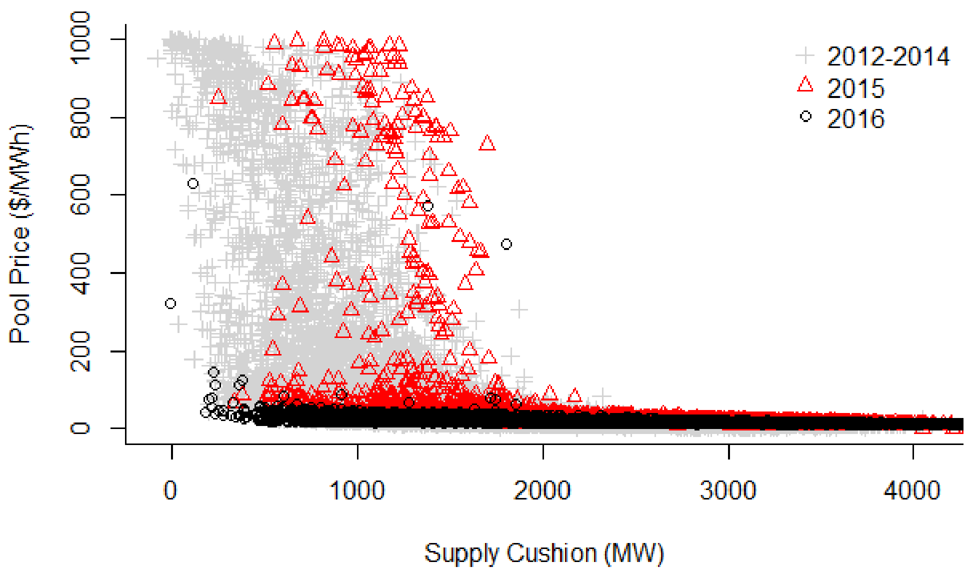


Figure 5: Supply Cushion Duration Curve by Year (Upper End, Adjusted for Import Availability)



As shown in Figure 6 and reported in the MSA's Q2/2015 Quarterly Report, a number of hours in 2015 were remarkable for having a high pool price given the prevailing supply cushion level. In each case examined by the MSA, the pool price was driven by relatively large amounts of economic withholding. Given the supply cushion in 2016 was broadly similar to conditions in 2015, a 45% decline in the average pool price can be linked, in part, to changes in offer behaviour. Changes in offer behaviour could be from both lower gas prices, and the termination of the remaining thermal PPAs.[1]

Figure 6: Supply Cushion and Pool Price Relationship



Specified Gas Emitters Regulation

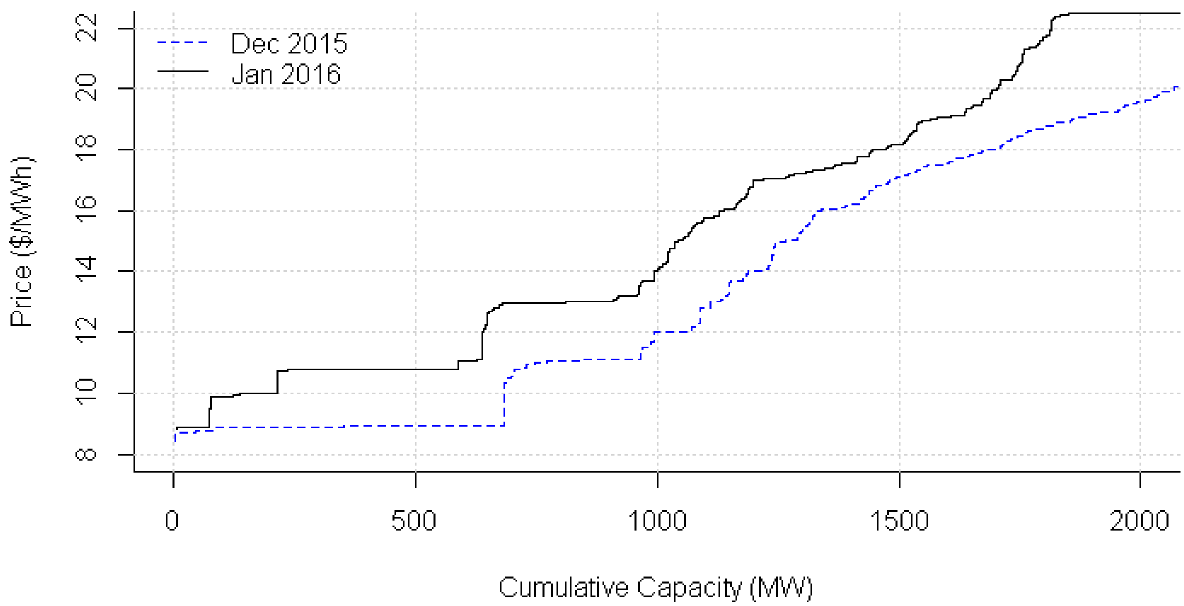
On January 1, 2016, certain changes to the *Specified Gas Emitters Regulation* (SGER) came into effect. The changes affected the marginal cost of electricity generation facilities that are subject to the SGER, which in turn may affect offers, specifically offer prices, made to Alberta's power pool. The MSA has sought to understand whether offer behaviour changed from before to after the SGER changes.

Prior to January 1, 2016, the SGER required large emitters to make payments of $15/tCO2e for any emissions above a facility-specific emissions intensity target, which was set at 12% below the established baseline for the respective facility.[2] Effective January 1, 2016, the SGER changes increased the targeted intensity reduction to 15% below the baseline and increased payment rate to $20/tCO2e. It was this increase in the SGER rates that was identified as the change-in-law relevant for termination of the PPAs. To examine the potential effect of the change in the SGER rates, Figure 7 shows the cumulative non-zero priced coal-fired generation offered during the on-peak hours below $23/MWh for December 2015 (pre-SGER change) to January 2016 (post-SGER change). Offers in this price region are likely to be more reflective of a generator's marginal cost. Inspection of the figure indicates that low coal-fired offers increased

[1] Other than the PPA for Genesee 1 and 2 which are held by the Balancing Pool.
[2] Payments could also be avoided by actual reduction of emission intensity, purchase of other elig ble offsets, or use of emissions performance credits. Also, targets differ by the age of the facility. 12% was based on a facility in its ninth year of operation or older.

by an average of $2/MWh, mostly in a range of $1.50/MWh to $2.40/MWh. This is comparable to the expected impact of SGER on coal generators.[3]

Figure 7: Aggregate[4] Non-Zero On-Peak Coal Offers, Pre and Post SGER Change



It is not the case that the SGER changes would necessarily increase the price of electricity in every hour of the year. Clearly, prices in 2016 were significantly lower than 2015 despite the increase in the SGER rate. The extent to which the price consumers pay is impacted depends on the frequency with which the market is clearing at a cost-based offer that was increased by the SGER. In the past, off-peak pool prices have more often been at marginal cost than on-peak pool prices. Historically, with lower supply cushions, on-peak pool prices have more often been affected by economic withholding.

Offer Control at PPA Units

In late 2015 and the first half of 2016, the Balancing Pool was given notice of termination by the respective PPA Buyers for the extant thermal PPAs. The Buyers provided notice based on change-in-law provisions contained within the PPAs and cited the changes to the SGER as the reason for termination. In the same period notices of termination were served in relation to two 100 MW strip sales of the Genesee PPA.

The PPA terminations were announced as follows, ultimately leaving 4,131 MW of offer control in dispute (including the 200 MW strip sales) for all or part of the year:

[3] Specifically, a hypothetical coal-fired generator in its ninth year of operation (or older) and emitting 1 tCO2e per MWh (with a baseline of the same amount) would pay $1.80/MWh [(1 tCO2e/MWh * 12%) * $15/tCO2e] under the 2015 levels, and $3/MWh [(1 tCO2e/MWh * 15%) * $20/tCO2e] under the 2016 rules; an increase of $1.20/MWh.
[4] Aggregated merit orders were constructed by combining all on-peak merit orders and dividing availability by the number of on-peak hours in the time period. The graph is cropped to show detail in the lower portion of the curve.

- December 11, 2015: notice provided to terminate Battle River 5 PPA as of January 1, 2016.[5]
- March 7, 2016: notice provided to terminate Sheerness, and Sundance A & B PPAs[6]
- March 24, 2016: notice provided to terminate Sundance C PPA[7]
- May 6, 2016: notice provided to terminate Keephills PPA[8]

Subsequent to receiving a notice of termination, the Balancing Pool is required under Section 2(1)(g) and (h) of the *Balancing Pool Regulation* to conduct an appropriate investigation. In the event of termination, the Balancing Pool has a number of options available, including returning the unit to the original owner subject to some terms and conditions. On January 27, 2016 the Balancing Pool sent a letter confirming the buyers' right to terminate the Battle River 5 PPA.[9] On July 25, 2016, the terminations were contested by the Government of Alberta.[10] In the first quarter of 2016, as a result of a negotiated settlement, the Balancing Pool received a one-time payment related to the termination of one of the 100 MW strip contracts.[11]

The Balancing Pool was able to assume offer control of Battle River 5 as of June 28, 2016[12] and the Genesee strips as of July 7, 2016.[13] For the remainder of the year the offer control of the other terminated PPAs remained with the PPA Buyers. As of January 10, 2017 following a number of settlement agreements the Balancing Pool assumed offer control of the Sheerness and Sundance PPAs.[14]

During the course of the dispute over the termination of the PPAs, the PPA capacity was offered at relatively low prices whereas there were significantly more offers at high prices in 2015 (see Figure 8). While uprates may have been offered at high prices, the MSA did not observe any instances of economic withholding of these generators by the PPA Buyers after the announced termination dates.

Figure 9 shows the PPA units were typically offered in a range from $10 to $25/MWh. This change in offer strategy would have the overall effect of decreasing pool price, although as noted in a later section, the PPA coal units ceased participation in OR markets, which may have had an adverse effect. In 2016, System Marginal Price was set by one of the terminated PPA units 66% of the time, compared to about 55% of the time in 2015.

[5] Balancing Pool News Release, February 24, 2016.
[6] Balancing Pool News Release, March 21, 2016.
[7] Capital Power News Release, March 24, 2016.
[8] ENMAX News Release, May 6, 2016.
[9] Balancing Pool News Release, February 24, 2016.
[10] Government of Alberta Press Release, July 25, 2016.
[11] Balancing Pool Q1 2016 Condensed Interim Financial Statements and Review, May 2016.
[12] Alberta Utilities Commission Decision 21406-D01-2016, June 28, 2016.
[13] Alberta Utilities Commission Decision 21375-D02-2016, July 8, 2016.
[14] Balancing Pool News Release, January 13, 2016 [sic].

