Q1/2016 Quarterly Report

January – March 2016

April 29, 2016

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

www.albertamsa.ca

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Wholesale Market

Summary

Weaker demand and an abundance of supply continue to place downward pressure on wholesale electricity prices. For coal generators we see lower production and as consequence lower emissions.

The pool price for the quarter averaged $18.11/MWh ($15.43/MWh ext. off-peak, $19.44/MWh ext. on-peak). Prices were 38% lower than the corresponding period last year and yet another historic low.

As shown on the quarter's summary graphs on the next page (Figure 4), there were no pool prices greater than $35/MWh after January 20, 2016. Low natural gas prices and lower demand have contributed to setting historic low average prices (Figure 3).

Table 1: Summary Statistics

		2015	2016	*Change*
Average Pool Price ($/MWh)	Jan	33.95	22.25	*-34.5%*
	Feb	32.83	17.22	*-47.6%*
	Mar	20.65	14.79	*-28.4%*
	Q1	**29.03**	**18.11**	***-37.6%***
Average Demand (AIL, MW)	Jan	9,820	9,869	*+0.5%*
	Feb	9,764	9,543	*-2.3%*
	Mar	9,349	9,201	*-1.6%*
	Q1	**9,640**	**9,538**	***-1.1%***
Average Natural Gas Price ($/GJ)	Jan	2.64	2.24	*-15.0%*
	Feb	2.64	1.71	*-35.4%*
	Mar	2.60	1.26	*-51.5%*
	Q1	**2.62**	**1.74**	***-33.8%***
Average Supply Cushion (MW)	Jan	2,138	2,412	*+12.8%*
	Feb	1,986	2,629	*+32.3%*
	Mar	2,240	2,305	*+2.9%*
	Q1	**2,126**	**2,445**	***+15.0%***

In this low pool price environment, coal generation relative to availability reached a new low in recent history. As shown in Figure 1, 77% of the available coal generation capability was used in Q1, compared to 95% to 96% between 2008 and 2011. There are several contributing factors to this trend. Wind generation has more than doubled since 2011 (Figure 2), Battle River 3 and 4 remain economically dispatched off, and low natural gas prices enable gas generators to be more competitive.

Figure 1: Q1 Coal Generation / Available

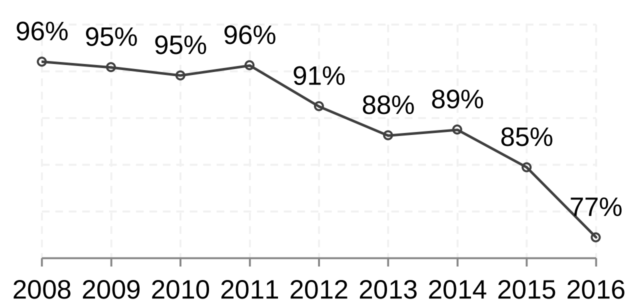


Figure 2: Q1 Total Wind Generation (GWh)

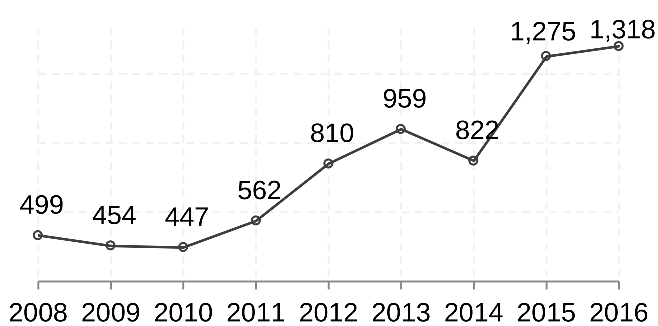
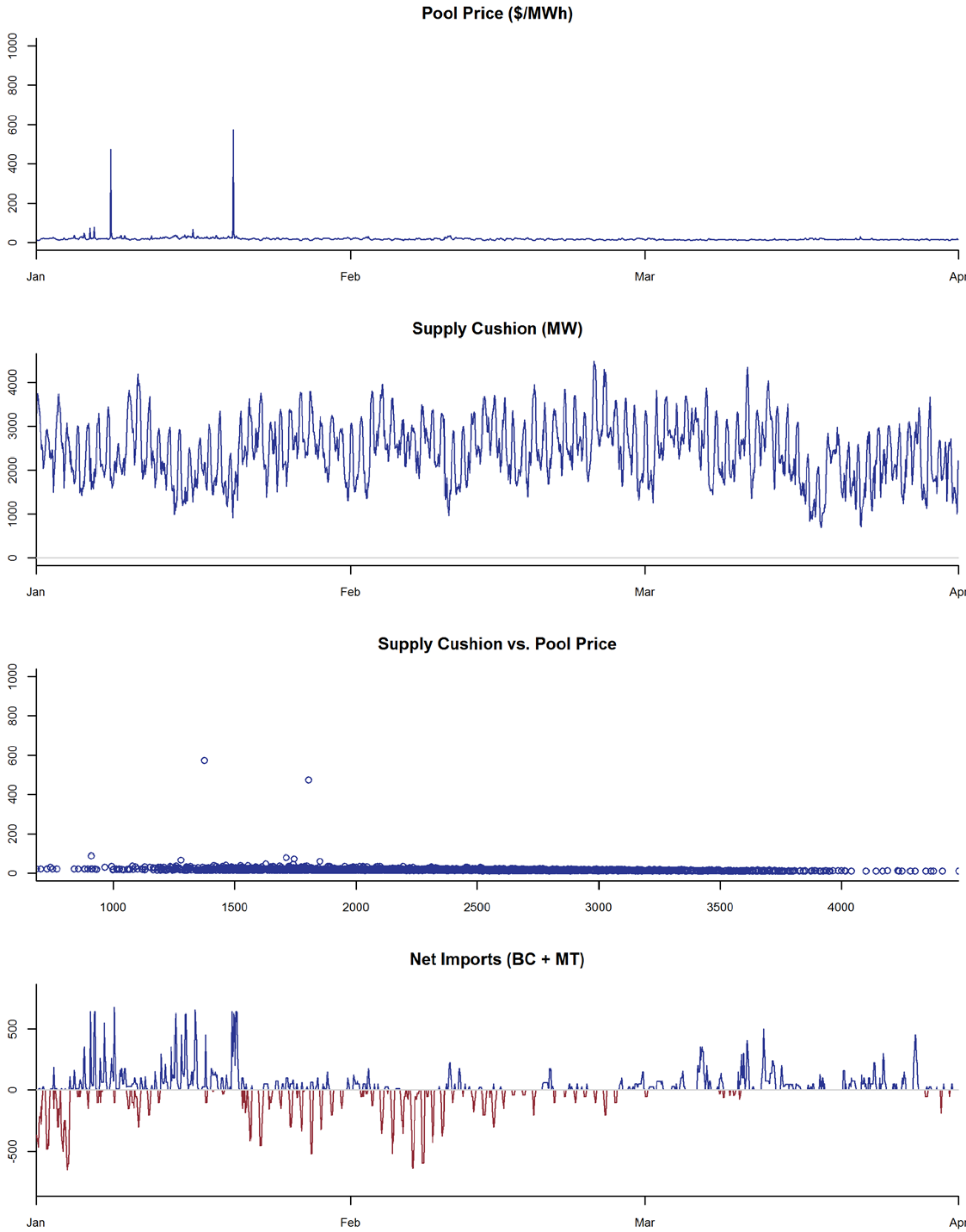


