Q2/2015 Quarterly Report

April- June 2015

September 2, 2015

Wholesale market

Summary

The average pool price in Q2/15 was $57.22/MWh ($75.57/MWh ext. on-peak, $20.52/MWh ext. off peak). The average pool price was about $15 higher than Q2/14 but below the 10-year average of $67/MWh.

		2014	2015	*Change*
Avg. Pool Price ($/MWh)	April	30.67	20.52	*-33.1%*
	May	54.05	53.93	*-0.2%*
	June	42.18	97.31	*+130.7%*
	Q2	**42.43**	**57.22**	***+34.9%***
Avg. Supply Cushion (MW)	April	2063	1996	*-3.3%*
	May	2012	1912	*-5.0%*
	June	2116	1885	*-10.9%*
	Q2	**2063**	**1931**	***-6.4%***
Avg. Demand (AIL, MW)	April	8830	8711	*-1.4%*
	May	8381	8378	*0.0%*
	June	8456	8783	*+3.9%*
	Q2	**8554**	**8621**	***+0.8%***
Avg. Outage (MC - AC)	April	2773	3825	*+38.0%*
	May	2985	3762	*+26.0%*
	June	3119	3349	*+7.4%*
	Q2	**2959**	**3647**	***+23.2%***
BC/MATL Combined ATC (MW)	April	509	368	*-27.6%*
	May	386	596	*+54.3%*
	June	494	729	*+47.6%*
	Q2	**462**	**565**	***+22.2%***
Total CDG (MWh)	April	22,348	690	*-96.9%*
	May	132,579	11,786	*-91.1%*
	June	1,759	6,053	*+244.2%*
	Q2	**156,685**	**18,528**	***-88.2%***
Avg. Gas Price ($/GJ)	April	4.53	2.42	*-46.5%*
	May	4.34	2.65	*-38.9%*
	June	4.47	2.48	*-44.4%*
	Q2	**4.44**	**2.52**	***-43.3%***

As indicated by the chart on the next page, a notable feature of this quarter is that the high price hours appear relatively high for the prevailing supply cushion. Supply remained robust even when multiple coal units were on outage, and thus the high prices appear driven by offer behaviour. The MSA examined four events over Q2/15, and found in each case an outcome that was unusual for the level of supply cushion, largely driven by the offer strategy of one market participant.

Economic withholding is not uncommon in the Alberta market. What's notable in this quarter is that withholding of over a thousand megawatts by one participant was more prevalent than in any quarter in the past two years.

As shown on the charts on the next page, the outcomes observed during the four events were not observed in April despite comparable levels of supply cushion. The April average pool price was $20.52/MWh, the lowest of any April since the market's inception.

Event 1: May 21 – 25

Over these five days in May, the pool price exceeded $500/MWh for 14 hours, with an average pool price during extended on-peak hours of $207/MWh. Average supply cushion during the extended on-peak hours was in excess of 1,300 MW. During hours with a pool price exceeding $100/MWh, a single market participant controlled over 70% (900 MW) of the undispatched supply remaining in the merit order.

Event 2: May 30

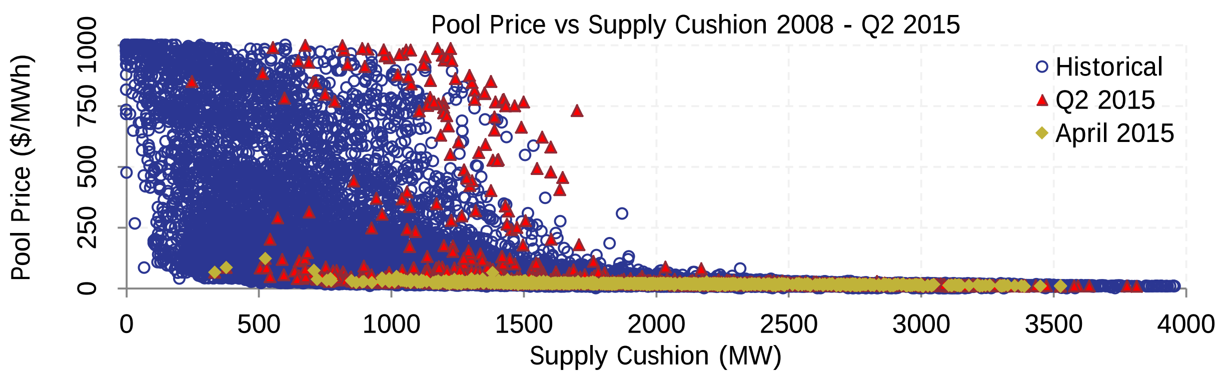
On May 30, the pool price exceeded $700/MWh for six hours (reaching a maximum of $935/MWh). The supply cushion during extended peak hours averaged 950 MW, suggesting tighter supply conditions than observed during Event 1. However, one market participant still controlled over 70% of the undispatched supply remaining in the merit order during the >$100/MWh hours.

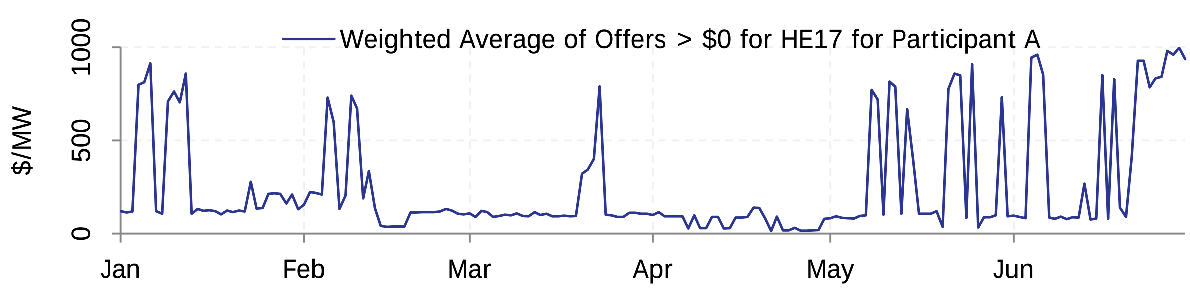
Events 3 and 4: June 4 – 5 and June 22 – 30