Figure 8: Aggregate On-Peak Offers from PPA Units, 2015 versus 2016

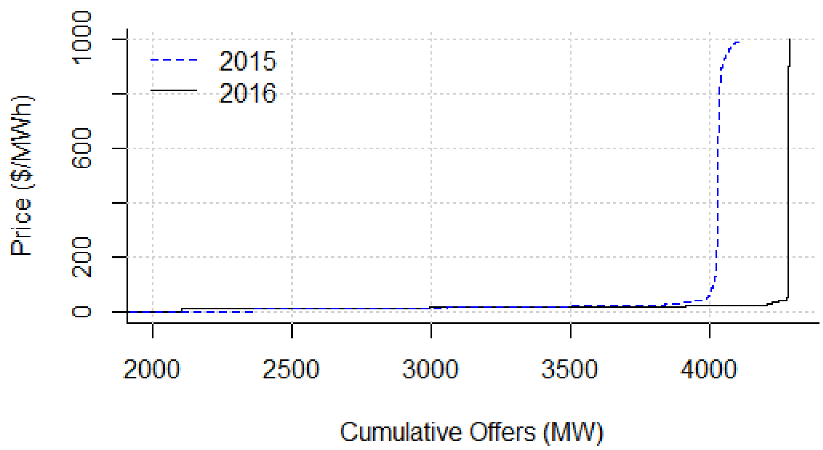
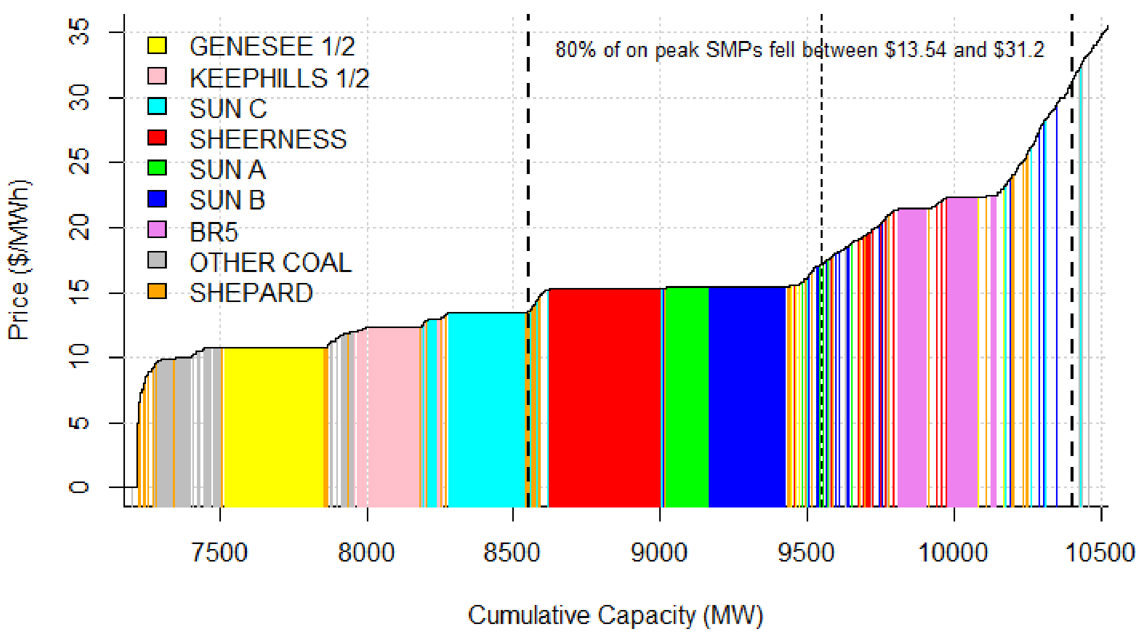


Figure 9: Aggregate 2016 On-Peak Merit Order (PPA Unit Offers)



Generation Sources

The change in offer behaviour could have had the impact of increasing total coal-fired generation. However, despite the change in offer behaviour (and an increase in overall availability of the coal fleet), Figure 10 shows that total coal-fired generation and PPA unit coal generation both declined compared to 2015.

Utilization continues on the downward trend shown in Figure 11. Coal-fired generators generated at about 80% of availability capability in 2016, down from 84% in the previous year.

One reason for this decline is the significant decrease in natural gas prices at the beginning of 2016, as shown in Figure 12. With the EGC1 (Shepard) plant's availability over 31% higher than in 2015 and output increasing by 35%. Low natural gas prices are likely to have resulted in gas generators offering below coal-fired generators. For example, Figure 9 shows some EGC1 offers under $10/MWh. Only the coal units with the lowest marginal costs and offers (Keephills 1 to 3 and Genesee 1 to 3) had utilization factors above 90%.

Another contributing factor to the decline of coal-fired generation is the frequent idling of Battle River 3 & 4. In 2015, Battle River 3 only generated approximately 12% of its available capability, falling to 2% in 2016. Battle River 4, on the other hand, fell from 69% in 2015 to 25% in 2016.

Figure 10: Total Annual Coal Generation (TWh)

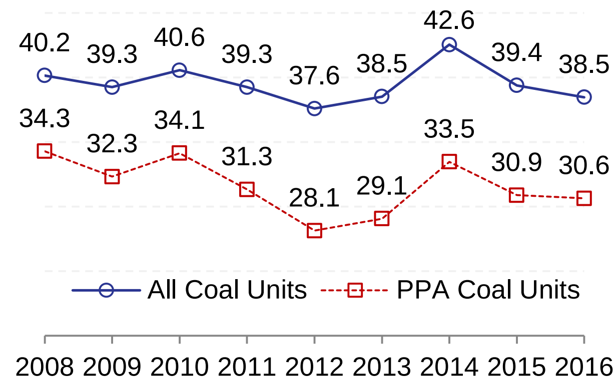


Figure 11: Total Annual Coal Utilization (Generation / Availability)

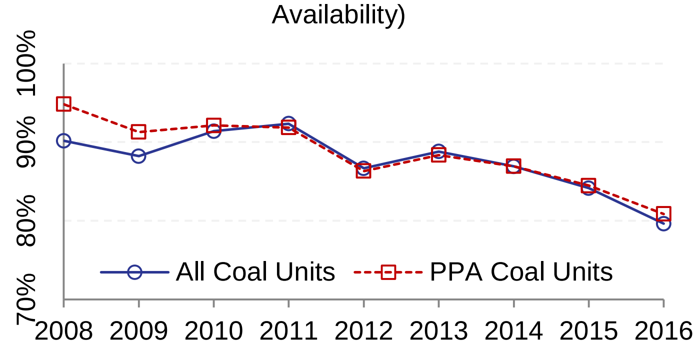


Figure 12: AECO-C Daily Gas Price ($/GJ)

Lower Demand Year-over-Year

Total Alberta Internal Load (AIL) declined about 1% in 2016 to 79.6 TWh (Figure 13), which included the reduction in load around the Fort McMurray fire starting in May of 2016.

Despite the lower total annual load, Q4/2016 saw average Alberta Internal Load (AIL) increase 2.1% year-over-year. This demand growth follows four consecutive quarters of declining year-over-year demand, as shown in Figure 14.

Figure 13: Total Alberta Internal Load (AIL) (TWh)

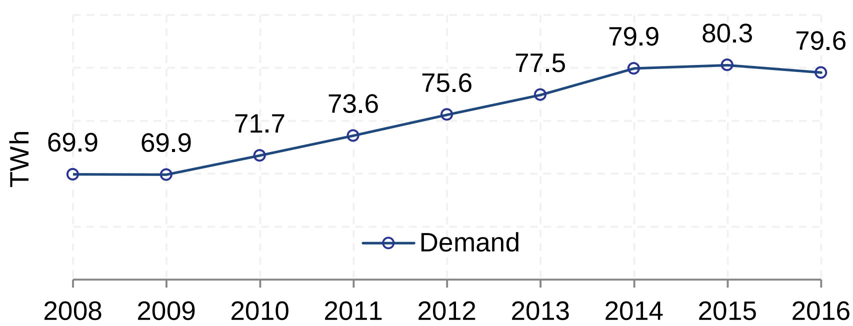
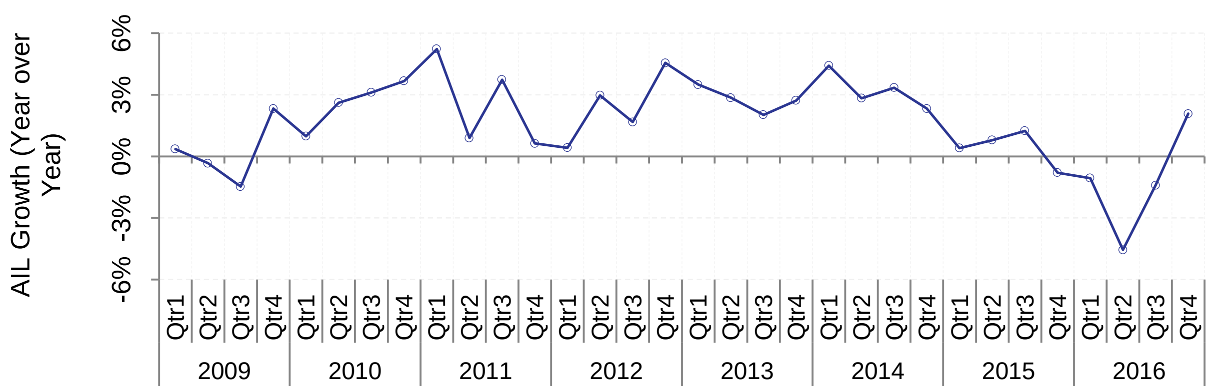


Figure 14: Growth in Alberta Internal Load (% Year-over-Year)



Load Forecasting

In May, the AESO 2016 Long-term Outlook was published, wherein the Reference Case prediction of 2020 load was adjusted down to only 18% above 2016 levels.[15] This is in contrast to the 2014 Long-term Outlook Main Outlook Scenario,[16] which forecasts 2020 load to be 31% higher than 2016 load. Total load in Q4/2016 was just over 21 TWh, approximately 3% and 5% lower than the 2016 and 2014 forecasts, respectively. Figure 15 shows this divergence, as well as the decrease in year-over-year load experienced in the four quarters preceding Q4/2016.

[15] AESO 2016 Long-term Outlook, Reference Case Scenario, May 4, 2016.
[16] AESO 2014 Long-term Outlook, Main Outlook Scenario, May 30, 2014.