Figure 3: Average Quarterly Pool Price

Figure 4: Quarterly Summary



Demand

Average Alberta Internal Load (AIL) in Q1 declined 1.1% year-over-year, contributing to the increased average supply cushion. As shown in Figure 5, this comes after several years of consistent demand growth. At just under 21 TWh, load in Q1 2016 is 10% under the 2012 forecasted value, and about 5% under the 2014 forecast value.[1] As shown in Figure 6, the 2014 forecast anticipates approximately 20% more load in 2018 than 2015. The AESO is expected to publish a new long-term outlook in 2016. The 2016 long-term outlook will likely further revise downward the demand forecast.

Figure 5: Growth in Alberta Internal Load (% year over year)

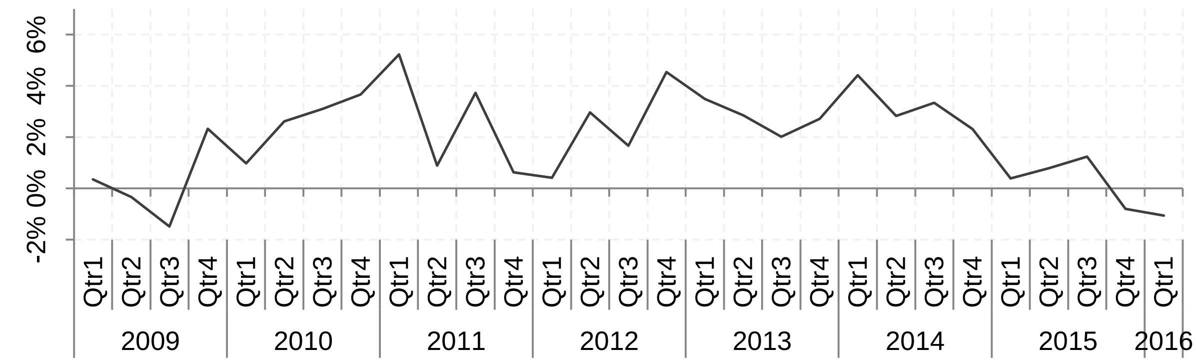
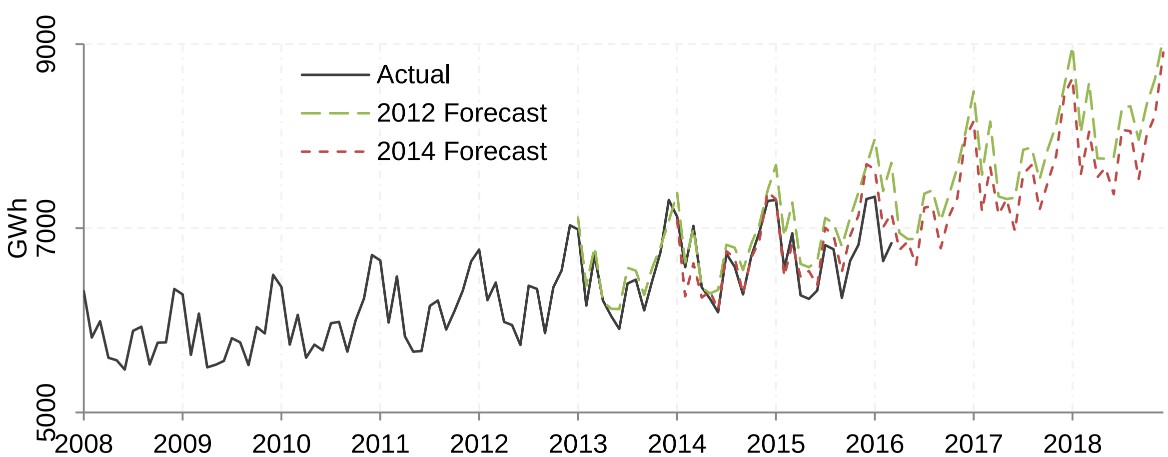


Figure 6: Alberta Internal Load (GWh)



[1] AESO 2012 Long-term Outlook and AESO 2014 Long-term Outlook data files.

Coal and Natural Gas

The amount of coal generation in Q1 2016 has declined to 77% of its available capability as a result of changing dynamics in the Alberta market (Figure 1).