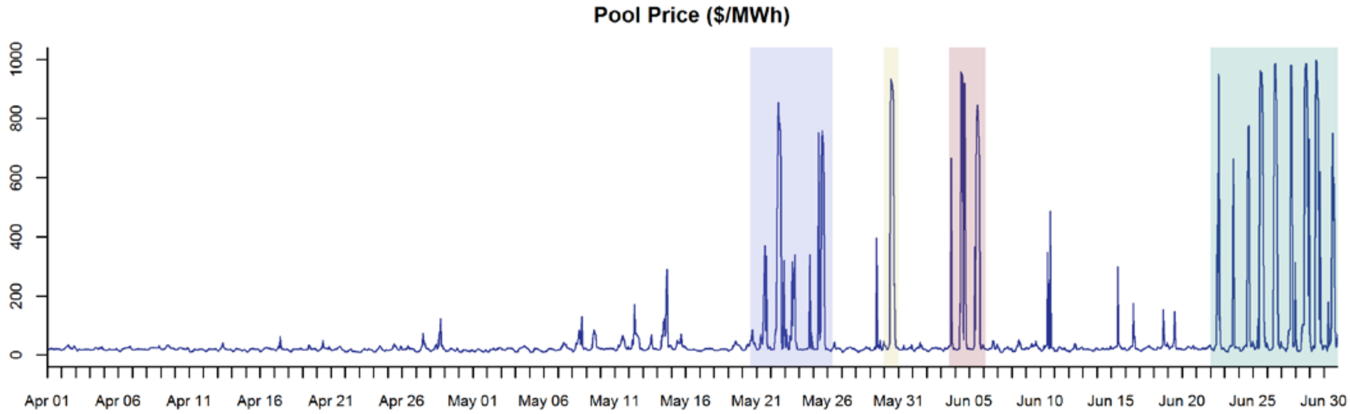
Two periods in June also exhibited high pool prices with market conditions similar to Event 1. During extended peak hours, these periods had average supply cushion levels above 1,400 MW and average pool prices in excess of $290/MWh. While Alberta experienced high temperatures during the end of June, supply cushion never dropped below 500 MW.

In hours with a pool price greater than $100/MWh, one market participant accounted for more than 85% of undispatched supply during the June 4-5 event (over 1,100 MW), and this same participant accounted for an average of 65% of undispatched supply during the June 22-30 period (over 800 MW). During the June 22-30 event, a second market participant made up approximately 20% of the undispatched supply during hours with a pool price in excess of $100/MWh.

The MSA still views the highlighted offer behaviour as constrained by market fundamentals outside of a relatively few hours but, as noted in the Forward Market section of the reprot, we are assessing the impact of this type of conduct on competition and liquidity in the forward market.






Pool Price ($/MWh)
0
200
400
600
800
1000
Apr 01
Apr 06
Apr 11
Apr 16
Apr 21
Apr 26
May 01
May 06
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May 16
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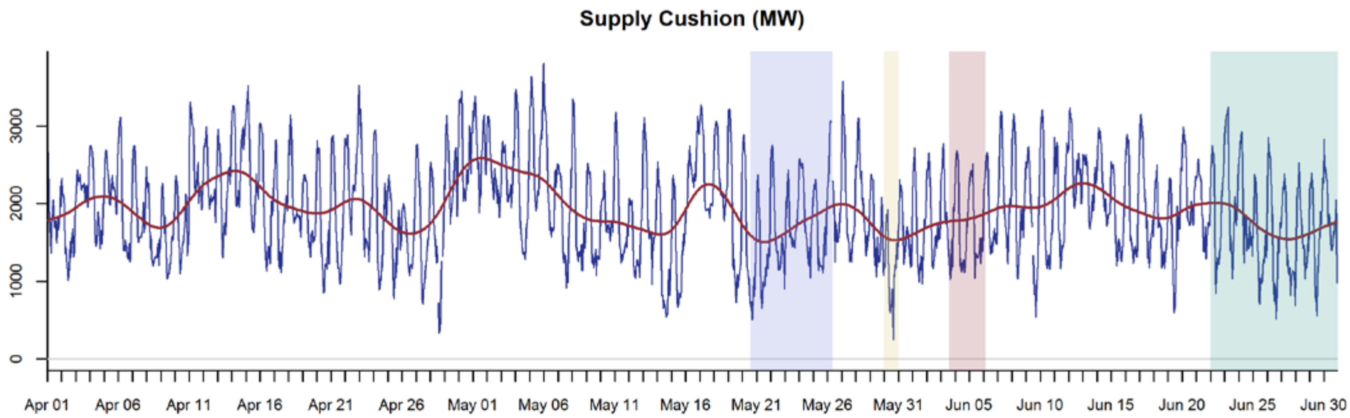
Jun 05
Jun 10
Jun 15
Jun 20
Jun 25
Jun 30


Supply Cushion (MW)
0
1000
2000
3000
Apr 01
Apr 06
Apr 11
Apr 16
Apr 21
Apr 26
May 01
May 06
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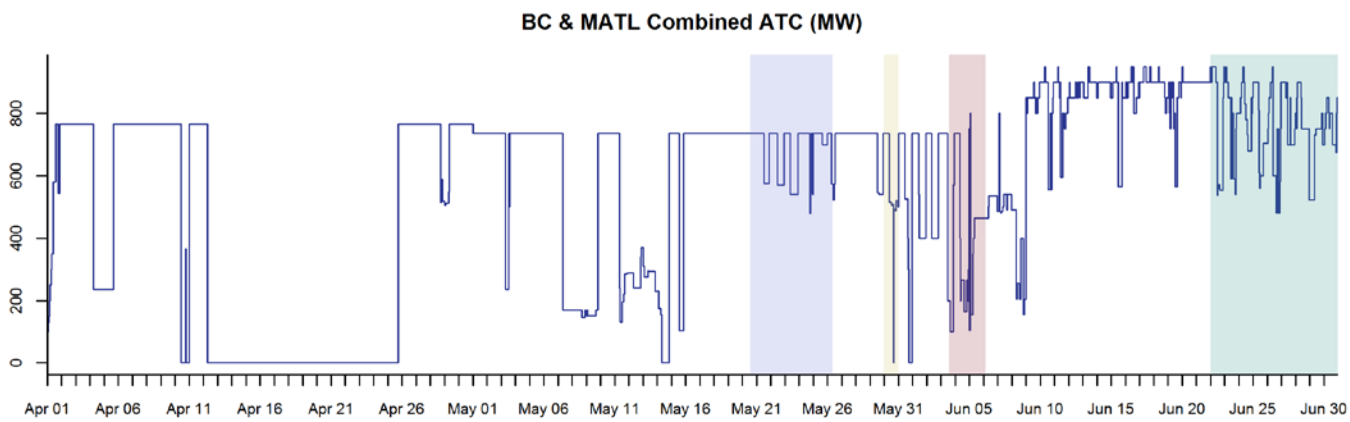
Jun 15
Jun 20
Jun 25
Jun 30