The AESO also forecasts peak load in each Long-term Outlook. The actual 2016 peak load of 11,458 MW was 4% and 2% lower than the Main Outlook and Reference Case forecasts made in 2014 and 2016, respectively.[17]

Figure 15: Alberta Internal Load and AESO Main Outlook (2014) and Reference Case (2016) monthly demand forecasts (GWh)[18]

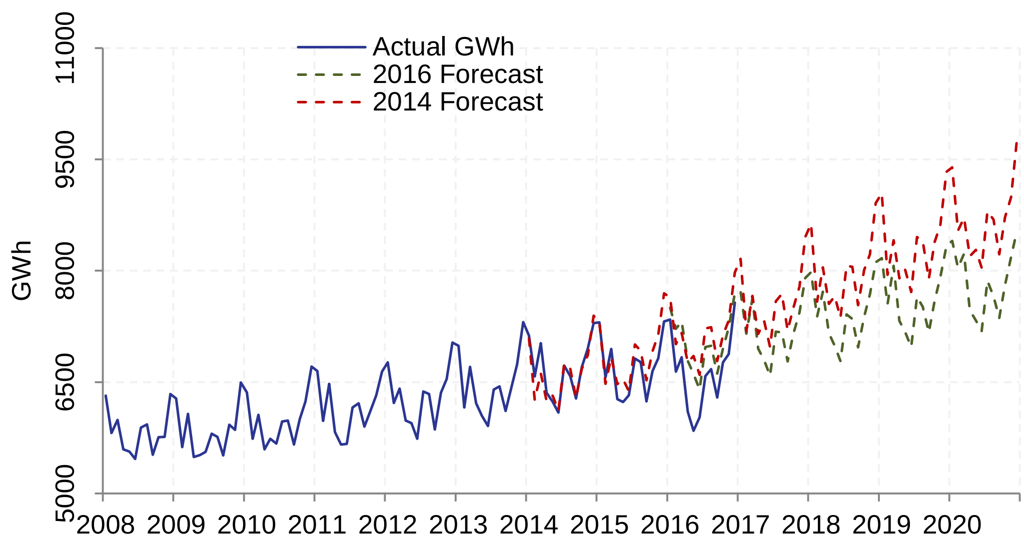
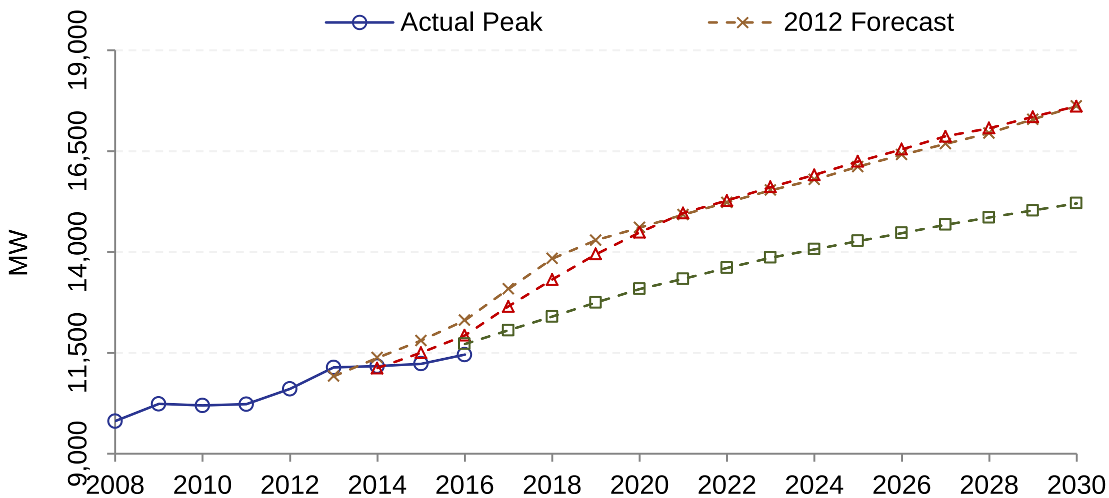


Figure 16 illustrates that the AESO has more recently adjusted its long-term peak demand forecasts to markedly lower levels. At 13,336 MW, the 2021 peak load forecast made in 2016 is 11% lower than the 2021 forecasts made in both 2012 and 2014. This amounts to a reduction in forecasted volume of 1,590 and 1,633 MW between the 2012 and 2014 forecasts (respectively) and the 2016 forecast.

[17] 2014 forecast data is from the Main Outlook scenario, while 2016 data forecast is from the Reference Case scenario.
[18] Forecast data available in the 2014 Long-term Outlook data file (May 30, 2014) and 2016 Long-term Outlook data file (May 4, 2016). 2014 forecast data is from the Main Outlook scenario, while 2016 data forecast is from the Reference Case scenario.

Figure 16: Annual Peak Alberta Internal Load (MW)[19]



December 2016 Peak Demand Event

Alberta set a new record peak demand in Hour Ending (HE) 18 on December 16, 2016. The AIL was 11,458 MW in that hour at a settlement price of $32.75/MWh. This breaks the previous record set in HE 18 on January 5, 2015, when demand reached 11,229 MW at a settlement price of $780.86/MWh. As reported in Table 3, seasonal demand over the last nine years peaked in either December or January (the winter season) during HE 18, when it is dark in Alberta.

The MSA examined the components of the December 2016 peak demand, and compared it to the peak in 2015. Given the relatively low price in 2016, part of the difference could have been the level of participation of price responsive demand, i.e., with a low prevailing price at the 2016 peak, price responsive consumers may have chosen to consume. However, analysis showed this not to be the case, consumption by price responsive consumers in the 2016 and 2015 peaks was similar, as explained below.

Table 2: Winter Peak[20] Demand Events, 2008 - Q4/2016

	Date of Winter Peak	**Hour Ending**	**Peak Demand (MW)**	**Settlement Price**
Winter 2008/09	December 15, 2008	18	9,806	$699.00
Winter 2009/10	December 14, 2009	18	10,236	$96.13
Winter 2010/11	January 12, 2011	18	10,226	$165.12

[19] 2012 Forecast data retrieved from the AESO 2012 Long-term Outlook. 2014 forecast data is from the Main Outlook scenario, while 2016 data forecast is from the Reference Case scenario.
[20] "Winter" is defined as the months December through February of the following year.

Winter 2011/12	January 16, 2012	18	10,609	$716.40
Winter 2012/13	December 10, 2012	18	10,599	$34.50
Winter 2013/14	December 2, 2013	18	11,139	$235.45
Winter 2014/15	January 5, 2015	18	11,229	$780.86
Winter 2015/16	December 22, 2015	18	10,982	$33.16
Winter 2016/17	December 16, 2016	18	11,458	$32.75

As shown in Figure 17, for a given temperature, demand is typically higher on average in December than in January or February. This may be due to additional demand from Christmas lighting or the earlier activation of street lighting (December having the fewest number of daylight hours of the year). Figure 18 also shows the average temperatures in Calgary and Edmonton were lower on December 16, 2016 than January 5, 2015.

One notable feature about the latest peak is that, despite the absence of a price spike in the December 2016 peak demand hour, price responsive loads scaled back a significant amount (Figure 19). The reduction was similar to that in the January 2015 peak demand event when pool price was $780.86/MWh. While the AESO's supply adequacy report did not indicate any shortfall of generation, the published demand forecasts were forecasting record demand of over 11,400 MW. Consumers may choose to avoid peak hours due to the chance of a price spike, or as a way of managing transmission costs. In particular, demand transmission service (DTS) charges for a site are allocated based on the site's fraction of total demand during system peak conditions.

The MSA also looked at differences in AIL and provincial demand that is not served by behind-the-fence generation (referred to as system demand or Alberta Interconnected Electric System (AIES) demand) during the two peaks (Figure 20) and found that while system demand was similar during the two days, AIL was markedly higher during the 2016 peak day, due to approximately 350 additional MW of demand served by behind-the-fence generation during the 2016 peak.

Figure 17: Average Temperature and Weekly Peak Demand Relative to Annual Winter Average, Winter 1999 to Winter 2016

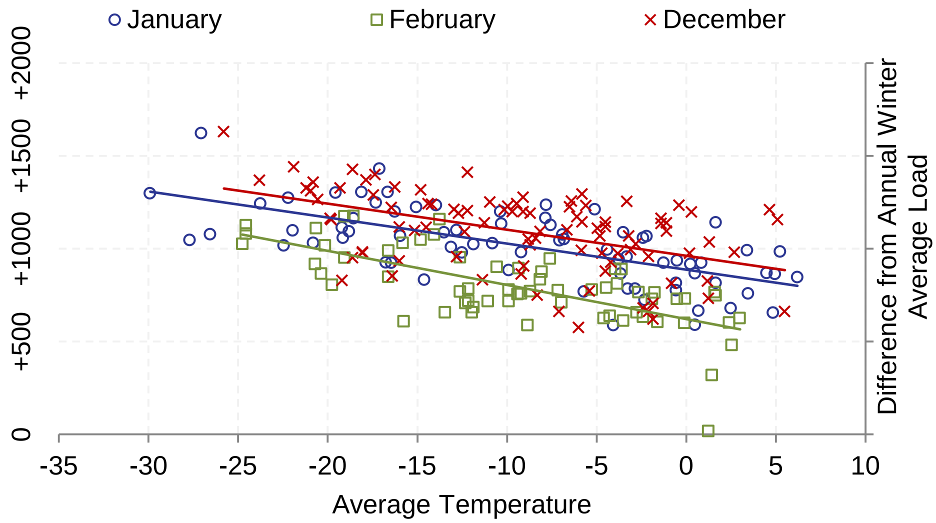


Figure 18: Alberta Temperatures on January 5, 2015 and December 16, 2016

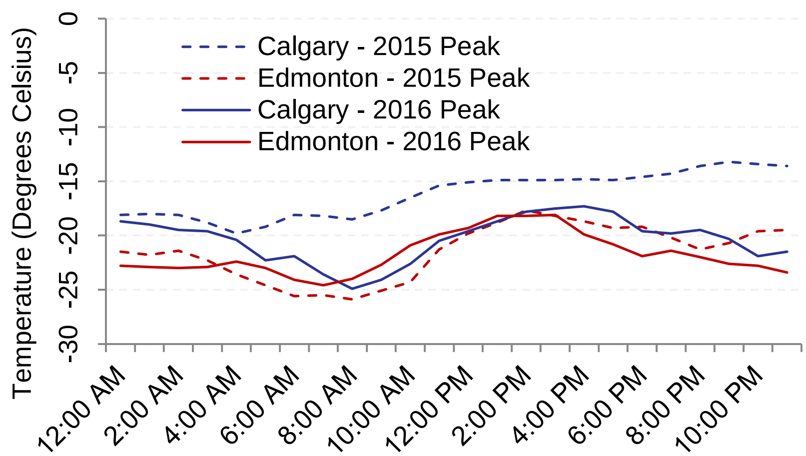


Figure 19: Price Responsive Demand[21] During January 2015 and December 2016 Peak Demand Events