The coal plants Battle River 3 and 4 have been offline for much of Q1 2016 and remain long-lead time. Long lead time units may declare full availability but are not immediately available and therefore do not appear in the merit order. Generators may wish to remain offline to avoid running minimum stable generation at pool prices insufficient to recover costs. On average there was about 300 MW less coal in the merit order than in Q1 2014.

For the remaining volume of coal, Figure 7 shows that considerably less was priced above $150/MWh on average during the peak hours of Q1 2016. Overall, less than 1% of coal available for market dispatch during on-peak hours was priced above $150/MWh, compared to 4% in Q1 2014. Factors contributing to this include less opportunity to withhold due to the increased overall supply cushion, and the announced return of PPA units to the Balancing Pool.

Total coal generation has declined, in part due to the increased competitiveness of natural gas generation. Figure 8 and 9 show natural gas prices have fallen during Q1 2016 and generally since the beginning of 2014.

Figure 7: Avg Coal Capacity Priced Above $150/MWh (on-peak, excluding long lead time units)

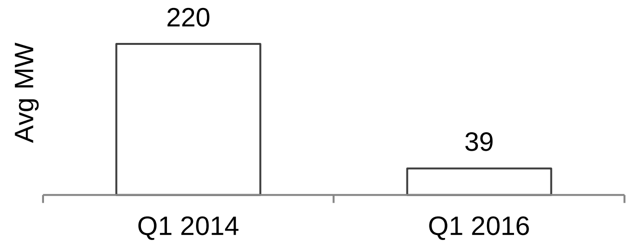


Figure 8: Q1 2016 Natural Gas Price (AECO-C)

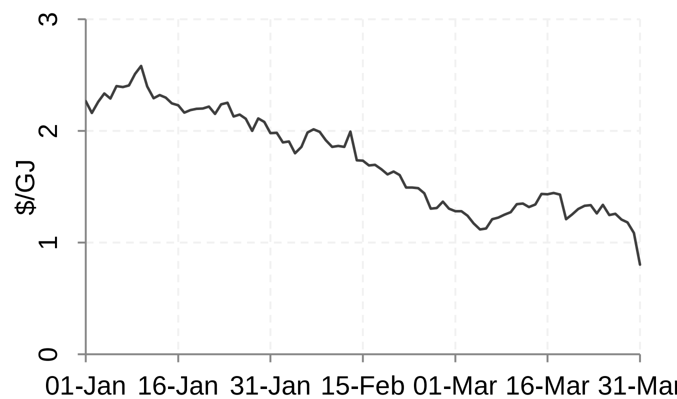
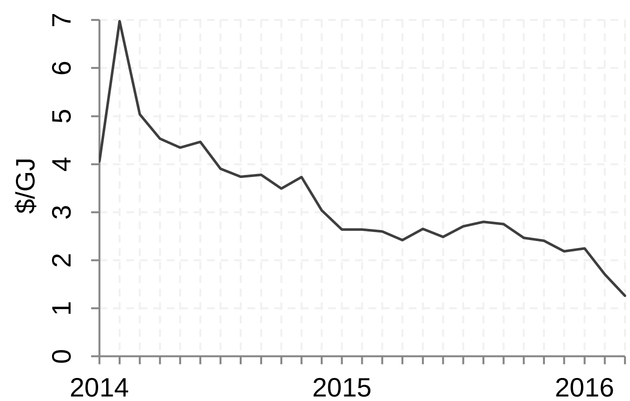


Figure 9: Monthly Avg Natural Gas Price (AECO-C)



A lower price of natural gas means a reduction of cost for natural gas generators. Figure 10 shows the average offer curves for both natural gas and coal generators during on-peak hours. It shows that both the absolute quantity of natural gas offered has increased relative to Q1 2014, and considerably more capacity was offered below $30/MWh.

In contrast, the 2016 average offer curve for coal has slightly less total capacity (due in part to the Battle River units), and less capacity offered at high prices. In composite, Figure 11 shows the average on-peak merit order for Q1 2016. During the quarter, over 90% of system marginal prices (SMP) were below $22.51/MWh.

On January 1, 2016 the compliance payments under the *Specified Gas Emitters Regulation* increased from \$15 to \$20 per tonne $C0_2$-equivalent, and the reduction requirement increased from 12% to 15%.[2] This only has a minor impact on costs for coal generators and the MSA is of the view the other factors listed above are of greater consequence.

Figure 10: Average On-Peak Offers by Fuel Type[3]

