Q2/14 Quarterly Report

April – June 2014

July 27, 2014

Wholesale market

The average pool price in Q2/14 was $42.43/MWh ($54.72/MWh on-peak, $17.85/MWh off-peak), which is 66% down from Q2/13 of $123.41/MWh. While average load (AIL) increased by over 200 MW in Q2, the pool price was $80.98 lower. This was as a result of on average 787 MW of increased supply cushion. The supply cushion increased in 2014 in part as a result of the return of SD1 and SD2 (560 MW) by November 2013 as well average generator outages across the period dropping by over 900MW. Higher supply cushion level usually leads to a lower pool price.

		2014	*2013*	*Change*
Avg. Pool Price ($/MWh)	*Apr.*	30.67	137.66	-78%
	May	54.05	127.66	-58%
	Jun	42.18	104.77	-60%
	Q2	42.43	123.41	-66%
Avg. Outage[1]e (MW)	*Apr.*	2773	3813	-27%
	May	2985	3826	-22%
	Jun.	3119	3939	-21%
	Q2	2959	3859	-23%
Avg. Supply Cushion (MW)	*Apr.*	2063	1179	75%
	May	2012	1375	46%
	Jun.	2116	1271	66%
	Q2	2063	1276	62%
Avg. Wind (MW)	*Apr.*	414	375	10%
	May	286	315	-9%
	Jun.	339	269	26%
	Q2	346	319	8%
Avg. Load (MW)	*Apr.*	8830	8632	2%
	May	8381	8126	3%
	Jun.	8456	8204	3%
	Q2	8554	8319	3%

April

The average price of $30.67/MWh in April was the lowest price in the last 6 years. Coincidentally this past April also had the highest average supply cushion at 2,063 MW and the highest average demand at 8,830 MW. Assuming an average heat rate of 10 GJ/MWh and an AECO-C (wholesale) natural gas price of $4.47/GJ in April, on average gas-fired generators sold below cost.

May

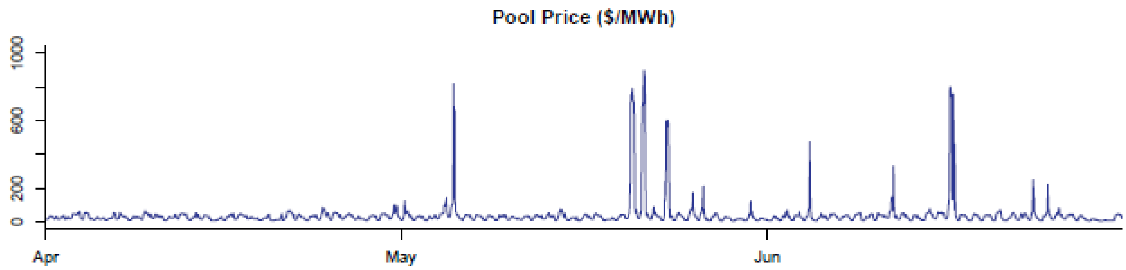
While forward prices for May indicated a tight month, in reality settled prices came in at close to half the forecasted price. For approximately the first half of May, the 1209L outage bottled generation in the Keephills-Ellerslie-Genesee (KEG) area causing, on average, over 400 MW of Constrained Down Generation (CDG). On May 5 price spiked to $818.15/MWh as a result of supply cushion dropping to 960 MW with 650 MW of CDG, no wind, and a reduced BC-AB ATC to 398 MW. In the third week of May a series of coal fired generator outages, at one point 4 major outages totalling over 1600 MW, caused price to spike to close to $900/MWh, the supply cushion fell to a low of 522 MW.