BC & MATL Combined ATC (MW)
0
200
400
600
800
Apr 01
Apr 06
Apr 11
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Jun 15
Jun 20
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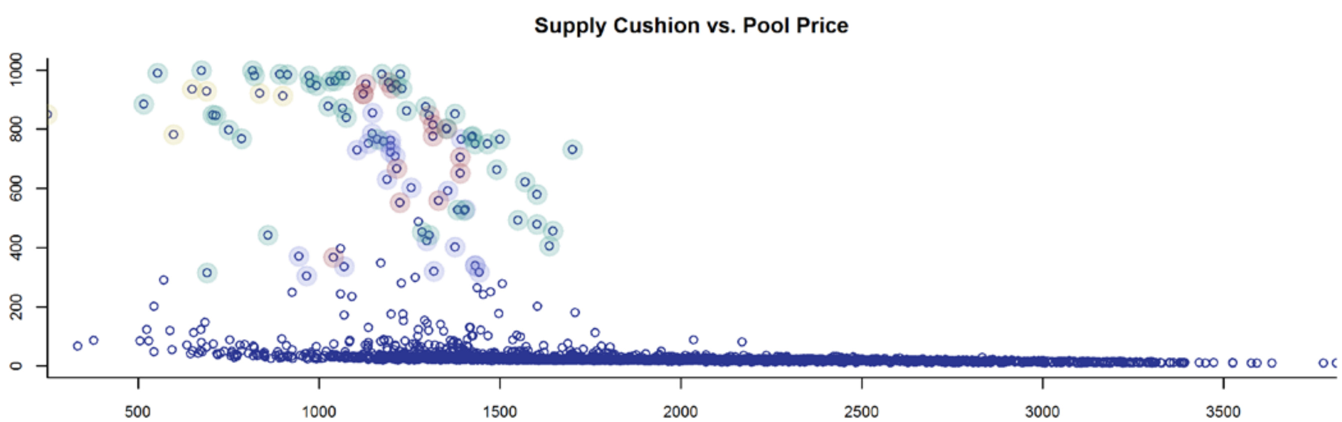
Jun 30


Supply Cushion vs. Pool Price
0
200
400
600
800
1000
500
1000
1500
2000
2500
3000
3500

Alberta Interties

ATC Postings

In its Q4/2014 Quarterly Report, the MSA commented on the accuracy of ATC allocation postings close to real time, and stated its intention to explore whether more accurate posting was possible. The MSA met with the AESO as well as other market participants to discuss the matter. The AESO has since requested stakeholder input on the process of posting intertie transfer capability and the MSA has participated.[1]

Impact of changes to LSSi requirements

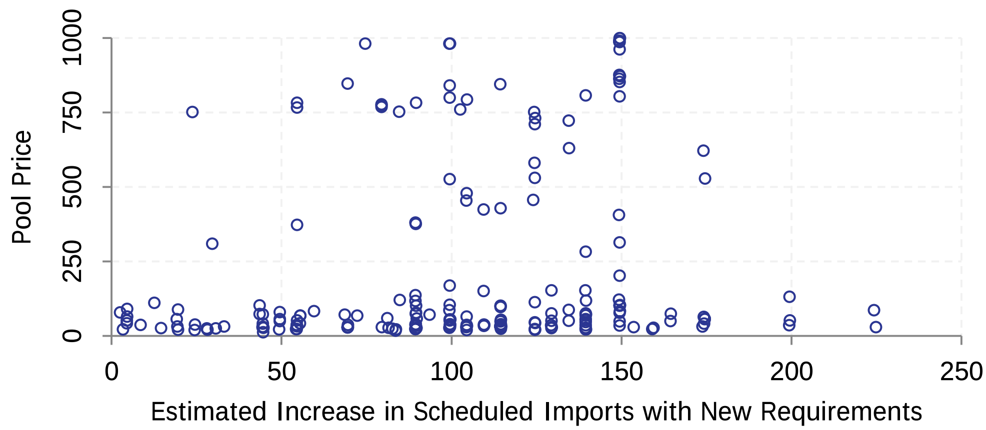
In December 2014 the AESO reduced the amount of LSSi required to support a given level of imports, based on the results of a study.[2] The modifications are a result of transmission reinforcement which reduced the volume of LSSi required to arrest frequency decay. While less LSSi is required, sufficient contingency reserves must be available for the line to operate at maximum capacity. The AESO does not always carry sufficient contingency reserves to allow full flow when the intertie becomes the largest single contingency. The purpose of the analysis herein is to look at the effect of the change in LSSi requirements over the past 6 months in terms of facilitating increased imports.

For each hour in the period January through June 2015 we constructed a counterfactual (simulated) import schedule based on the previous LSSi requirements, all else kept equal. In many hours there was no effect as the amount of imports was not constrained by capacity. In some hours, insufficient LSSi was offered in the counterfactual case to enable the actual schedule.

Over the six months, the analysis indicated a reduction of approximately 22,000 MWh of imports occurring over 218 hours due to the higher LSSi requirements that prevailed prior to December 2014. The increased imports of the first half of 2015 occurred in both high priced as well as low priced hours. At high pool price levels, an increase of 100 to 200 MW of imports can significantly mitigate those pool prices. The chart below plots the actual pool prices versus the increased imports.