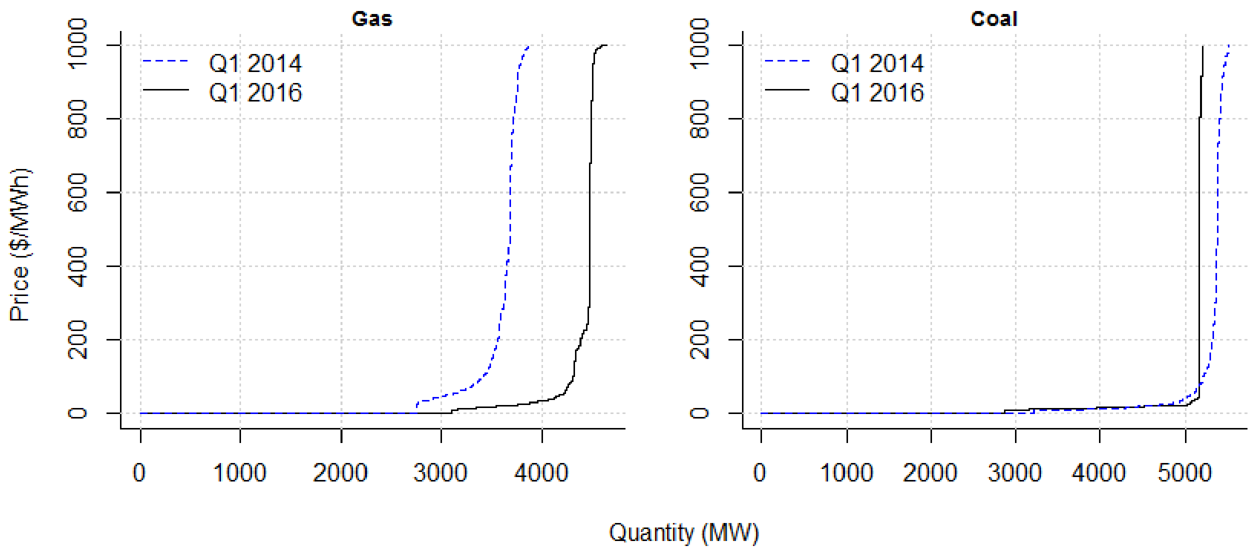
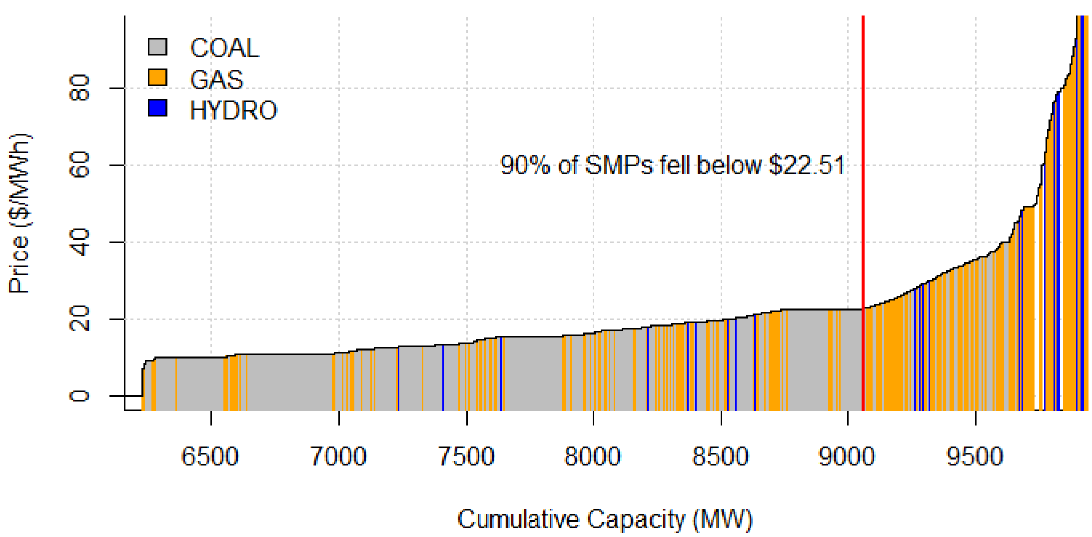


Figure 11: Average Q1 2016 On-Peak Merit Order (excluding wind and imports)



[2] Climate Leadership Report to Minister, November 20, 2015
[3] These merit orders are an aggregate of all on-peak merit orders in a quarter, divided by the number of on-peak hours.

Forward Market

With the notice of termination and possible return of PPA units to the Balancing Pool, there are implications for forward markets and RRO procurement. On March 2, 2016 the MSA released a feedback note about forward market purchases prior to PPA terminations due to a change in law.[4] The MSA is actively monitoring forward market volumes and the composition of forward market participants.

Overall forward market trading volume in the quarter was nearly 70% higher than in Q1 2015, with a tripling of the volume of annual contracts traded.

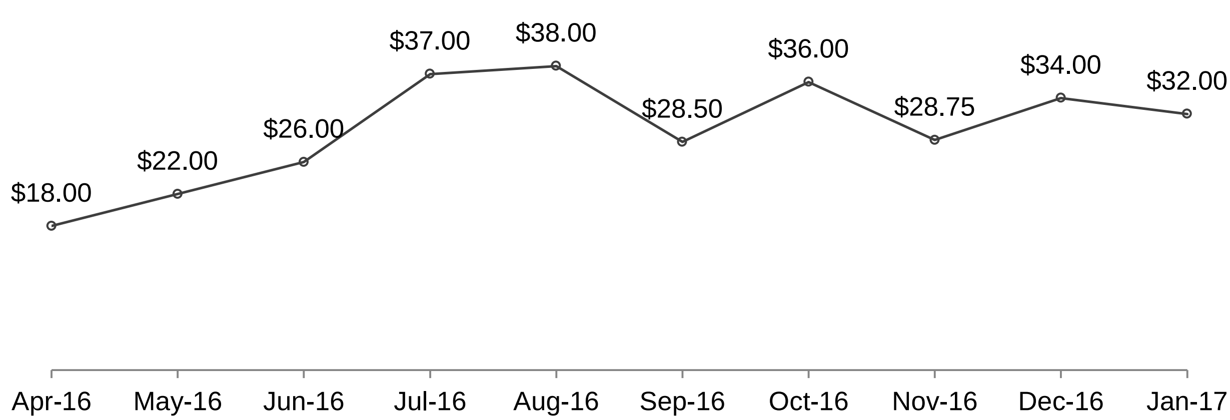
Table 2: Trade Volumes by Contract Term (TWh)

		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

* A small number of transactions made up a large fraction of the "other" volumes in Q1 2016.

As of March 31, all monthly flat forward contracts for the balance of 2016 were priced at $38.00/MWh or below.