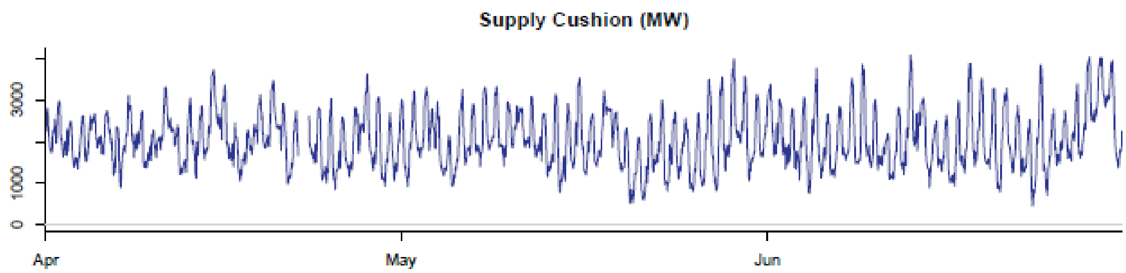
June

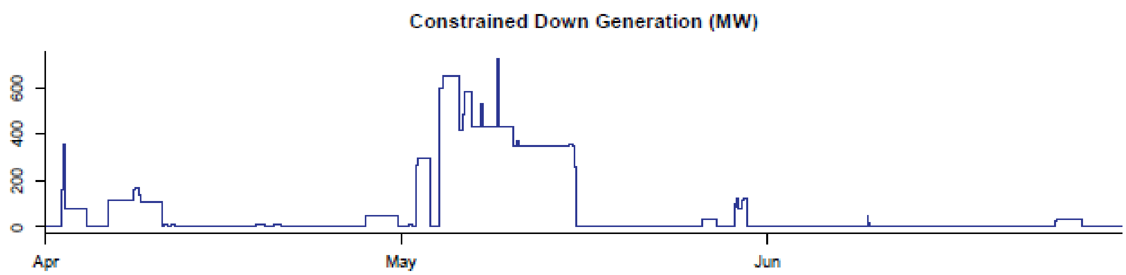
The average June price of $42.18/MWh is the second lowest in the last 6 years, with the highest average supply cushion at 2,116 MW and average load up over 800 MW across the 6 years.

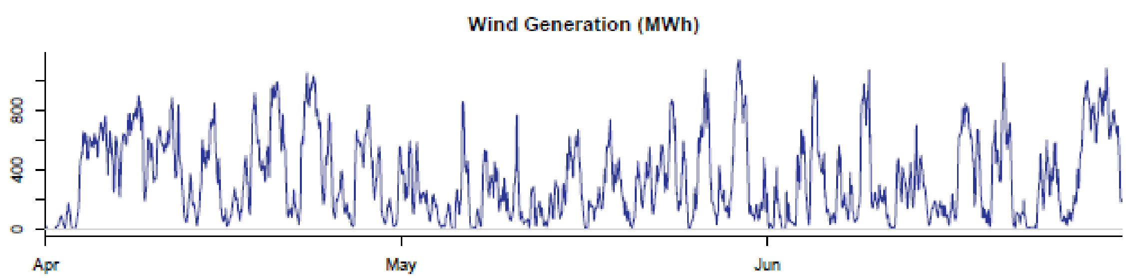
[1] Outage information in 2014 was normalized with 2013 data by removing a generator presently under construction.

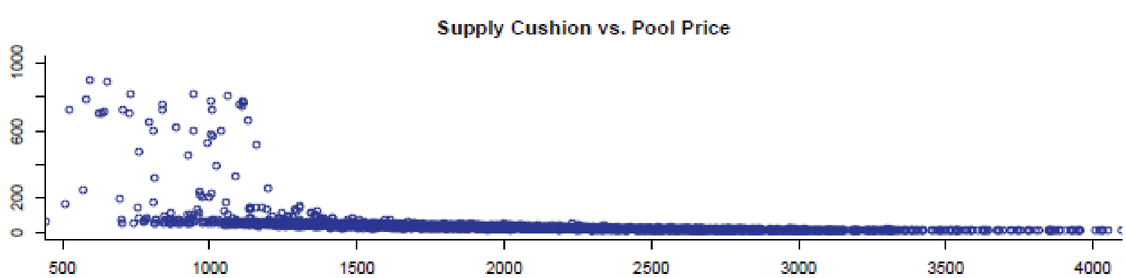
Prices spiked on June 16 to a high of $801.22/MWh with 4 coal fired generators on outage, a reduced BC-AB intertie capability and the Saskatchewan intertie (153 MW) on outage for the month of June. As a result the supply cushion fell to just over 1,000 MW.