[1] http://www.aeso.ca/downloads/Stakeholder_notice_re_transfer_capability_limits_process_072115.pdf

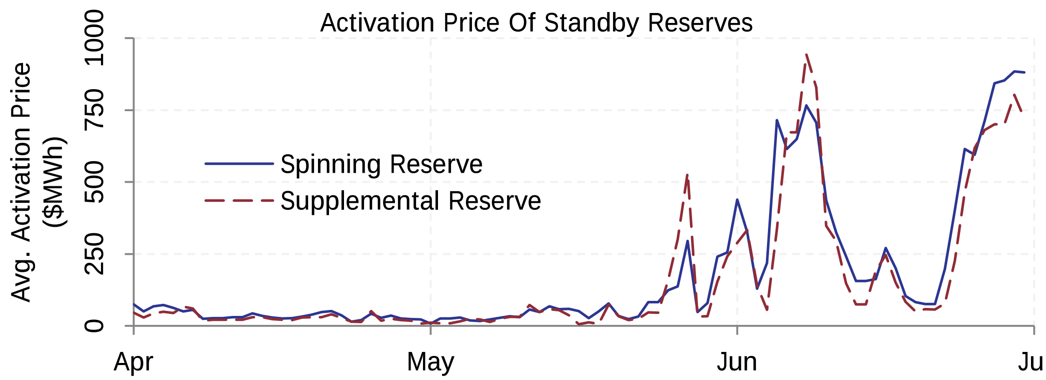
[2] http://www.aeso.ca/downloads/Intertie_Restoration_Stakeholder_Session_May_28.pdf, page 17.



Insufficient contingency reserves

As already noted in 2015 (January – June inclusive), the BC/MATL combined import available transfer capability was constrained due to insufficient contingency reserves in approximately 413 hours. Forecasting the level of imports day-ahead is difficult and frequently the AESO turns to its standby reserves, when available. As noted, in the first half of 2015 there was insufficient standby available to enable the full schedule to flow. The AESO is actively considering alternative mechanisms to address this issue.

One possible mechanism is to procure more standby reserves to enable additional imports. In Q2/15, the average price for activated standby spinning and supplemental reserve was over $200/MWh. The graph below shows the potential average activation prices over the quarter, which were considerably higher from late May and throughout June. Another factor for consideration is that most activated standby reserve is withdrawn from the energy merit order, which implies a swap of internal megawatts with imports, i.e. to enable an extra 10 MW of import to flow we take 10 MW out of the Alberta generation mix and hold it in reserve. Considering this, it is apparent that the efficiency of using standby reserves to enable imports will depend on the conditions in the spot market, as well as the activation prices of available standby reserve. In many hours, this would not appear to be an efficient method of increasing intertie capability and is worth further scrutiny.



Dispatchable wind

The AESO's Dispatchable Wind Rule Changes have been in effect since April 1, 2015.[3] Under these rule changes, wind assets are required to offer energy into the Energy Merit Order (EMO) similar to other generation assets in the province. Previously wind production did not offer into the EMO, but rather received the prevailing pool price for energy produced. Wind assets are now dispatchable and may offer energy at various price and quantity pairs.

Furthermore, as with other generating source assets, available capability for wind assets is defined in the AESO's consolidated authoritative document glossary as: "the maximum MW that the source asset is physically capable of providing".[4] As per the definition, this means that the available capability of a wind asset is its maximum capability less any outages on the turbines. In practice, the capability of wind assets to provide energy is constrained by prevailing wind conditions in real time. Information on wind conditions is provided to the AESO in real time through the potential real power capability obtained through telemetry. This potential real power capability is factored into the allowable dispatch variance for wind assets as the lower threshold for dispatch compliance in cases where real power capability is less than the amount of energy specified in the dispatch.

While wind assets now have the ability to choose their offer strategy, pure price-taking behavior was observed in this quarter, with wind assets offering their maximum capability at $0/MWh. Furthermore, wind assets were fully dispatched to their available capability throughout the quarter, less any ISO directives instructing otherwise. As a result, the new rule changes do not appear to have had any material effect on market outcomes or participant behaviour during the second quarter.

[3] http://www.aeso.ca/downloads/Notice_of_Filing_304_3_306_6_502_1(1).pdf

[4] http://www.aeso.ca/downloads/Consolidated_Authoritative_Document_Glossary_(July_8_2015).pdf

Complaint against ENMAX regarding its purchase of Balzac and Cavalier generating units

In December 2014 the MSA received a complaint from a market participant against ENMAX regarding its purchase of the Balzac and Cavalier generating units. The complaint alleged, among other things, that the Independent Assessment Report prepared pursuant to subsection 95(11) of the *Electric Utilities Act* was deficient. The complaint also alleged that ENMAX had violated section 95 of the EUA through its use of Alberta Capital Finance Authority (ACFA) funds, tax advantages associated with the Payment in Lieu of Tax (PILOT) program, and having a debt-to-equity ratio that exceeds that allowed by the Alberta Utilities Commission (AUC).

The MSA has previously concluded that its role with respect to s. 95 assessments is limited to assessing whether the municipality-owned utility has breached the terms of the approval or otherwise misled the Minister.[5] Neither was alleged in this complaint. With respect to the outstanding issues, the MSA determined that they do not warrant investigation because: (i) the issue is more appropriately addressed, or is being addressed, by the AUC or the Courts; and (ii) it is not apparent that any of the alleged benefits accorded to ENMAX have resulted in conduct that violated any section of the EUA or resulted in harm to the fair, efficient and openly competitive operation of the Alberta electricity market. Therefore this complaint did not proceed to a formal investigation. However, the MSA undertook to work with the Department of Energy to determine whether there are better ways to satisfy the purpose described in section 5(c) and specified in section 95(10) of the EUA than through the mechanism of an independent assessor.