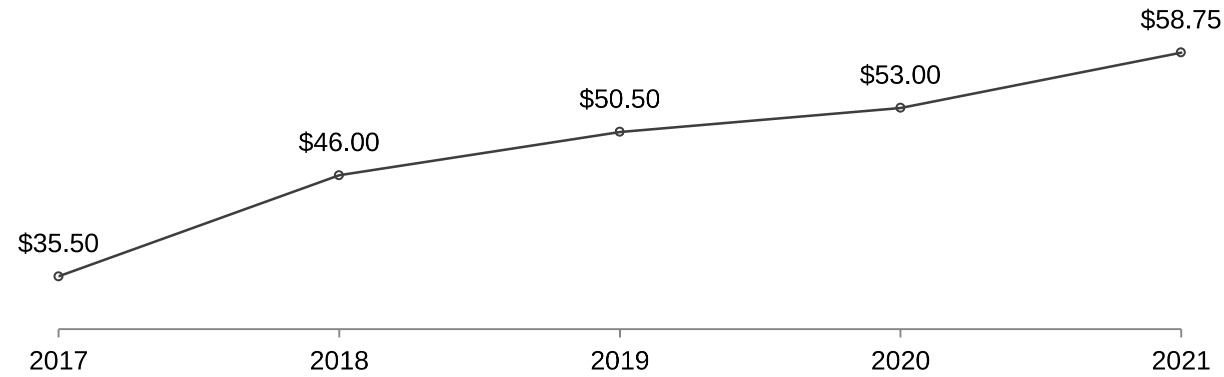
Figure 12: Monthly Flat Forward Curve as of March 31, 2016



[4] http://albertamsa.ca/uploads/pdf/Archive/0000-2016/2016-03-02%20Feedback%20-%20Forward%20Purchases%20and%20PPA%20Termination.pdf

The annual forward curve remains under $53.00/MWh through 2020.

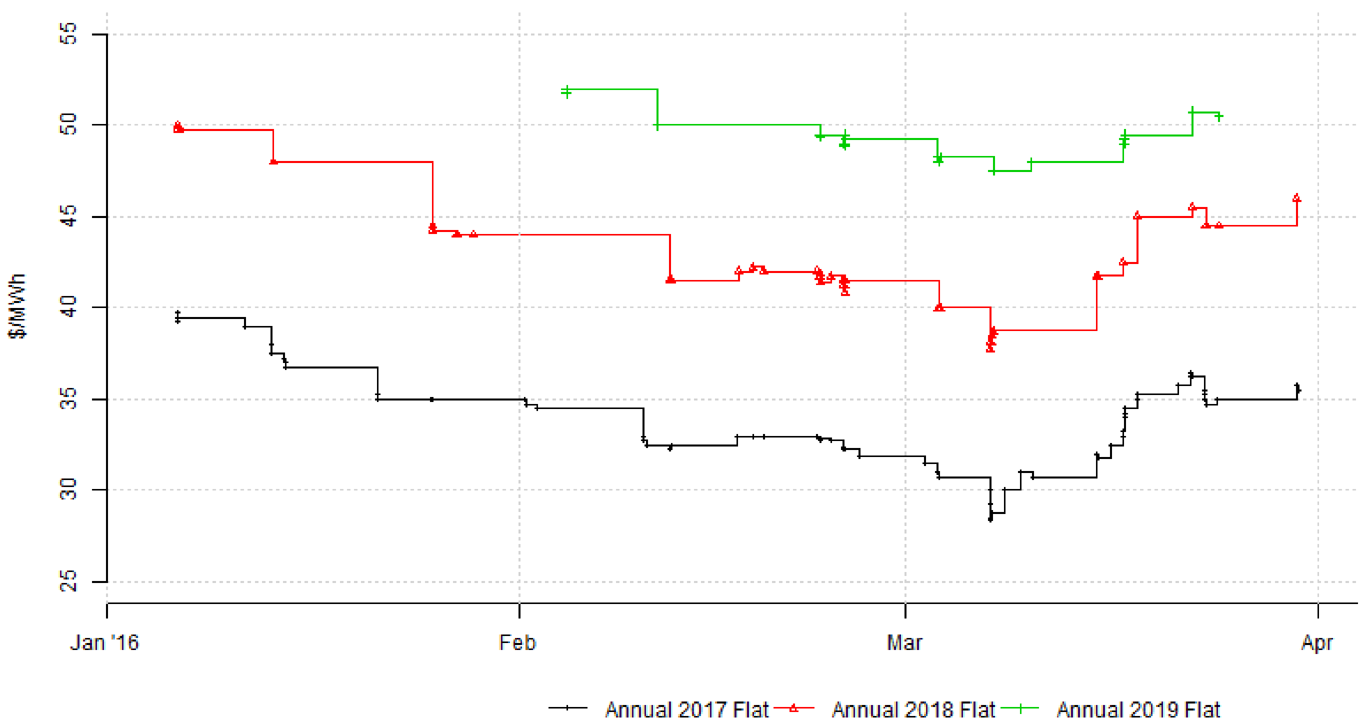
Figure 13: Annual Flat Forward Curve as of March 31, 2016



PPA Announcement Forward Price Impacts

Immediately following the March 7 announcement relating to the termination and possible return of the Sheerness, Sundance A, and Sundance B PPAs to the Balancing Pool, forward prices declined somewhat, but have since risen.

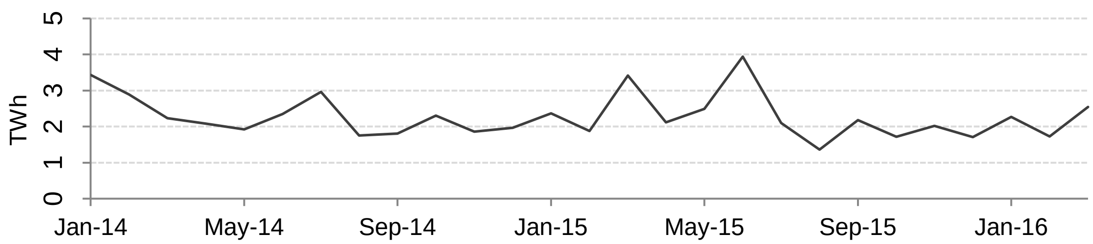
Figure 14: Annual Flat Forward Contract Trade Prices by Date



Volume of Near Month Contracts

The RRO procures forward contracts in the 20-120 day window before the delivery month, making up a significant portion of the buying volume in this period. A reduction in sellers in this circumstance could result in higher forward market prices which would flow through to the monthly RRO rates. However, as presented in Figure 15, the volume of monthly forward contracts traded for the four months following a given month has not decreased since the PPA announcements.