Wholesale forwards

Trading activity

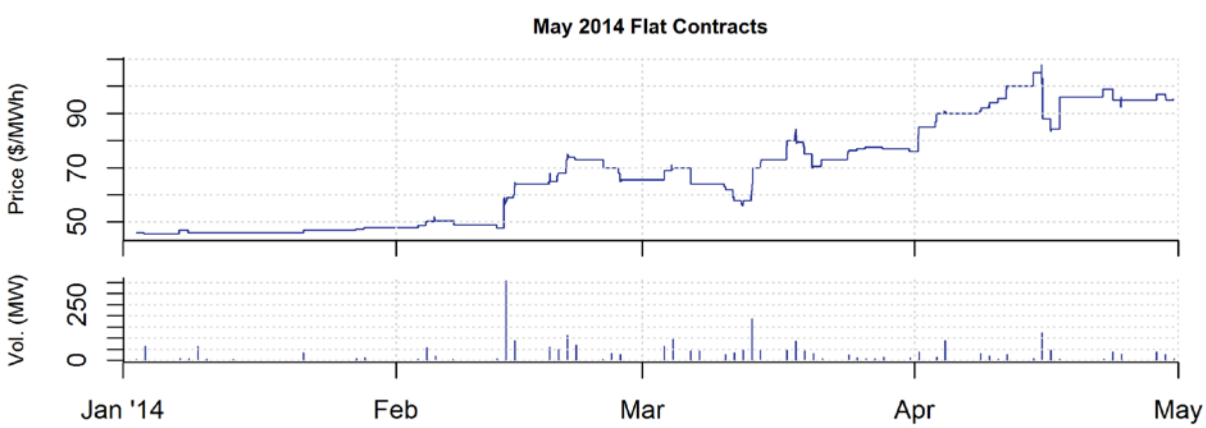
The first two months of Q2 experienced a drop in liquidity over the same period of the previous year, while liquidity in June improved. There was approximately 11.58 TWh of forward trades in the quarter, which was 13.8% lower overall than in Q2/14.

	TWh Traded		
	2014	2013	% Change
April	3.61	4.77	*-24.3%*
May	3.56	5.29	*-32.7%*
June	4.41	3.38	*+30.5%*
Q2	**11.58**	**13.44**	***-13.8%***

May forward contract

In the previous quarterly report we examined the uptick in the May forward contract. In this report we will go further to try explain the significant volume traded and price outcomes $30-40 $/MWh higher than April or June. The figure below sets out the closing price of the May 2014 flat contract and volume traded between December 1, 2013 and April 30, 2014.

Following a significant upturn in price in mid-February 2014 forward prices rose with the price peaking at $103/MWh on April 15, 2014. The average pool price for May turned out to be near half that amount at $54.05 /MWh



Forward market traders continually glean information, published by the market and others, for hints on changes in future supply and demand conditions which they then translate into a view of forward market price. Several of the reports the MSA assumes they review include:

- The AESO Daily and Monthly Outage Tables for potential generator outages that will impact supply
- The AESO Approved outages and Long Range Significant Transmission Outages reports that may increase congestion or interrupt supply.

- The AESO ATC Reports focussing on the forward looking Intertie Capability Report for interruptions in import or export capability caused by issues within Alberta
- The BCTC Transmission outage plan to discern if there may be interrupted or reduced supply from BC or in turn MATL
- Future prices in other markets to discern potential “off-shore” supply or demand to the Alberta market
- And whatever other reports available in helping create their view on the future.

Later on we illustrate how a letter to the AUC on a potential generation extension created a view of future market prices.

A number of participants began trading significant volumes of the May flat contract on the opening of the market on February 13, 2014. The price jumped $8/MWh on February 13, with 480 MW traded on the day, the highest single day trading of a product observed so far in 2014. The increase in the May flat contract coincided with the publication of a revision to the Long Term Critical Transmission Outages report by AESO at approximately 5 p.m. the previous day. The update included the announcement of a 12 day outage during May 2014 of the 500kV 1209L transmission line between the Genesee and Ellerslie substations in the KEG area[2]. Previous outages of elements in the KEG cut plane have seen curtailment of Alberta-BC imports and corresponding high spot prices.[3] May forward prices rose over the next few days as the market began to integrate the possibility of a limited intertie tightening supply and reducing competition in Alberta in combination with over 700 MW of coal outage for the first half of May.

The AESO had previously published via its Daily Outage Table that 720 MW of coal outage was expected out from May 3, 2014 through May 16, 2014, equivalent to two coal units on outage. For the remainder of May it appeared that 370 MW, equivalent to one coal unit, was on outage.

What not all of the trading community understood on February 13 was that the AESO followed its established procedure for coordinating outages and managing maintenance on the system. To minimise the impact of the 1209L outage AESO had co-ordinated this transmission outage with an already published generator outage. Synchronising these outages to the extent possible would help alleviate some of the potential “Constrained Down Generation” impact and its resultant impact on pool price. Some of the trading community did understand, as the owners or operators of generation (on outage) in the congested area purchased May forward contracts after the 1209L announcement, likely in anticipation of a run-up in prices. With the present

[2] KEG Limits described in AESO 2103-004R
http://www.aeso.ca/downloads/2013-004R_Keephills_Ellerslie_Genesee_Area_(TCM).pdf
[3] The CDG report provides a detailed analysis, see http://albertamsa.ca/uploads/pdf/Archive/00-2014/Q4_2013%20140131%20Final.pdf

publishing of only generator outage in aggregation by fuel type rather than unit names the generator owner and buyer of a unit in such situations, in the case of PPA units, have an advantage, especially when it comes to impacts caused in tandem with transmission outages which tend to be generator specific rather than simply impacting the supply cushion.