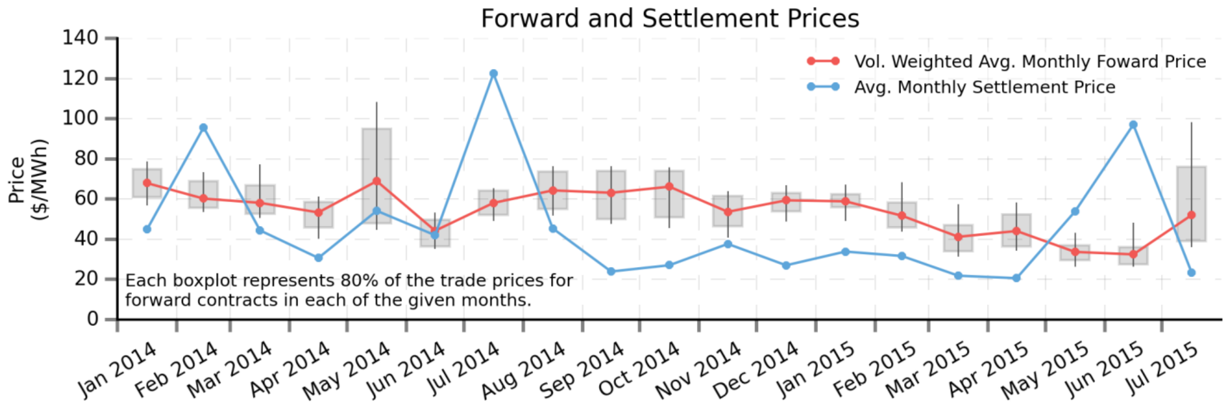
[5] MSA Q3 2014 Report, available: http://albertamsa.ca/uploads/pdf/Archive/00-2014/2014-11-06%20Quarterly%20Report%202014%20Q3.pdf

Forward market

Total TWh Traded			
	2014	**2015**	***Change***
Apr	3.6	7.5	108.4%
May	3.6	6.4	79.1%
Jun	4.4	10.4	136.5%
Q2	**11.6**	**24.3**	**110.1%**

Forward market liquidity increased by 110 % year-over-year for Q2 2015, with total trading volume climbing to 24.3 TWh. The increase in trading was largely dispersed across all three months in the quarter with the majority of increased trades stemming from a handful of large traders. There was a substantial increase in annual trades throughout the past quarter. Monthly trade volumes in June were double those in April and May, possibly related to the high volatility in the spot market in June. The increase in market liquidity is welcome news; however, it may not be sustained to the extent that some of the annual trades were to end users.

Forward contract prices continued their downward trend from January, although there was a significant uptick for the July contract. May and June 2015 were the first months since last summer where the forward prices were less than the monthly spot market prices. The figure below sets out the average monthly forward and spot market prices between January 1, 2014 and July 31, 2015.



July Contract Price

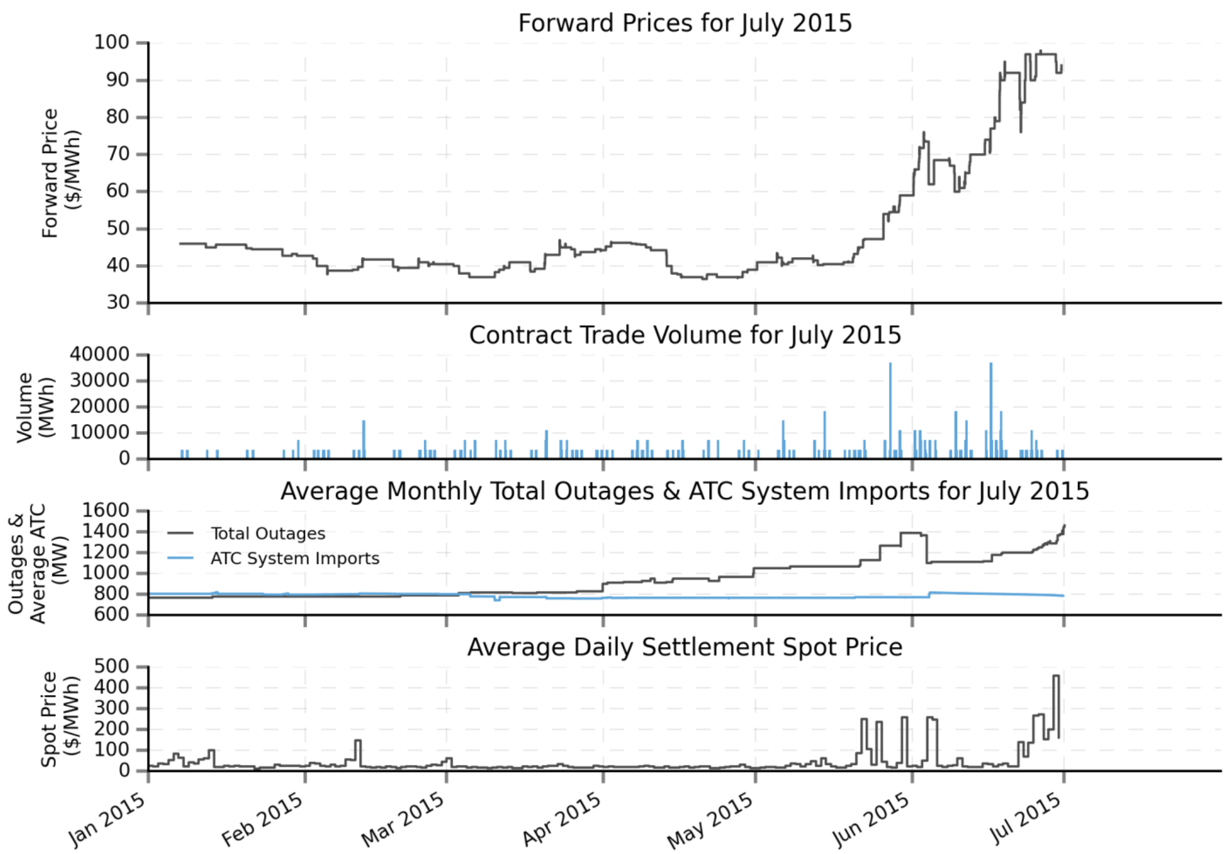
The July flat forward contract experienced a significant increase in price from late May to the end of June, with contracts trading as high as $98/MWh during the final week of the quarter. High trade volumes occurred during the last week of May and the third week of June, although the largest trade volumes do not directly coincide with a significant price movement.

The anticipation of warmer temperatures during the summer may have led to higher forward prices for July due to lower wind production, less efficient coal and gas units, and a higher system load. However, these influences may not adequately explain the run up in prices leading to July since it is assumed that these factors would likely have been built into all pricing models from the start.

Forward markets trade as price views are modified by news affecting the volume of supply and demand across the month. In late June, the weather outlook for at least the first half of July was for hot weather and associated increased demand.