Figure 15: Volume of "Next Four Months" Monthly Contracts



Retail

Code of Conduct Transition

On January 1, 2016, *Code of Conduct Regulation*, AR 58/2015 came into force under both the *Electric Utilities Act* (EUA) and *Gas Utilities Act* (GUA). This new regulation is administered by the Alberta Utilities Commission (the Commission). Previously, the MSA had responsibility for the *Code of Conduct Regulation* under the EUA while the Commission was responsible for that under the GUA.

Final reporting for 2015 has now been received by the MSA and passed on to the Commission. The Commission is working with affected parties to develop new compliance plans and reporting requirements.

As a result, three documents on the MSA's web site were revoked on April 11, 2016. They are:

1. Guideline – Code of Conduct Reporting (March 4, 2004);

2. Feedback – Code of Conduct Regulation (EUA) (November 16, 2011); and

3. Feedback – Providing Information About Retailers (January 30, 2012).

In addition, there was a hearing procedure in connection with affected companies applying for exemptions from aspects of the Code of Conduct that was no longer relevant and revoked at the same time.

Bad debt collection via the RRO bill

In 2015, the MSA became aware of a business practice between an RRO provider and the RRO's affiliated competitive retailer that caused concern.

In Alberta, it is common for an RRO provider and its affiliated retailer to have a service-level agreement pursuant to which the RRO provides services to the affiliate, covering a range of areas including billing and customer care. The particular business practice that concerned the MSA related to the handling of bad debt incurred by the RRO's unregulated affiliate. In this case, under the terms of the service-level agreement, the RRO provider agreed to purchase bad debt from the affiliated retailer. In Alberta, any customer that does not have a retail contract automatically becomes an RRO customer. Here, some of the customers with bad debt originally owed to the RRO's affiliate became RRO customers. The RRO provider then attempted to recover the (purchased) bad debt through subsequent RRO bills, treating the bad debt amount owed as senior to current charges on the bill.

Late in 2015, the MSA advised the RRO provider and its affiliated retailer that this bad debt recovery process, including the treatment of the amount as senior debt, concerned the MSA and that the process should cease. In part, the MSA's concern was that the RRO provider was undertaking a function not required by regulation which could benefit an affiliate, particularly as it related to mixing regulated and unregulated business in the regulated bill. The practice also raised other potential Code of Conduct concerns. The MSA met with the parties in late in 2015 and requested that the process be stopped. The companies complied with the request and, as of April 1, 2016, will enlist such customers as new RRO customers without any reference to previous debts owed to the competitive affiliate. The outstanding debts owed by the customer to the affiliate will not be recovered by the RRO provider and will be collected through normal collections processes.

Operating Reserves

Summary

Total operating reserve costs fell 65% in Q1 2016 compared to Q1 2015, corresponding to a decrease in average pool price between quarters. The total cost of standby activations decreased by 93% in Q1 2016 compared to Q1 2015. This is due to a decrease in the volume of standby reserves activated by approximately 80%.

Active operating reserve costs for all products decreased 63% in Q1 2016 compared to the same quarter in the previous year. The cost for active supplemental reserve decreased the most, by approximately 83%. Active regulating and supplemental reserve prices decreased between 48 and 58%.

Net Revenue Analysis

Net revenues provide a useful means of placing market prices into context. The analysis makes an assessment of the ongoing revenues from participating the market after accounting for all ongoing operational costs. The estimated net revenues form a stream of cash flows to pay for investment costs and profit. Typically the comparison is made between revenue streams from various market opportunities acting as a price taker in each case. In efficient markets the comparison of net revenues for selling OR products to those from selling directly into the power pool is relevant.

In the MSA's Q3 2013 report, the MSA conducted a net revenue analysis to identify any arbitrage opportunities between the operating reserves market

Table 3: Total Cost of Operating Reserves ($ Millions)

	Q1 2015	Q1 2016	*% Change*
Active Procured	**17.4**	**6.4**	***-63.2***
RR	4.6	2.4	*-47.8*
SR	7.4	3.1	*-58.1*
SUP	5.4	0.9	*-83.3*
Standby Premium	**2.3**	**1.2**	***-47.8***
RR	0.7	0.6	*-14.3*
SR	1.3	0.6	*-53.8*
SUP	0.4	0.1	*-75.0*
Standby Activated	**2.9**	**0.2**	***-93.1***
RR	0.06	0.04	*-33.3*
SR	2	0.2	*-90.0*
SUP	0.8	0.04	*-95.0*
Total	**22.6**	**7.9**	***-65.0***

Total Volume of Operating Reserves (GWh)

	Q1 2015	Q1 2016	*% Change*
Active Procured	**1,377.4**	**1,348.7**	***-2.1***
RR	347.5	353	*1.6*
SR	515.4	497.8	*-3.4*
SUP	514.6	497.9	*-3.2*
Standby Premium	**517.7**	**519.6**	***0.4***
RR	211.7	215.9	*2.0*
SR	227.6	227.9	*0.1*
SUP	78.3	75.8	*-3.2*
Standby Activated	**43.8**	**8.9**	***-79.7***
RR	2	1.1	*-45.0*
SR	28.5	5.8	*-79.6*
SUP	13.3	2	*-85.0*
Total	**1960.1**	**1891.1**	***-3.5***

Average Operating Reserve Costs ($/MWh)

	Q1 2015	Q1 2016	*% Change*
Active Procured	**12.64**	**4.77**	***-62.3***
RR	13.27	6.78	*-48.9*
SR	14.28	6.3	*-55.9*
SUP	10.56	1.81	*-82.9*
Standby Premium	**4.53**	**2.34**	***-48.3***
RR	3.45	2.62	*-24.1*
SR	5.56	2.43	*-56.3*
SUP	4.44	1.28	*-71.2*
Standby Activated	**65.11**	**25.04**	***-61.5***
RR	29.88	31.6	*5.8*
SR	71.58	25.94	*-63.8*
SUP	56.67	18.88	*-66.7*
Total	**11.53**	**4.16**	***-63.9***

and the energy market. However, the analysis did not consider arbitrage that could exist between on-, off-, and super-peak products because super-peak products were not traded on WattEx until the end of 2011. In particular, regulating reserve is transacted for ramping products: super-peak AM and PM, in addition to on- and off-peak products. In Q1 2016, average on- and off-peak regulating reserves equilibrium prices[5] were lower than equilibrium prices for super-peak AM and PM indicating that the super-peak products are more expensive and that there may be an arbitrage opportunity.