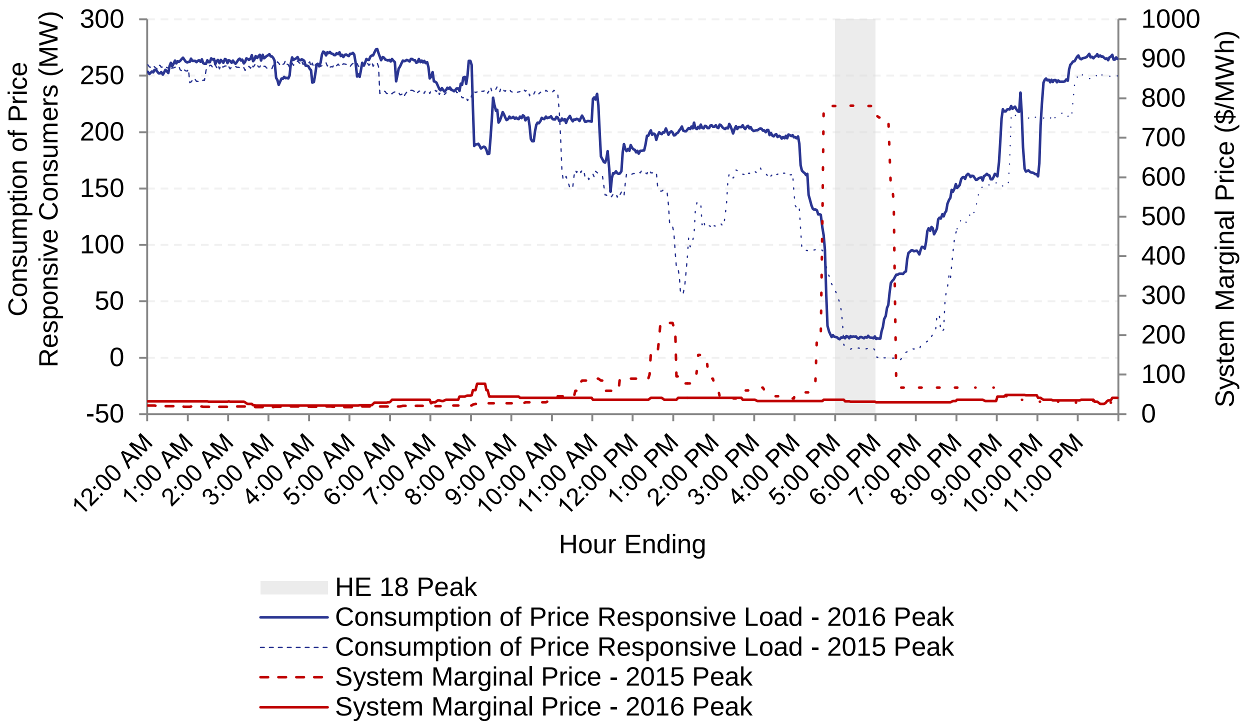
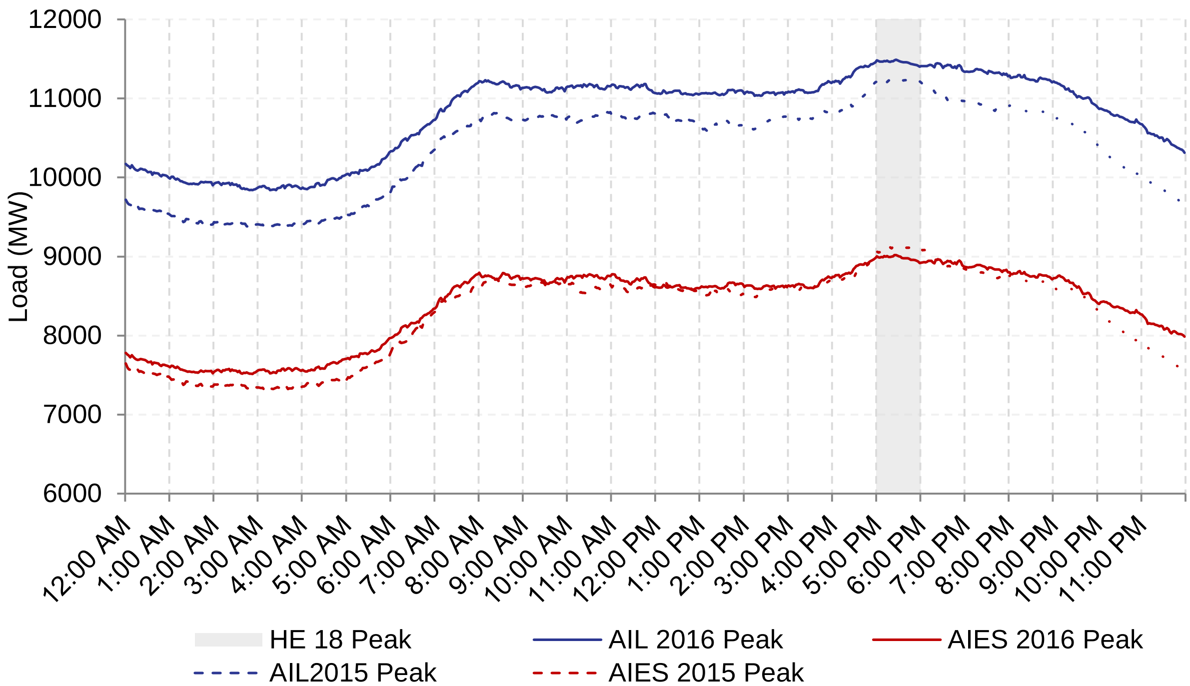


Figure 20: Alberta Internal Load (AIL) and System Load (AIES) on 2015 and 2016 Peak Demand Days



[21] This is an aggregate measure constructed by the MSA that includes a set of large loads that have historically reduced consumption when prices were high, and is not necessarily inclusive of all consumers that may respond to price.

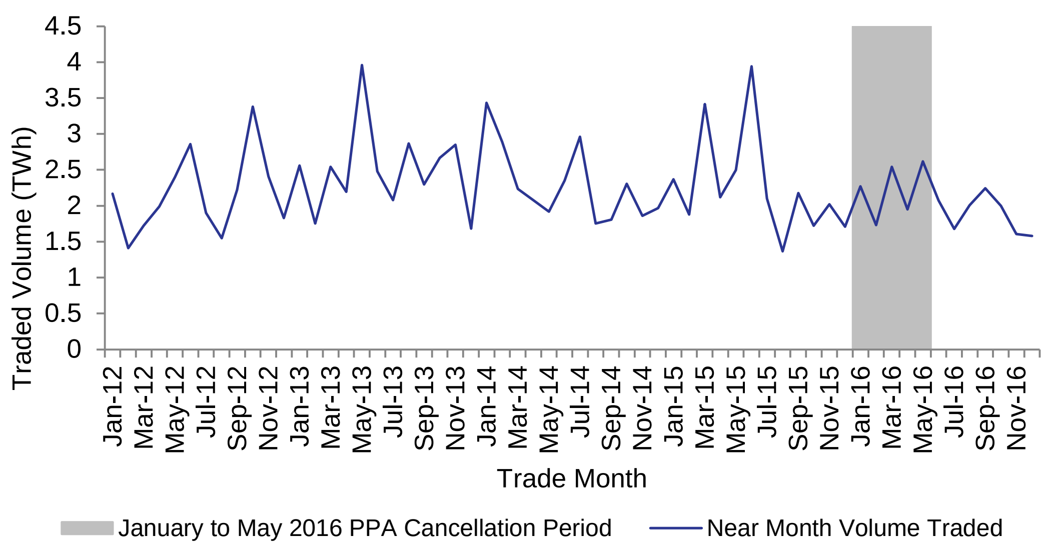
Forward Market

In the MSA Q1/2016 Quarterly Report, the MSA commented on the level of monthly "near month" traded forward volumes as the PPAs began to be terminated. The possibility that PPA buyers could stop participating, or at least reduce their participation, in the "near month" forward markets was of concern to the MSA, as a reduction in traded volumes could adversely impact the forward market. Also, the Regulated Rate Option (RRO) could be impacted if lower market liquidity were to impact forward market prices.

Figure 21 is an updated version of the graph presented in the aforementioned report, showing the volume of monthly contracts traded in a month for delivery within the subsequent 120 days.[22] For example, in June 2015, almost 4 TWh of monthly contracts for delivery between July and October were traded. Liquidity of these "near month" contracts is critical to the functioning of the RRO, under which hedges are procured up to 120-days prior to the delivery month.

Since the last of the PPA notices of termination in May 2016, subsequent months have seen generally steady liquidity in "near month" contracts with traded volumes in Q4/2016 comparable to those in observed historically. Despite the possibility that generators for which PPAs were terminated were no longer being sold forward, there has not been a significant drop in near month liquidity.

Figure 21: Volume of "Near Month" Monthly Contracts, by Trade Month



RRO Volumes

RRO purchases comprised 11.8% of all contract volumes traded on the forward market in 2016. In 2016, 25.2% of all traded monthly extended-peak and flat contract volumes for 2016 delivery were purchased for the RRO (Figure 22). Notably, the RRO share of purchased contract

[22] MSA Q1/2016 Quarterly Report, Figure 15, p. 10.

volumes was lower for later delivery months in 2016; this was primarily due to increased forward market liquidity for products delivered later in the year (Figure 23).

Figure 22: RRO Share of Traded Monthly Flat and Peak Contracts, by Delivery Month