We observed an increase in outage declarations of approximately 600 MW from mid-March to the beginning of June. Gas-fired units, at approximately 400 MW, were the largest contributors to this increase, followed by hydro units, at approximately 200 MW. Over this period, July forward prices rose steadily to $70/MWh. At this point, there was a downward correction in gas outage levels by approximately 300 MW, which was followed shortly thereafter by a reduction in July's forward price by approximately $10/MWh. After this point, total outages climbed once more to 1,400 MWs which was followed by an increase in price to $98/MWh. While these total outages and price observations do not move in perfect lock-step, there appears to be a moderate degree of correlation. Some participants may also have been uncertain about the timely return of a major gas generator from an outage.

Average expected intertie available transfer capability (system import availability) for July ranged from 762 MW to 817 MW, with expected availability at the lower level until the beginning of June. At this point, expected availability rose to the higher level and then slowly declined until the end of the month. These relatively modest changes in expected intertie availability do not seem to explain the increase in July forward prices.



Despite forward price increases in the latter half of Q2, July pool prices averaged $23.15/MWh. The MSA is assessing the relationship between the observed offer behaviour in the spot market and outcomes, competition and liquidity in the forward market.

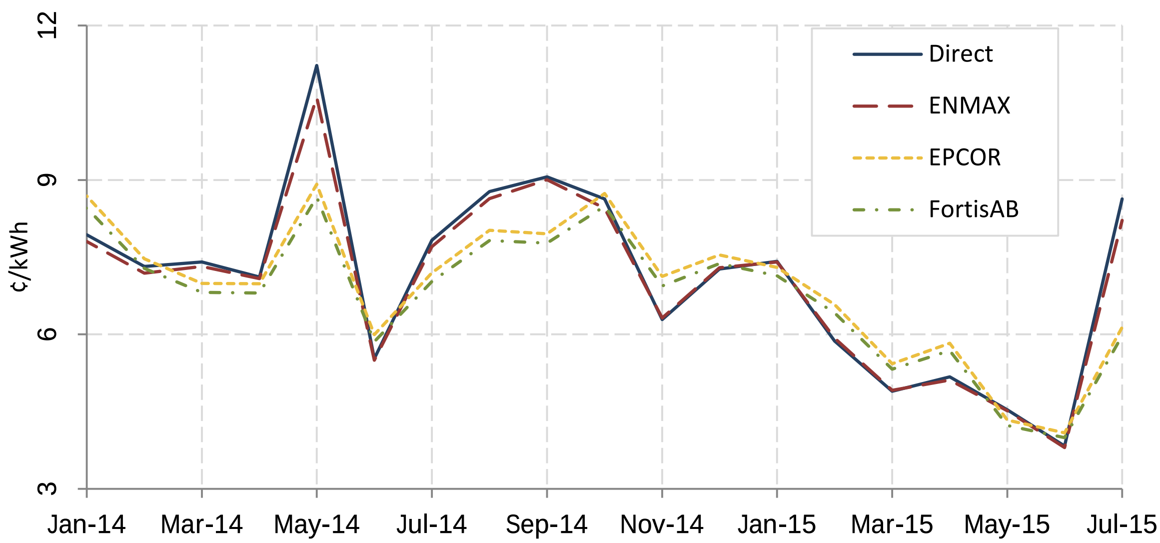
Retail

Annual baseline assessment of choice in Canada and the United States (ABACCUS) 2015

The ABACCUS report for 2015 was published on July 29, 2015 by the management consulting firm DEFG.[6] This series of reports has been published for several years and reports on the general development of retail electricity markets across North America. As has been the case for several years now, Alberta ranks very well in the report. In the residential sector Alberta ranks 2nd of 18 jurisdictions, with Texas being ranked the highest. For commercial and industrial customers Alberta ranked 4th of 18, down from 3rd last year.

Regulated retail rates

Throughout Q2/15 RRO rates were exceptionally low in response to the low wholesale market forward prices. The figure below shows the RRO rates of the four main providers since January 2014. June's RRO rates were the lowest in more than 10 years. However, July saw an uptick as forward market prices anticipated a tighter month.



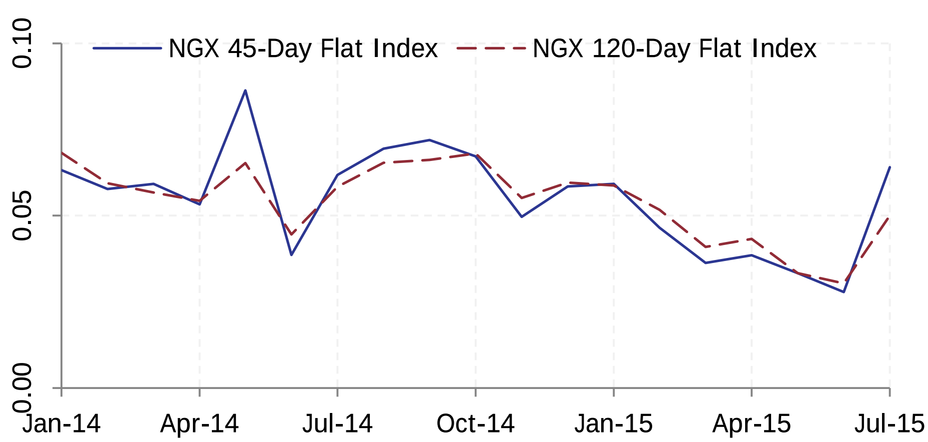
Also noteworthy in the figure is the fact that the clustering of the rates is not as close as it was in the past. Most of this can be attributed to the fact that EPCOR is procuring energy for Edmonton and Fortis customers using the full 120 day window allowed in the *Regulated Rate Option Regulation*. ENMAX and Direct are using the 45 day window allowed under the previous version of the regulation as they do not have the necessary approval from the Alberta Utilities Commission to use the 120 day window. Note that the 45 day window lies within the 120 day window and thus the firms are not operating offside the regulation. The mean, standard deviation and coefficient of variation of the data are shown below. On average the