In this report, we borrowed similar cost assumptions from the analysis carried out in Q3 2013[6] to conduct a net revenue analysis to test for arbitrage opportunities between on- and off-peak periods and super-peak periods for regulating reserve. We assumed a simple cycle natural gas unit dedicated to providing one operating reserve product or energy for the entire quarter.

We also assumed the following: (i) while dispatched for regulating reserve, the unit will provide 0.5 MWh of energy per MWh regulating reserve on average, receiving pool price minus marginal cost for the associated energy; (ii) the unit will provide in (a) both on- and off-peak periods or (b) both super-peak periods; (iii) because super-peak AM and PM does not cover all hours of the day[7], when the unit is not dispatched to provide for super-peak regulating reserves it would have provided energy in the energy market when pool price was greater than its marginal cost; (iv) in the energy market, the unit will provide energy when the pool price is higher than its marginal cost; and (v) in all instances, an estimate of fixed operations and maintenance cost is accounted for.

The results suggest that in Q1 2016 for a peaking natural gas plant, there were minimal arbitrage advantages between providing on- and off-peak regulating reserves and providing solely super-peak regulating reserves. While super-peak equilibrium prices are generally higher than equilibrium prices for regulating reserves for the on- and off-peak peak periods, the lower number of super-peak hours and poor returns in energy inhibits excessive returns.

Cost Assumptions

Heat Rate (GJ/MWh)	10
Variable O&M ($/MWh)	0.55
Fixed O&M ($/MW-quarter)	14,000

Net Revenue ($/MWh)

	Q1 2015	Q1 2016
Energy	2,000	-10,000
RR	13,000	-1,000
RR Super-Peak	16,000	1000
SR	14,000	0
SUP	7,000	-10,000

The return in the spinning reserve market appear similar to the return from providing regulating reserve which suggests that there is no arbitrage advantage between those markets. The return from the supplemental reserve market is lower than the returns from the other operating reserve markets and decreased significantly between Q1 2015 and Q1 2016, which coincides with the

[5] The equilibrium price is the clearing price for the relevant product and is set at the mid-point between the bid price and the most expensive offer accepted by the AESO.
[6] MSA 2013 Third Quarter Report, November 20, 2013: http://albertamsa.ca/uploads/pdf/Archive/000-2015/2015-1123%20Retail%20market%20update%202015%20.pdf
[7] Super-peak AM hours being HE 6 to 8 and super peak PM hours being HE 17 to 24 (from November to January) or HE 18 to 24 (for all other months).

substantial decrease in average supplemental reserve cost between quarters. This is likely due to the presence of load participation in that market.

Additionally, there were negative or zero returns to participation in energy and operating reserves. The return from providing energy decreased significantly between quarters, in line with the decrease in average pool price. With the exception of supplemental reserve, providing operating reserves appear to provide higher returns than providing energy.

These results stand in contrast to the results of the analysis done in Q3 2013 where the rates of return were positive and, with the exception of the regulating reserve market, there were minimal arbitrage opportunities between markets. However, it should be noted that the previous scope of analysis was larger and that the market conditions were different, which led to different results. The work reported here suggests more long term analysis will be instructive and will be reported upon in future quarterly reports.

Regulatory

PPA Offer Control

On January 1, 2016, ENMAX terminated its PPA for Battle River 5.[8] Since then, TransCanada has announced its intention to terminate its Sheerness, Sundance A and Sundance B PPAs[9] and Capital Power has announced its intention to terminate the Sundance C PPA.[10] Under section 6(1) of the *Fair Efficient and Open Competition Regulatio*n, the AESO is required to identify and track the offer control information associated with each offer made to the power pool. Final offer control information is made public 60 days after the offers are made to the power pool. As of the end of the quarter, the offer control for all of the PPAs listed above remained with the respective PPA Buyer and had not been transferred to the Balancing Pool.

Self-Report of Sharing of Non-Public Outage Information

In February 2016, the MSA received a self-report regarding the sharing, between competitors, of non-public outage information. A real-time operator mistakenly sent information about normal maintenance outages to other market participants. The outage information in question related to outages scheduled more than two years into the future. While this information was sent to the AESO, although not required under ISO rules, it was not made public as the AESO outage graphs do not extend beyond two years. The self-report was made on a timely basis and the MSA was satisfied that the information shared in that case was not material. As a result, the MSA declined to investigate.

In considering the factors of this specific case, the MSA also considered whether there are any circumstances whereby outage records relate to a period more than two years into the future could be material. In 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. Market participants are advised to seek legal advice regarding the potential materiality of outage records that relate to periods more than two years in the future.