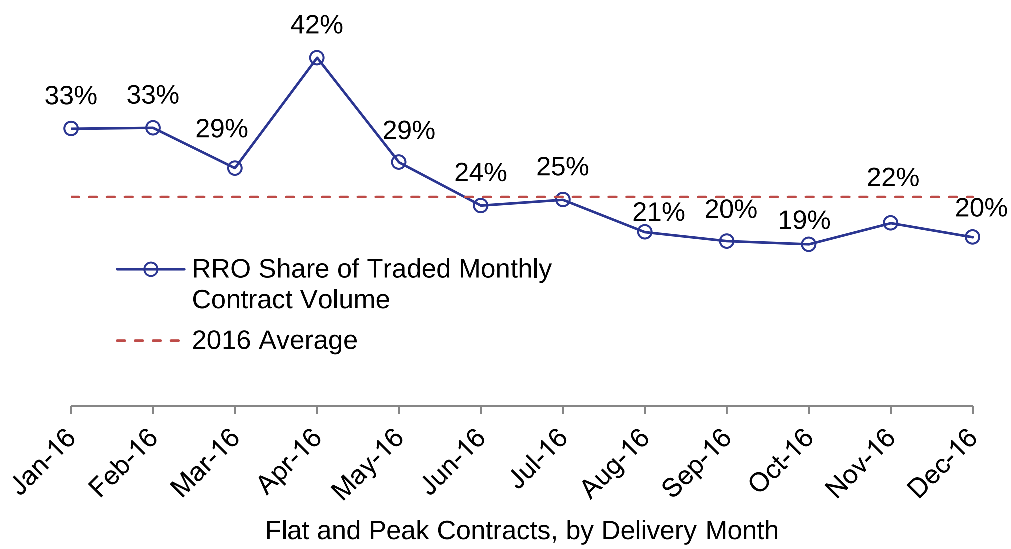
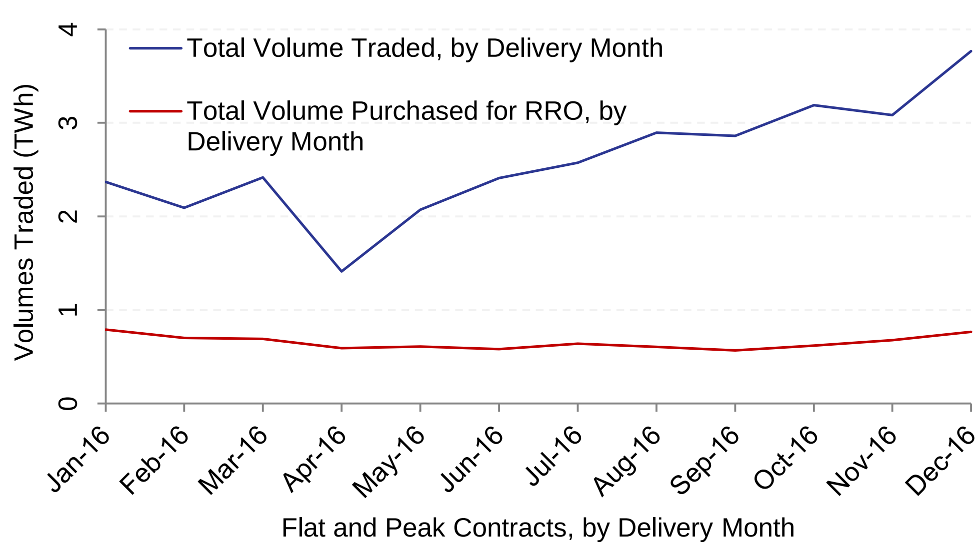
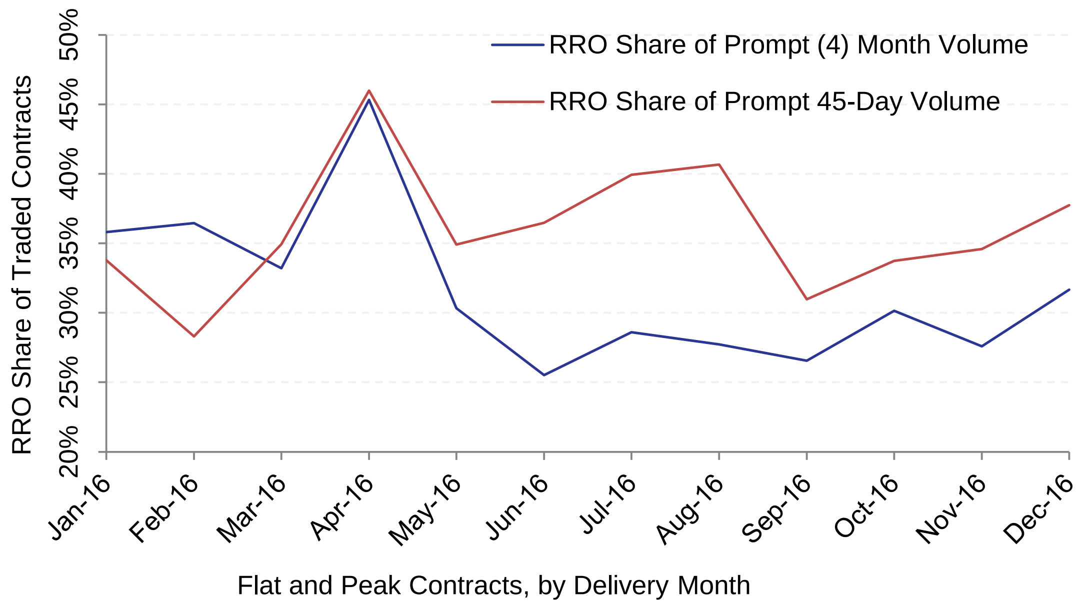


Figure 23: Volume of Monthly Flat and Peak Products Traded, by Delivery Month



RRO purchases comprised 31% of 2016 monthly flat and peak contract volumes traded within four months of their delivery month (Figure 24). This four month period corresponds to the 120-day procurement period for EPCOR’s RRO, the longest of any of the RRO providers. Similarly, RRO monthly contract purchases made within 45 days of the delivery month made up a larger 35.6% share of all traded volumes in the same period.

Figure 24: RRO Share of Contract Volume, by Delivery Month



When measured as total traded volume, forward market liquidity decreased slightly in 2016, while still above historical averages. Notably, monthly and yearly contracts were traded less frequently in 2016, while quarterly and daily contracts were traded more.

Table 3: Trade Volumes by Contract Term from 2008 to 2016 (TWh)

	Daily	Monthly	Quarterly	Yearly	Other	Total
2008	0.35	24.42	12.80	10.53	0.96	49.05
2009	0.41	21.27	15.40	21.23	1.02	59.34
2010	0.33	31.88	9.13	6.57	1.45	49.37
2011	0.20	24.64	4.08	11.62	1.66	42.20
2012	0.43	29.35	5.13	12.88	1.00	48.79
2013	0.19	35.05	5.92	11.04	1.33	53.52
2014	0.14	31.69	7.19	15.81	2.48	57.31
2015	0.42	32.54	3.46	31.03	1.74	69.20
2016	0.57	29.85	5.05	25.20	4.81	65.47

The trading multiple is an alternate measure of liquidity that measures the amount of traded volume given the underlying physical demand. Figure 25 illustrates that the trading multiple has changed little since 2015, with demand outpacing trade volumes in most months. Historical trading multiples shown in Table 4 suggest that the annual trading multiple has been increasing since 2011, although more recently this trend has been largely driven by large volumes traded in relatively few months. As previously reported by the MSA, trading multiples less than one are low relative to those in other markets.[23]

Figure 25: Total Trade Volume and Underlying Demand (TWh Monthly)

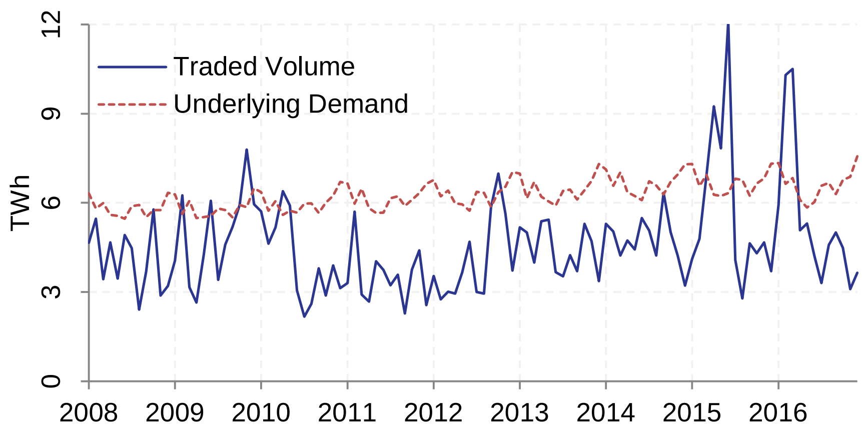


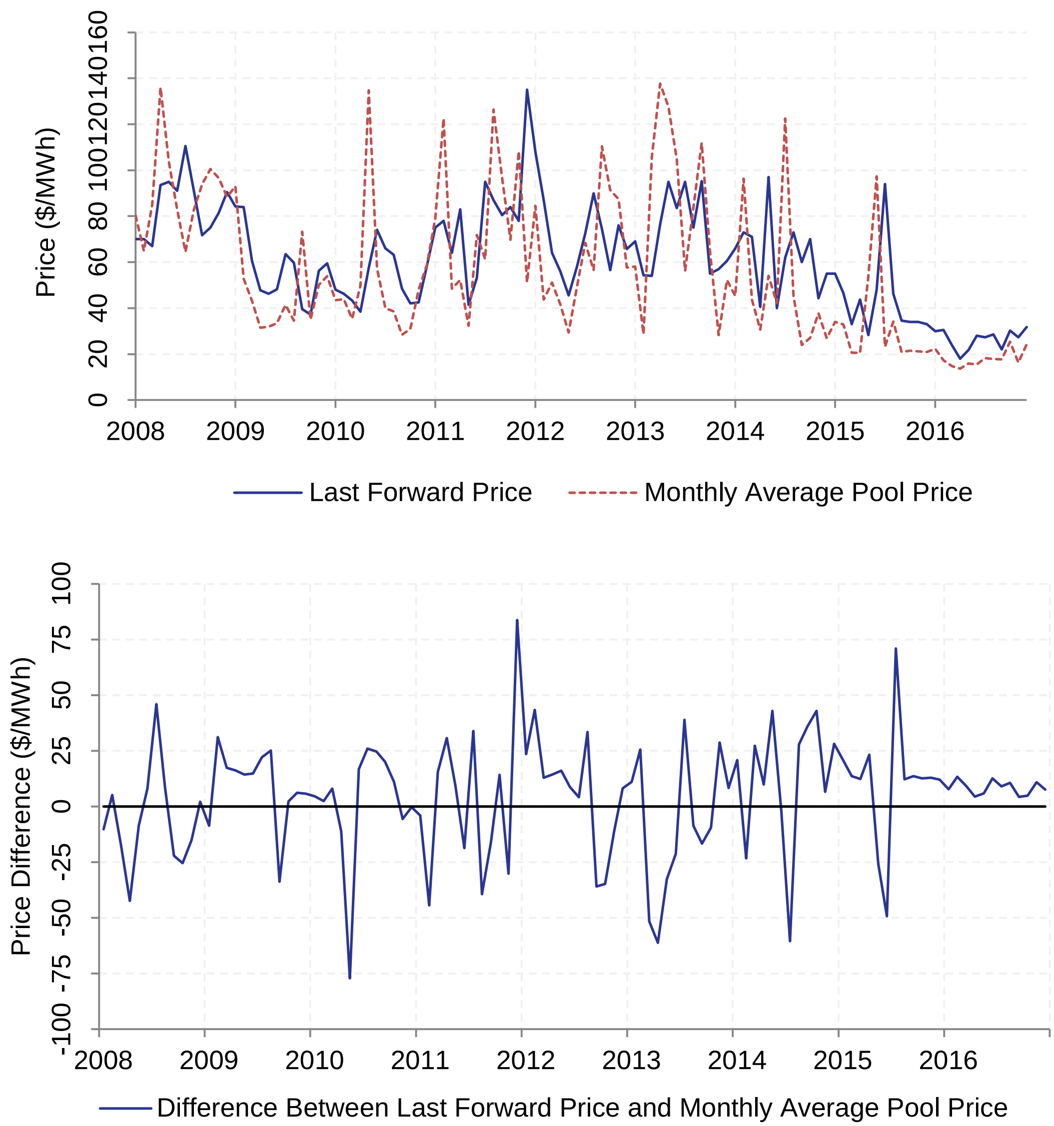
Table 4: Annual Trading Multiples, 2008 to 2016

Year	Trade Volume (TWh)	Underlying Demand (TWh)	Annual Trading Multiple
2008	49.0	69.9	0.70
2009	59.3	69.9	0.85
2010	49.4	71.7	0.69
2011	42.2	73.6	0.57
2012	48.8	75.6	0.65
2013	53.5	77.5	0.69
2014	57.3	79.9	0.72
2015	69.2	80.3	0.86
2016	65.5	79.6	0.82

Figure 26 depicts the relationship between the last forward prices for a given month, and the average pool price for that month. However, forward prices still remain above pool prices in most months.