[6] http://defgllc.com/

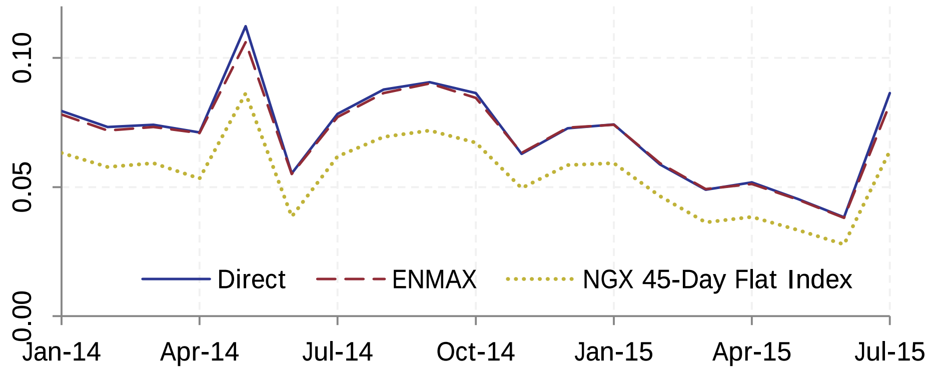
prices are the same across the providers. However, the volatility of prices measured by standard deviation or coefficient of variation show less volatility for those customers served by EPCOR. This lowering of volatility was one of the reasons for moving to a 120 day procurement window.

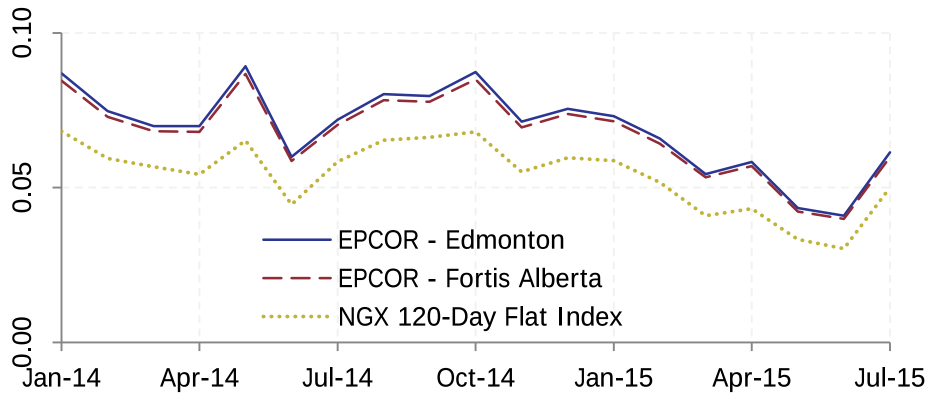
	Direct	ENMAX	EPCOR - Edmonton	EPCOR – Fortis (Alberta)
Mean (Cents/kWh)	7.1	7.0	6.9	6.7
Standard Deviation (Cents/kWh)	1.8	1.7	1.3	1.3
Coefficient of Variation (%)	25	24	19	19

The RRO rates are driven primarily by the cost of procuring energy in the forward market. These prices have been low in recent times due to an excess of supply over demand. The monthly NGX Index prices provide a useful indication of the prices being weighted average prices of trades over the relevant window. These are shown in the figure below.



While the two indices are often very similar, some months show divergence. These occur when the price for given contract month changes appreciably over the period when the companies are buying for the RRO customers. When we look at the NGX Index against the relevant RRO prices the patterns are very similar as would be expected:


0.00
0.05
0.10
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
Jul-15
Direct
ENMAX
NGX 45-Day Flat Index


0.00
0.05
0.10
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
Jul-15
EPCOR - Edmonton
EPCOR - Fortis Alberta
NGX 120-Day Flat Index

Operating reserves

Operating reserve costs nearly doubled in Q2/15 compared to Q2 of the previous year, an increase at least partially explained by the higher average pool price.

As mentioned earlier in the report, the cost of standby activations for spinning and supplemental reserve both averaged over $200/MWh. Overall, the cost of standby activations increased from under a million dollars last year, to over eleven million in Q2/15, as significantly more volume was activated at higher prices.

All active reserves are indexed to pool price which removes the pool price risk for sellers. The price for activating standby is not indexed to pool price. Sellers select fixed premium and activation prices which are combined by the AESO into a single value for ranking purposes. This means that sellers of standby reserves face a risk in choosing their activation price. If market conditions are expected to be tight, sellers will offer a higher activation price to better reflect the opportunity cost of being withdrawn from the energy market and into operating reserves. The MSA is not aware of any reasons why this design would be preferable to an activation price indexed to pool price. In many cases, this design appears to lead to inefficient outcomes.

Total Cost of Operating Reserves ($ Millions)

	Q2 2014	Q2 2015	*Change*
Active Procured	**33.9**	**58.6**	*+72.8%*
RR	8.4	16.0	*+89.6%*
SR	14.8	23.6	*+59.9%*
SUP	10.8	19.1	*+77.2%*
Standby Activated	**0.7**	**11.1**	*+1528.6%*
RR	0.2	0.1	*-26.9%*
SR	0.4	7.5	*+1700.6%*
SUP	0.1	3.6	*+3374.2%*
Standby Premiums	**3.6**	**5.9**	*+63.1%*
RR	1.4	2.0	*+48.6%*
SR	1.7	2.9	*+68.5%*
SUP	0.5	1.0	*+81.6%*
TOTAL	**38.2**	**75.7**	***+97.9%***

Total Volume of Operating Reserves (GWh)

	Q2 2014	Q2 2015	*Change*
Active Procured	**1463.6**	**1279.5**	*-12.6%*
RR	**340.5**	**340.2**	*-0.1%*
SR	**561.8**	**469.5**	*-16.4%*
SUP	**561.3**	**469.8**	*-16.3%*
Standby Activated	**18.1**	**50.4**	*+178.1%*
RR	**3.0**	**2.3**	*-22.8%*
SR	**11.3**	**33.0**	*+192.6%*
SUP	**3.8**	**15.1**	*+294.2%*
Standby Premiums	**532.8**	**548.8**	*+3.0%*
RR	**216.7**	**217.2**	*+0.2%*
SR	**228.2**	**241.5**	*+5.8%*
SUP	**87.9**	**90.1**	*+2.5%*