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[8] ENMAX Financial Review 2015, page 37: https://www.enmax.com/AboutUsSite/Reports/2015-Financial-Report.pdf

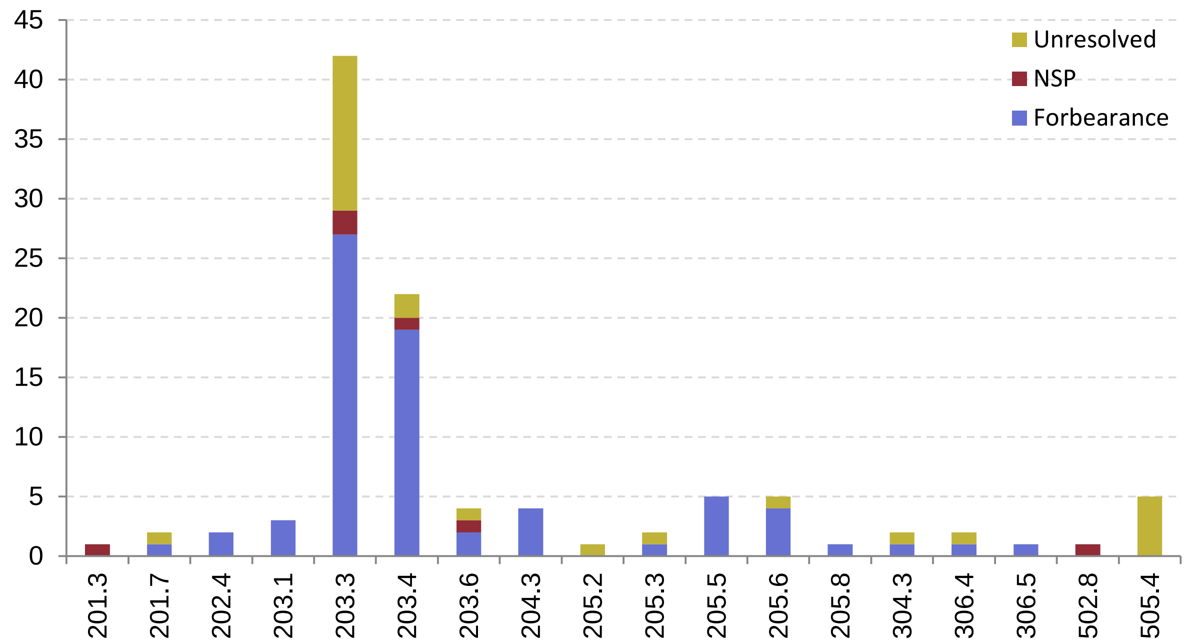
[9] TransCanada to Terminate Alberta Power Purchase Arrangements, March 7, 2016: http://www.transcanada.com/announcements-article.html?id=2031816&t

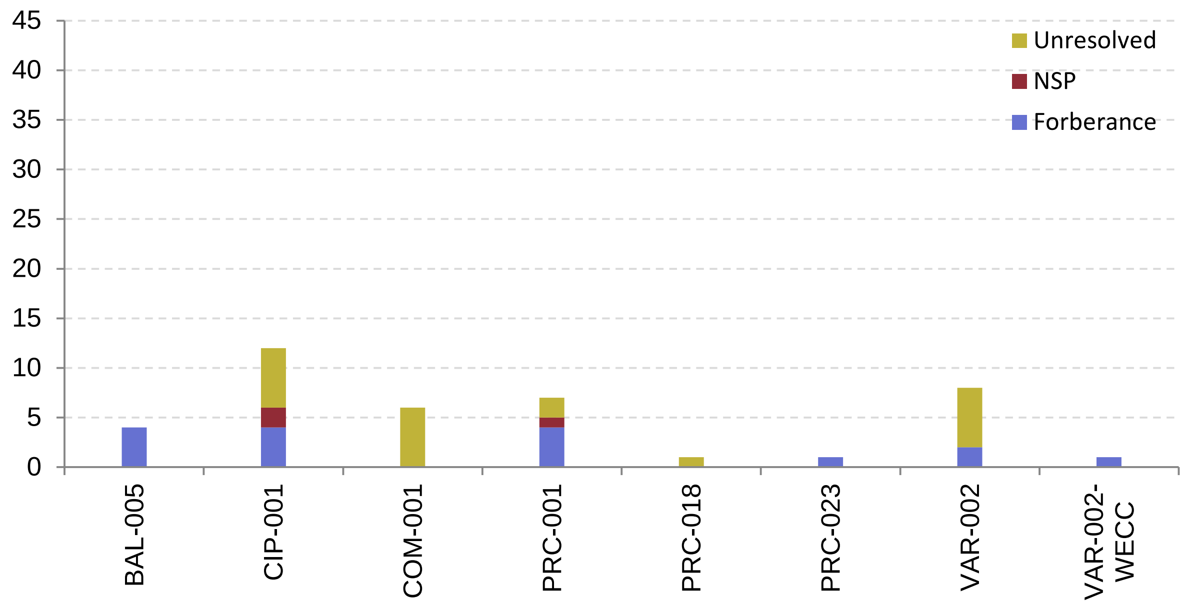
[10] Capital Power terminates Sundance C Power Purchase Arrangement, March 24, 2016: http://www.capitalpower.com/MediaRoom/newsreleases/2016/Pages/24-03-2016.aspx

Compliance

From January 1 to March 31, 2016, the MSA closed 78 ISO rules compliance files. Six files resulted in notices of specified penalty totaling $8,750.

For Alberta Reliability Standards, the MSA has closed 19 files since January 2016. Three of the files were notices of specified penalty issued in the fourth quarter of 2015 which remained open at the end of the year pending mitigation plan completion. The files were closed upon completion of the mitigation plans and the total financial amount of the notices of specified penalty was $18,750.





MSA releases

Notice re Judicial Decision - IPPSA v AESO (2016-03-15)

Feedback re Forward Purchases and PPA Termination (2016-03-02)

Compliance Review 2015 (2016-02-19)

Notice re Stakeholder Comments - OBEG Refresh (2016-02-02)

MSA 2015 Fourth Quarter Report (2016-01-29)

Notice re Employment Opportunity - Senior Advisor (2016-01-19)

Update from the Market Surveillance Administrator (2016-01-07)

Notice re Code of Conduct (2016-01-05)