On February 26th the coal outages changed from 760 MW to 420 MW , effectively two units out of service (O/S) going to 1 unit O/S, for the period from May 3rd through May 16th prices responded by dropping from $70 to $65.

On March 3rd, a coal outage was scheduled by a market participant from May 10th 2014 through to June 16th, the outage tables then reflecting 770 MW O/S. Prices responded to this increase in outages moving up from $66 to $70. As reported in the previous quarterly report, this outage, less than 160 MW, was significantly overstated due to its normalisation as a 350 MW generator.

On April 16th a coal outage was cancelled, the outage tables now reflected 410 MW O/S, the forward price dropped from $103 on April 15th to a low of $83.50. This was a small generator normalised in the outage records as a 350 MW generator.

While the market surmised a tight month based on the combination of the 1209L transmission outage congesting both transmission and the interties and the expected coal outages the reality was different. While there is no indication that there was any untoward behaviour in the event, this is an example of how forward prices move in response to news affecting the supply-demand balance. In this particular instance it would appear that the published information led to an over estimate of the impact of transmission constraints and outages on the May price.

Incorrect outage data, May 1st, 2014

In the evening of April 30th ENMAX updated a large amount of outage data for its Shepard generators. Some of the entered information was incorrect. This included outage volumes from May 8th through June 8th, 2014 as well as some off-peak hours in July through December 2014. At the request of ENMAX the errors were communicated to the market in the morning of May 1st both via the AESO AIES Log as well as two notices to market participants.[4, 5]

> At 09:36 on May 1st the AESO alerted the market via the AIES event log that *"The AESO is aware an error exists in the generator outage information which was updated overnight, As a result the information contained in the outage reports may be incorrect"*.
>
> AT 17:39 on May 1st the AESO reported *"The generator outage information has been correctly updated and is reflected in the AESOs reports."*

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[4] AESO Notice to market participants May 1st, 2014
http://www.aeso.ca/downloads/ACSubmissions_NoticetoMarket.pdf
[5] http://www.aeso.ca/downloads/ACSubmissions_Notice2toMarket_05012014.pdf

The forward market typically trades between 7 a.m. and 1 p.m. on the NGX. While the outage data was entered after the forward market had closed on April 30th, it was roughly two and half hours after the market opened on May 1st that the market was alerted to a possible error in the outage records.

We have reviewed the actions of ENMAX and we are satisfied that they did not knowingly trade on the incorrect data. The quick response to recognise and correct the errors by the participant and the alert notices by the AESO helped to minimise the impact on the forward market.

All three interties are constrained off, May 21st 2014

On May 21st, the market observed a condition where all three interties were effectively reduced to 0 MWs of imports across several hours. At the time the importers were attempting to maximize their import as a result of high prices in Alberta which peaked at $897.21/MWh in HE 13.

936L and 937L (240 KV) are the two major transmission lines bringing power from the Langdon Transformer station into the Janet Transformer station just south of Calgary. Power coming into Langdon originates from wind in the southern portion of the province, imported power from BC and MATL as well as a portion of the imported power from Saskatchewan.

On May 21st, 936L was out of service. With 936L out of service, the AESO has to watch for overloading of 937L (Langdon to Janet) on the next contingency. On the loss of the most severe single contingency (MSSC) to make up the short-fall, there is an immediate in-rush of energy from the BC and MATL ties both of which feed into Langdon. When the AESO contingency analysis shows that the 937L emergency rating will be exceeded upon the loss of the MSSC, the AESO will pro-actively re-position the system to mitigate the next contingency overload. As the BC tie feeds directly into Langdon, it is more effective than MATL at solving the contingency. As a result, the BC tie line would be the first reduced and then the MATL if further action was required.[6]

On this particular day the overload condition was exacerbated by the outage to 9L20. 9L20 is a transmission line feeding the central east generation (over 1,400 MW of coal-fired generation and wind) towards Red Deer and ultimately in the load centers of Edmonton or Calgary. With this line out of service the Central east generation had to either flow south and west into Langdon and the Calgary load center via the 240 kV system or north toward Vegreville and the Cold Lake area on the 138 kV system – the majority goes to Langdon adding to the 937L flow

With the increased flow and in order to respect the next contingency it was necessary for the AESO to ultimately reduce, BC, MATL, and eventually the Saskatchewan intertie to 0 MW.