Average Operating Reserves Costs ($/MWh)

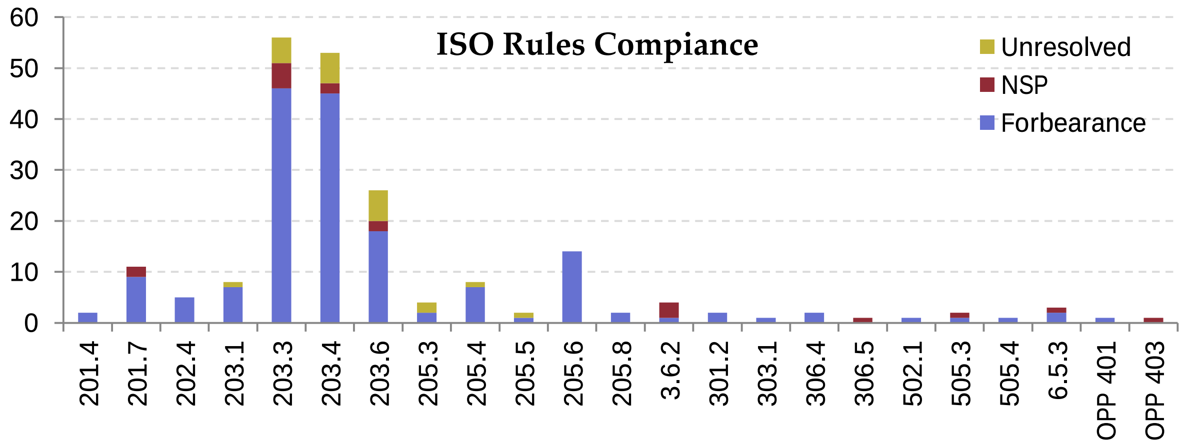
	Q2 2014	Q2 2015	*Change*
Active Procured	**23.18**	**45.81**	***+97.6%***
RR	24.73	46.93	*+89.8%*
SR	26.26	50.24	*+91.4%*
SUP	19.16	40.57	*+111.7%*
Standby Activated	**37.77**	**221.16**	***+485.6%***
RR	55.41	52.46	*-5.3%*
SR	36.73	226.04	*+515.3%*
SUP	26.85	236.61	*+781.3%*
Standby Premiums	**6.79**	**10.75**	***+58.3%***
RR	6.23	9.24	*+48.3%*
SR	7.54	12.01	*+59.2%*
SUP	6.22	11.02	*+77.2%*

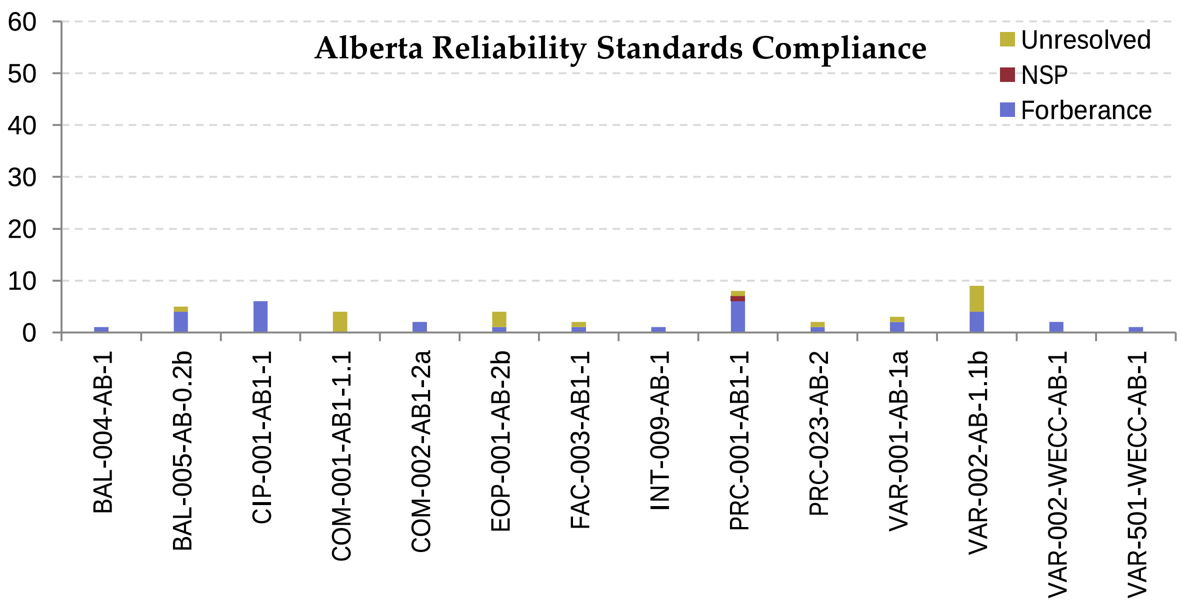
Compliance

In the first half of 2015, the MSA closed 188 ISO rules compliance files and issued 18 notices of specified penalty. The total financial amount of the notices of specified penalty was $16,750.

In relation to Alberta Reliability Standards compliance matters, the MSA closed 33 files in the first half of 2015. One notice of specified penalty was issued in Q1 2015 totaling $5,000. Two additional notices of specified penalty were issued in Q2 2015, however, these matters remained open as of the end of June pending payment or completion of ongoing mitigation plans.

Compared to the same period last year, the volume of Alberta Reliability Standards matters self-reported or referred year-to-date has decreased with these suspected contraventions distributed across a broader range of standards.





MSA activities and releases

- Market Share Offer Control 2015 (2015-06-30)
- MSA 2015 First Quarter Report (2015-05-29)
- Mergers and Acquisitions Workshop Notice (2015-04-30)
- Notice MSA Staff Changes (2015-04-30)
- Forbearance Letter re AESO Compliance per ISO Rule Section 501.10 (2015-04-09)
- Mandate and Roles Document (2015-04-09)
- Notice Revocation of Feedback (2015-04-07)

The Market Surveillance Administrator is an independent enforcement agency that protects and promotes the fair, efficient and openly competitive operation of Alberta's wholesale electricity markets and its retail electricity and natural gas markets. The MSA also works to ensure that market participants comply with the Alberta Reliability Standards and the Independent System Operator's rules.