[23] State of the Market Report 2012, 2.4.2.1, PDF p. 39.

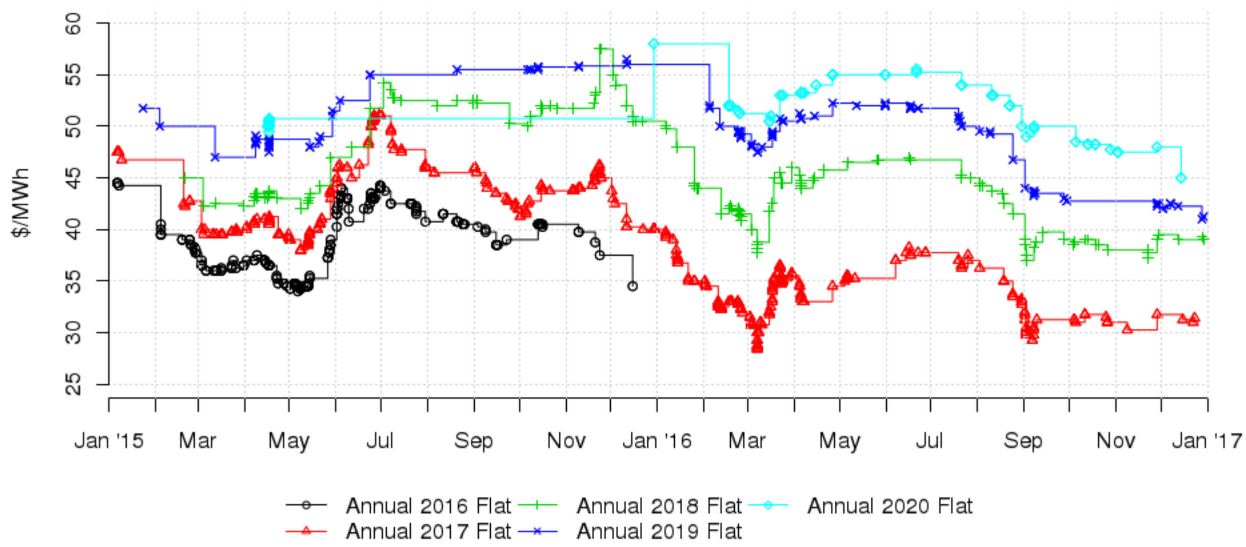
Figure 26: Forward and Spot Market Prices



Annual Forward Price Movements

In March 2016, the price of most annual contracts increased. By Q4/2016, they lost most of the price gains with 2019 and 2020 contracts falling even further below prices seen earlier in 2016.

Figure 27: Annual Flat Forward Contract Trade Prices by Date



Operating Reserves

Low pool prices during 2016 translated into lower prices and costs for most operating reserve (OR) products for the year. However, considering that historically low net revenue was available for providing energy in 2016, providing OR yielded relatively high returns. In particular, active regulating reserve (RR) cost $20.90/MWh on average, more than the average pool price in the year, and standby RR costs increased 70% (accounting for about 12% of total reserve costs).

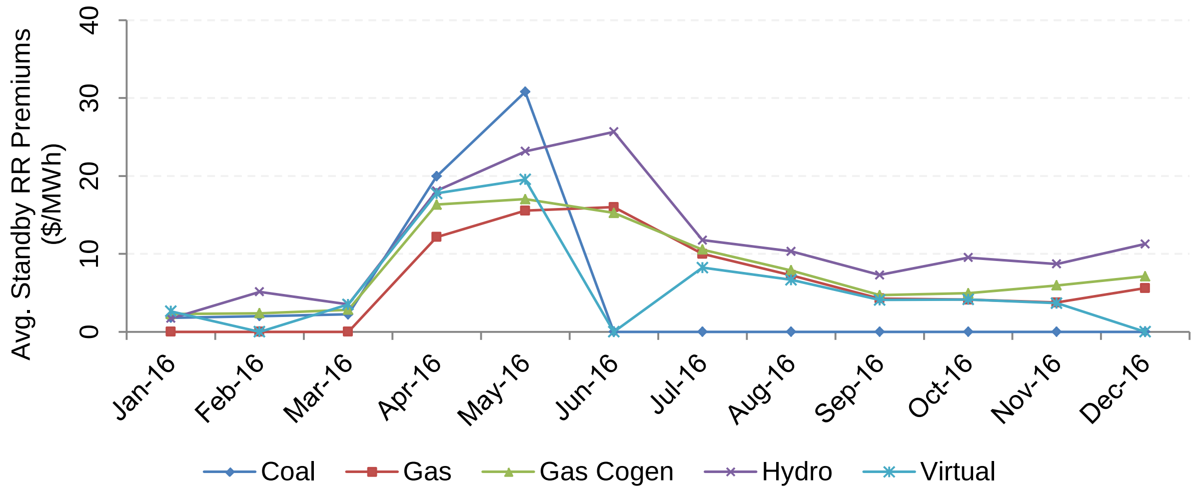
For 2016, total annual OR costs were approximately $66.7 million (Table 5), down 52% from 2015. As discussed, this was primarily due to lower than average pool prices during the year. The amount of active reserves procured has remained relatively stable over time, except as noted in the Q1/2015 Quarterly Report, when procured active reserves declined markedly from 2014 to 2015. This was because of the BAL-002-WECC change, effective October 1, 2014.

The annual cost of standby (including procurement and activation costs) has been trending down over the past three years. With the exception of procured standby for RR, the cost of most OR products fell significantly from 2015. As noted, the year-over-year total cost of procuring standby RR increased by 70%, with the average cost increasing from $5.25/MWh to $9.49/MWh. This increase was at least partially driven by higher premiums paid during Q2/2016 (see Figure 28).

Table 5: Operating Reserve Statistics (2012-2016)

Total Cost ($ Millions)					
	2012	**2013**	**2014**	**2015**	**2016**
Active Procured	**295.7**	**340.8**	**167.8**	**105.2**	**52.6**
RR	70.7	72.1	41.8	33.0	29.4
SR	116.6	137.5	72.0	42.0	16.1
SUP	108.4	131.3	54.0	30.2	7.2
Standby Procured	**26.0**	**18.8**	**13.8**	**13.0**	**12.1**
RR	9.8	6.4	4.4	4.6	7.8
SR	12.2	9.2	7.1	6.5	3.5
SUP	4.0	3.2	2.2	1.9	0.8
Standby Activated	**4.6**	**9.7**	**3.0**	**20.1**	**2.0**
RR	0.8	3.0	0.8	0.4	0.3
SR	3.1	5.7	1.7	13.3	1.3
SUP	0.7	1.1	0.5	6.4	0.4
Total	**326.2**	**369.3**	**184.5**	**138.3**	**66.7**
Total Volume (GWh)					
	2012	**2013**	**2014**	**2015**	**2016**
Active Procured	**5,901.3**	**6,019.2**	**6,005.9**	**5,333.3**	**5,262.0**
RR	1,405.2	1,400.8	1,400.0	1,399.4	1,405.6
SR	2,250.4	2,310.2	2,303.3	1,967.1	1,927.8
SUP	2,245.7	2,308.2	2,302.6	1,966.7	1,928.6
Standby Procured	**2,132.9**	**2,144.5**	**2,142.4**	**2,140.3**	**2,048.6**
RR	874.1	871.5	871.0	873.0	823.1
SR	917.1	915.1	916.0	938.7	918.3
SUP	341.7	357.9	355.4	328.6	307.2
Standby Activated	**58.0**	**76.8**	**64.8**	**135.7**	**85.1**
RR	6.0	12.9	9.0	7.6	7.9
SR	38.4	50.2	39.3	86.2	54.1
SUP	13.6	13.8	16.5	41.9	23.2
Total	**8,092.1**	**8,240.5**	**8,213.2**	**7,609.3**	**7,395.8**
Average Cost ($/MWh)					
	2012	**2013**	**2014**	**2015**	**2016**
Active Procured	**50.11**	**56.62**	**27.93**	**19.73**	**10.00**
RR	50.29	51.46	29.85	23.58	20.90
SR	51.81	59.50	31.27	21.37	8.34
SUP	48.29	56.87	23.43	15.36	3.73
Standby Procured	**12.19**	**8.76**	**6.42**	**6.07**	**5.89**
RR	11.23	7.35	5.08	5.25	9.49
SR	13.26	10.04	7.78	6.93	3.83
SUP	11.74	8.93	6.22	5.77	2.44
Standby Activated	**78.68**	**126.50**	**46.49**	**148.03**	**23.71**
RR	132.57	230.71	86.63	54.39	36.89
SR	80.42	113.51	43.42	154.29	24.16
SUP	50.19	76.50	31.97	152.20	18.21
Total	**40.32**	**44.82**	**22.47**	**18.18**	**9.02**

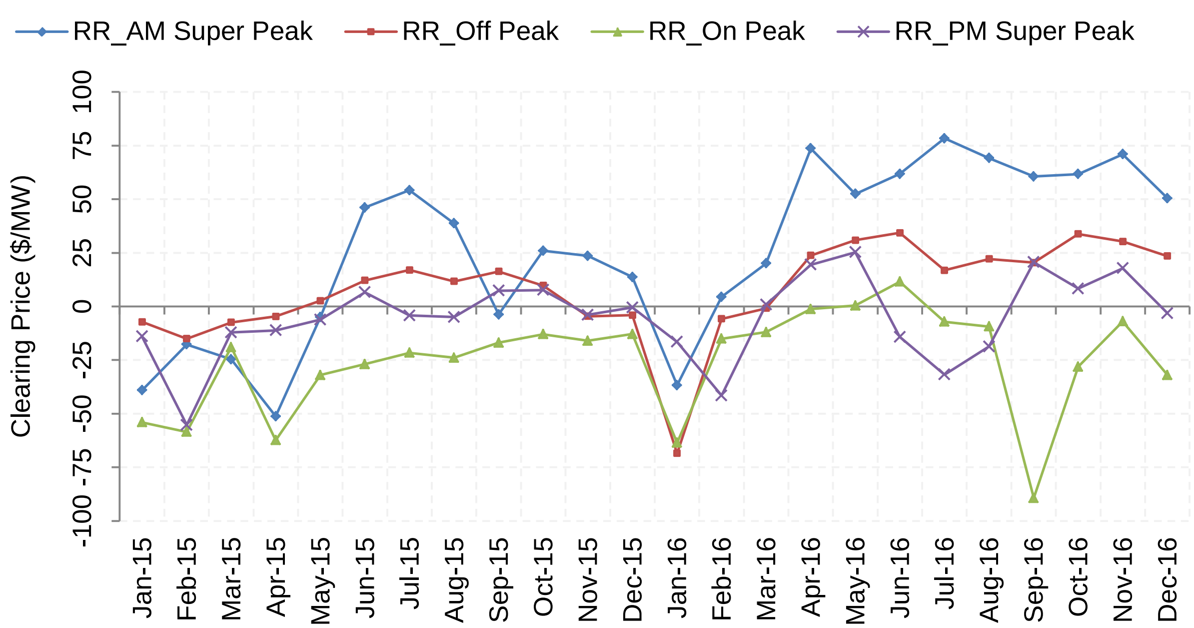
Figure 28: Average Price of Standby Regulating Reserve Premiums Paid During 2016



In its [Q2/2016 Quarterly Report](), the MSA noted that standby RR costs were high and that relatively little of the procured volume was ever activated. It was suggested that the AESO consider reducing the volume purchased from the market. Subsequently, on September 14, 2016 the AESO reduced the volume of standby RR that it purchases from 100 MW to 80 MW.

The clearing prices for active RR rose in 2016 (Figure 29). The most specialised products, the AM and PM Super-Peak RR, regularly price at, or close to, the price cap (AESO bid price). Notwithstanding this, the AESO rarely has a problem clearing its buy volume.

Figure 29: Average Monthly Clearing Price from 2015 to 2016 for Active Regulating Reserves



Net Revenue

For many years MSA has presented net revenue calculations in the energy and OR markets. It measures the margin in excess of short-run marginal costs for a hypothetical generator with specific characteristics. When the markets (energy and active OR) are efficient there should be no appreciable difference in net revenue across the markets unless some markets are tighter than others.

In this analysis we consider a simple cycle generator as the hypothetical new unit with characteristics similar to many of the new simple cycle generators that have been installed in Alberta in recent years. The assumed characteristics are shown in Table 6. The assumed operation of the generator is simple:

- In the energy market, the generator acts as a price-taker and produces when the pool price is greater than the cost of fuel (natural gas) plus variable operation and maintenance costs (O&M);
- When selling contingency reserves (spinning and supplemental reserves) the generator is a price-taker and we ignore any generation in contingencies;
- When selling RR, the generator is a price-taker and it produces at the mid-point of the regulating range and is assumed to receive pool price on this generation; and
- For super-peak RR products, the hypothetical generartor provides energy (and the implied net revenue) in the hours where it is not providing RR.

For each type of product, the margin over a period of time is the sum of the hourly net revenues less the fixed O&M costs.

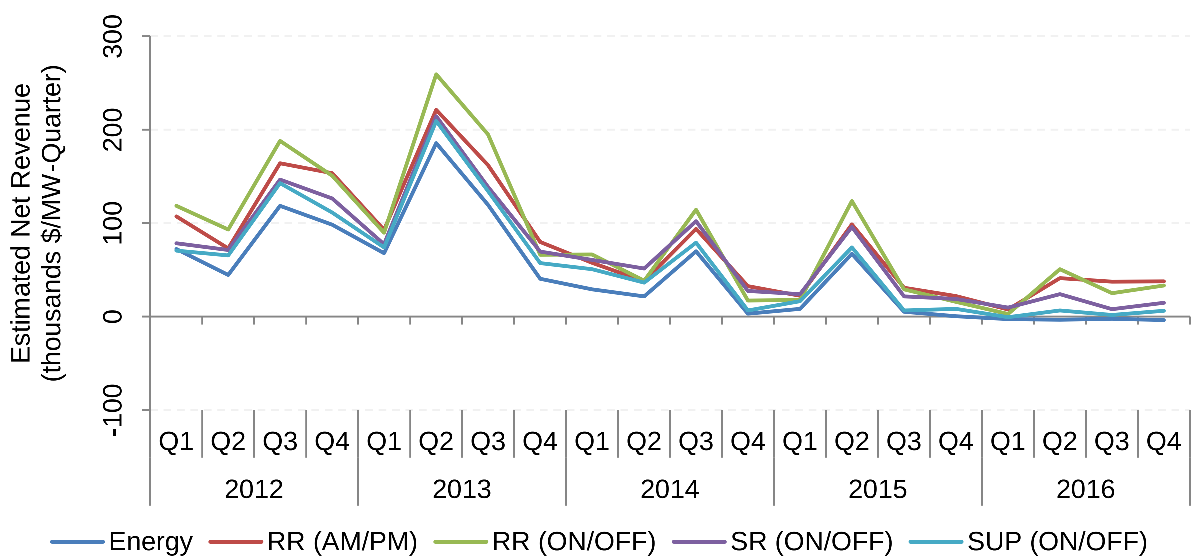
Figure 30 shows the net revenue results across the different markets. Net revenues in all markets declined from 2013 to 2016. In all years there is a premium for participating in the OR markets. For 2016, the net revenue from energy sales by the hypothetical generator was nearly zero. However, returns from sales into the OR markets were appreciably higher and were higher than in some previous years relative to the energy market. One might have expected some migration of sellers into the more profitable OR markets thereby reducing the arbitrage, but this did not appear to be the case. Additionally, net revenue appears to increase in all OR markets after Q2/2016, compared to the previous three quarters.

It is not clear at this point if these results are simply a function of the supply and demand fundamentals of each market or are a reflection of other factors such as the exercise of market power or some inherent inefficiency in the market design. During a year of historically low energy prices, one might expect more competition and participation in OR markets.

Table 6: Assumed Characteristics of a Simple Cycle Gas Turbine

Assumptions		
Heat rate	9.8	GJ/MWh
Availability factor	94	%
Proportion of active RR that provides energy	50	%
Variable O&M	6.00	$/MWh
Fixed O&M	18.00	$/kW-yr

Figure 30: Net Revenue per Installed MW[24]



Participation

As shown in Figure 31, from 2013 to 2016, there has been a general decline in the quantity of OR offers relative to what was procured; the latter has remained relatively stable, apart from around the change to BAL-002-WECC. Some of the largest declines in participation have been in the RR markets, which in 2016 was attributable in part to the cessation of offers from some thermal PPA units. In particular, Sundance C, Sheerness, and Keephills were providers of RR, and ceased participation after the notice of PPA terminations (see Table 7). This suggests that, at least some OR markets, the offer control dispute around the PPA terminations had a negative effect on competition.

[24] Based on the assumed costs of a simple cycle gas generator

Figure 31: Total Offers in WattEx Active Markets / Total AESO Procured (ratio, 2013–2016)

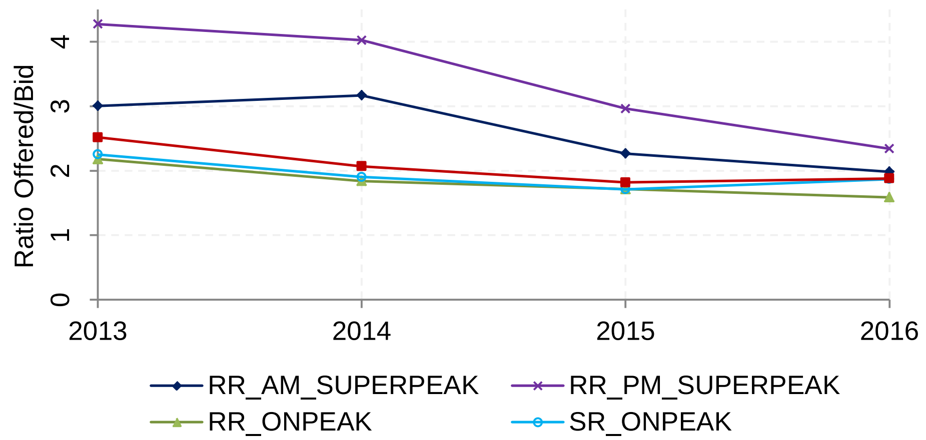


Table 7: Thermal PPA Unit Participation in WattEx

Unit(s)	Last date Unit(s) Participated in WattEx	Date Unit(s) Resumed Participation in WattEx (if during 2016)
Battle River 5 (BR5)	December 23, 2015	July 15, 2016
Keephills (KH1, KH2)	May 5, 2016	
Sheerness (SH1, SH2)	March 4, 2016	
Sundance C (SD5, SD6)	March 22, 2016	

Load Shed Service for Import (LSSi)

LSSi is a product that the AESO procures to arrest frequency decay in the event of the intertie tripping under high loading conditions. It is the product that, when armed, increases the maximum import levels in line with the aims of section 16 of the *Transmission Regulation.* LSSi uses devices that can trip the relevant load in a few cycles. LSSi is required when high levels of import are being offered, typically when pool prices are expected to be high. As noted above, pool prices in 2016 were not high and therefore there was less need for imports.

The LSSi is a product under contract with the AESO. The contracts involve a three-part payment scheme:

- Availability payment ($5/MWh)
- Arming payment (varies by provider)[25]
- Trip payments ($1,000/MWh)

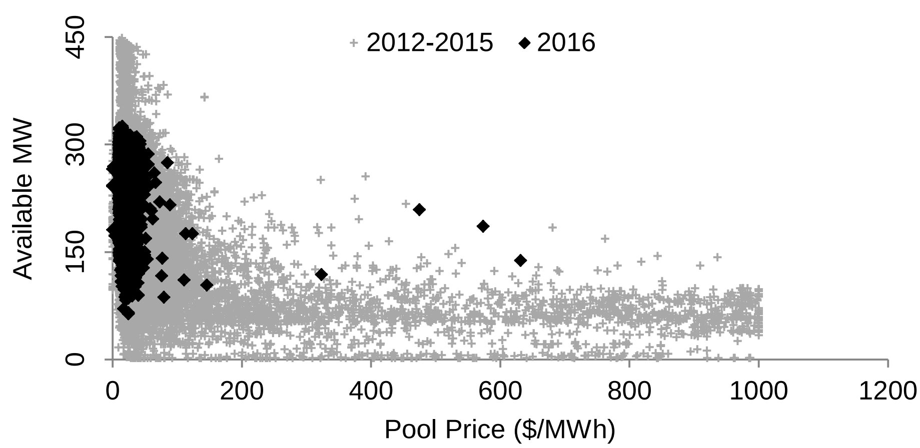
In 2016, $10 million was spent by the AESO on LSSi availability payments (Table 8). As indicated by the lack of arming payments in 2016, no LSSi was required to be armed, so 0 MWh

[25] Contracts are subject to a minimum arming guarantee amount over a period of time.

of extra imports were enabled. This means that there was no direct benefit to procuring LSSi in 2016, at least in terms of enhanced levels of imports, as this service was not called on.[26]

As noted in the MSA's Q2/2012 Quarterly Report, there were lower offered volumes of LSSi when higher pool prices occurred. As a result, less LSSi is available when importers are most likely to want to participate in the Alberta market, that is when import margins are greatest. Although there were very few high priced hours in 2016 for comparison (Figure 32), the MSA expects this situation to persist as the largest providers of LSSi continue to be loads that are generally price responsive.

Figure 32: Hourly Pool Price versus Available MW from 2012 to 2016[27]



In a November 2014 report,[28] the AESO cited two reasons for retaining the three-part payment structure: (i) to compensate for fixed costs and revenue uncertainty and (ii) to incentivise participation. Several years on, capital costs have been spent and so there is a strong argument in favour of removing both the availability payment and the minimum arming guarantee. In December 2014, the AESO determined that less LSSi was needed for a given level of imports and AIL.[29]

Changing the payment structure could be advantageous because LSSi payments would only go towards actual services provided. The MSA recommends that the AESO examine the three-part pricing structure and the volume of LSSi to be contracted prior to the expiry dates of the existing contracts in 2018. In Q4/2016 the total contract volume was 430 MW.

[26] The MSA did not detect any hours where there was demand for LSSi, nor was any LSSi armed. There were no instances of import volumes being constrained by a lack of available LSSi to arm.
[27] The figure excludes data points when Available MW = 0 during 1201L intertie outages.
[28] AESO Response to Stakeholder Comments on Assessment of Load Shed Service for Import (LSSi) Product, November 18, 2014, p. 9.
[29] AESO Intertie Restoration Information Session, May 28, 2015.

Table 8: Annual LSSi costs ($000s)[30]

Year	Availability Payment	Arming Payment[31]	Trip Payment	Total
2012	7,716	14,150	119	21,985
2013	8,626	9,192	170	17,988
2014	9,969	11,538	0	21,508
2015	9,336	1,235	122	10,693
2016	10,294	0	0	10,294
Total	45,941	36,115	412	82,468

Minimum Arming Guarantee

The total costs in Table 8 do not include minimum arming guarantee payments, and therefore do not match the costs for the LSSi program reported in the AESO's financial statements. In 2016, current estimates for minimum arming guarantee payments total eight million dollars, in addition to the $10 million availability payments, for a total program cost of approximately $18 million.

Annual Review Conclusion

Year 2016 was notable in the history of Alberta's electricity market due to both the unusual market conditions and announcements of future market changes.

In the wholesale market, the year was a period of historically high supply cushion and therefore a low average pool price could be anticipated. However, the 45% drop observed from 2015 likely resulted in large part from the offer behaviour corresponding to terminated PPA generators, as well as lower natural gas prices.

In the forward market, the amount of prompt month liquidity has remained relatively constant and appears unchanged after the PPA terminations, alleviating some concern about the potential impact of the terminations on RRO rates. The RRO remains about a third of traded prompt month volumes.

Regarding OR, the offer control dispute negatively affected competition because it led to a reduction of offer volumes, which decreased the coal participation on WattEx. The MSA also recommends that the contract design and volumes to be purchased for LSSi should be revisited prior to the expiry of the current contracts in 2018.

[30] Totals do not include the minimum arming guarantee. Some totals may differ from row and column sums due to rounding.
[31] Includes rearmed.

Activities

Regulated Rate Option (RRO) Report

On February 1, 2017 the MSA published a report titled Regulated Rate Option in Alberta's Rural Electrification Associations and Municipalities. This report examines how the RRO is provided in all areas of the province, including Rural Electrification Associations (REAs) and municipalities.

The **main conclusions** of this report are:

- Rates for about 95% of RRO-eligible load in the province are set though the Energy Price Setting Plan (EPSP) process outlined in the *Regulated Rate Option Regulation*, or are closely aligned with those rates. This includes the majority of municipalities and REAs.
- For the REAs that are not aligned with the main EPSPs, the RRO rates vary appreciably, although the majority are higher than the rest of the province (two have rates currently above 6.8 ¢/kWh). These REAs constitute a very small portion of total load.
- While the majority of RRO rates in the province are aligned with the EPSP rates, they are not exactly the same. There are 14 providers of RRO rates in the province, most of which offer different rates for different customer classes and zones.

Transition to a Capacity Market

On November 23, 2016, Alberta announced its intention to move to a capacity market design.[32] On January 18, 2017 the MSA released two reports that might be helpful to stakeholders in considering the challenge of transitioning away from coal towards increased renewable generation. As work on the detailed design of the capacity market begins, the MSA will look for opportunities to contribute our expertise on what constitutes a competitive market that will well serve Albertans from the perspective of both reliability and costs.

Renewable Electricity Program

The first round of the Renewable Electricity Procurement is set to take place in 2017. The MSA is interested in both the terms and structure of the procurement and the impact this has on competitiveness, both in the procurement itself and wider electricity market.

Forward market trading analysis

In November 2016 there were significant announcements related to the future of the Alberta electricity system. As with any significant announcement, prudency suggests examining forward market trading that occurs prior to the announcements being made public. At this time, the MSA's analysis has not found evidence of trading behavior which warrants further investigation. The MSA continues to monitor market activities for any contraventions as per its mandate.

[32] https://www.a berta.ca/electricity-capacity-market.aspx

Concerns regarding the timely declaration of outages

In September 2016, a market participant expressed concerns that several possible future outages may not have been declared in the AESO's Energy Trading System (ETS) in compliance with ISO rules Section 306.5: Generation Outage Reporting and Coordination. The market participant used public and trade sources to get information on possible outages and questioned whether those outages had been submitted into ETS in a timely manner. The MSA found these instances did not warrant investigation.

Self-report regarding erroneous restatements of excess energy offers

The MSA received a self-report in September from a PPA buyer whereby the buyer did not accurately restate the excess energy offer for the PPA owner. The PPA buyer self-reported the incident as a potential contravention under section 2(h) of the *Fair, Efficient and Open Competition Regulation*. In this case, offers were impacted for a short duration and by a relatively small amount. Given the circumstances in this case the MSA declined to investigate.

Self-report regarding trading on outage information

In October, the MSA received a self-report that described an incident where a real-time trader appeared to make a procedural error when routine offer restatements for an asset were incorrectly made prior to restating the available capability of another asset that was going on outage. Based on the information provided and historical offer data for the asset, the MSA found that there was no breach of section 4(1) of the *Fair, Efficient and Open Competition Regulation*. Thus, the MSA declined to investigate.

Complaint regarding the disclosure of personal information

In November, the MSA received a complaint from a member of an REA that suggested their REA contravened section 10(1) of the *Code of Conduct Regulation* by disclosing member's personal information without consent. The MSA notes that section 3(1)(b) of the *Code of Conduct Regulation* allows functions to be designated to other persons such that they comply with the Regulation with respect to those functions. The REA engaged with a contractor to conduct a survey on behalf of the REA which would require the REA to disclose member information to the contractor.

In this case, the MSA found that the REA had signed a confidentiality agreement with the contractor. The obligations set out in the confidentiality agreement reasonably protect the information of the REA members and prevents the disclosure of personal information by the contractor. On this basis, there was no evidence of a breach of the Regulation. The MSA declined to investigate.

Self-report regarding sharing of OR information

The MSA received a self-report from a market participant in November describing an incident where the market participant emailed OR volume information for three of their assets for the next two days to another market participant. The MSA reviewed the information submitted in the self-report and is satisfied that the OR volume information disclosed is not material. Also, as a result of this incident the market participant implemented an automated process that replaces sending OR volume information manually through email. The MSA declined to investigate.

The MSA would like to reiterate that market participants should implement controls to minimize the need to email sensitive information and exercise special precautions when sending emails containing such information.

Q4/2016 Appendix

The following tables and figure are provided for reference, and relate to Q4/2016 rather than the annual review.

Table 9: Q4/2016 Summary

		2015	**2016**	***Change***
Pool Price ($/MWh)	October	21.47	25.37	*+18.2%*
	November	21.17	16.32	*-22.9%*
	December	20.93	24.21	*+15.7%*
	Q4	**21.19**	**22.03**	***+4.0%***
AECO-C Gas Price ($/GJ)	October	2.47	2.94	*+19.1%*
	November	2.41	2.68	*+11.3%*
	December	2.18	3.22	*+47.5%*
	Q4	**2.35**	**2.96**	***+25.6%***
Avg Demand (AIL)	October	8935	9091	*+1.8%*
	November	9459	9542	*+0.9%*
	December	9834	10177	*+3.5%*
	Q4	**9409**	**9604**	***+2.1%***
Avg Wind Generation (MW)	October	536	413	*-23.0%*
	November	586	667	*+13.9%*
	December	580	614	*+5.9%*
	Q4	**567**	**563**	***-0.6%***
Avg Supply Cushion (MW)	October	2379	1662	*-30.2%*
	November	2466	2682	*+8.8%*
	December	2293	1968	*-14.2%*
	Q4	**2379**	**2095**	***-11.9%***

Table 10: Q4 Forward Trading Volumes (TWh)

		Annual	Quarterly	Monthly	Daily	Other	Total
2015	Oct	2.06	.23	2.00	.01	.00	4.30
	Nov	2.32	.21	2.11	.03	.01	4.67
	Dec	1.36	.54	1.77	.02	.02	3.71
	Q4	**5.74**	**.98**	**5.87**	**.06**	**.03**	**12.68**
2016	Oct	1.50	.66	2.21	.03	.09	4.49
	Nov	.98	.44	1.62	.01	.05	3.10
	Dec	1.30	.37	1.60	.05	.33	3.65
	Q4	**3.78**	**1.46**	**5.44**	**.09**	**.47**	**11.24**

Table 11: Q4/2016 Operating Reserves Summary

Total Cost ($ Millions)			
	Q4	**Q4**	***% Change***
Active Procured	**13.7**	**16.5**	***20.4***
RR	5.4	9.5	*77.6*
SR	5.3	4.4	*-16.8*
SUP	3.0	2.6	*-15.4*
Standby Procured	**1.9**	**2.0**	***3.4***
RR	0.8	1.2	*54.0*
SR	0.9	0.6	*-31.6*
SUP	0.2	0.2	*-32.6*
Standby Activated	**0.4**	**0.5**	***46.3***
RR	0.0	0.1	*130.4*
SR	0.2	0.3	*40.4*
SUP	0.1	0.1	*20.3*
Total	**16.0**	**19.0**	***19.0***
Total Volume (GWh)			
	Q4	**Q4**	***% Change***
Active Procured	**1,366.1**	**1,372.4**	***0.5***
RR	361.9	363.3	*0.4*
SR	502.2	504.4	*0.4*
SUP	502.0	504.7	*0.5*
Standby Procured	**528.8**	**485.9**	***-8.1***
RR	220.5	176.3	*-20.0*
SR	231.4	230.9	*-0.2*
SUP	76.9	78.6	*2.2*
Standby Activated	**15.2**	**20.3**	***33.1***
RR	1.8	1.6	*-10.8*
SR	9.3	12.9	*39.2*
SUP	4.2	5.8	*38.7*
Total	**1,910.2**	**1,878.6**	***-1.7***
Average Cost ($/MWh)			
	Q4	**Q4**	***% Change***
Active Procured	**10.0**	**12.0**	***19.9***
RR	14.8	26.2	*76.9*
SR	10.6	8.8	*-17.1*
SUP	6.0	5.1	*-15.8*
Standby Procured	**3.7**	**4.1**	***12.5***
RR	3.6	7.0	*92.6*
SR	3.9	2.7	*-31.5*
SUP	3.2	2.1	*-34.1*
Standby Activated	**24.3**	**26.7**	***9.9***
RR	25.2	65.0	*158.3*
SR	24.7	24.9	*0.8*
SUP	23.0	20.0	*-13.2*
Total	**8.4**	**10.1**	***21.0***

Figure 33: Q4/2016 Summary