[6] Rule 302.1 TCM in addressing this issue.

Early in the morning of May 21st, the coal -fired generators went to full output. With the outage to 9L20 more MW's were now flowing into the congested zone ultimately increasing the reduction of imports across the three interties.

The congestion in the zone leading into 937L (Langdon to Janet) was as a result of the combination of 936L and 9L20 creating a condition in which there was more generation and imports than could be transferred across the 937L line. In such cases as per Rule 302.1 the first cuts are made to imports which are classed as an "opportunity" service and then internally to generation on a pro-rata basis.

The MSA does not believe that generators in the area either caused or exacerbated the congestion. This was simply a case of generation in a congested area competing to maximize their output in response to high pool prices.

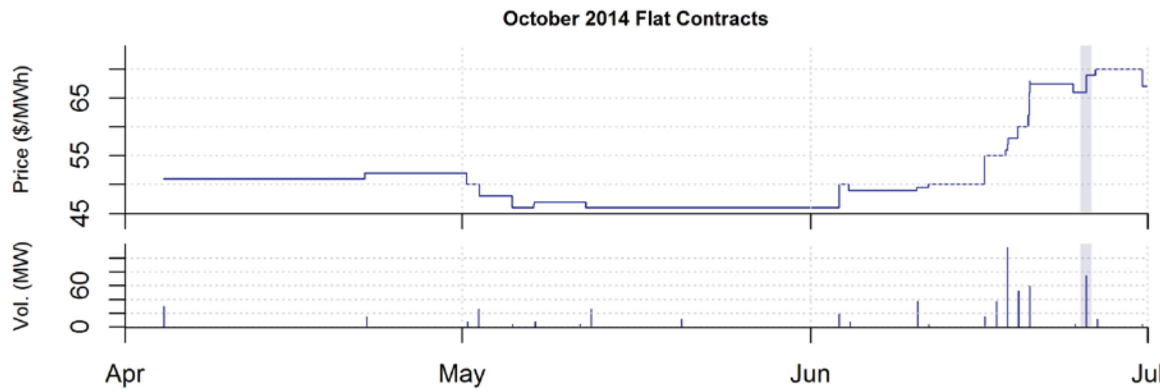
A notice to the AUC spurs the forward market, June 25th 2014

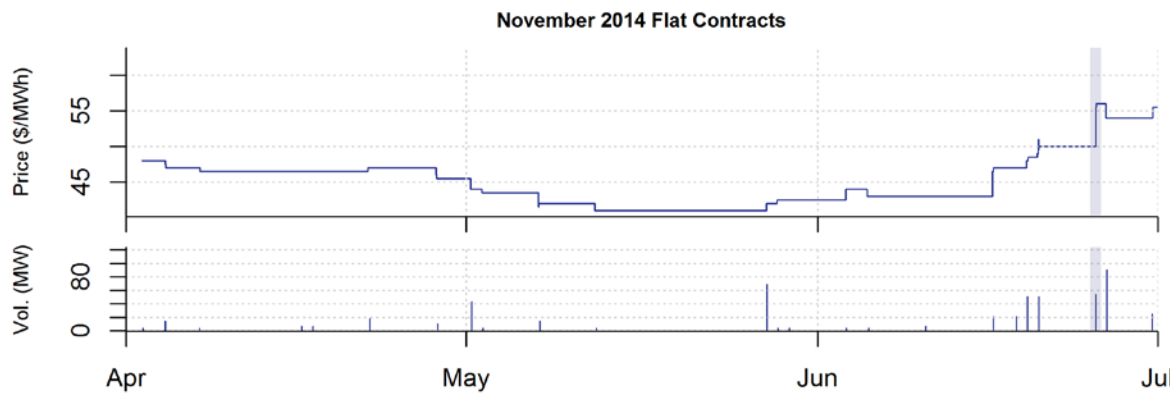
On June 24th ENMAX provided an update letter to the AUC on its Shepard Energy Centre[7]. We understand the objective of the letter was to give reasonable notice of a request for extension from December 31st, 2014 to June 30th, 2015 which might be required given recent contingencies at the site.

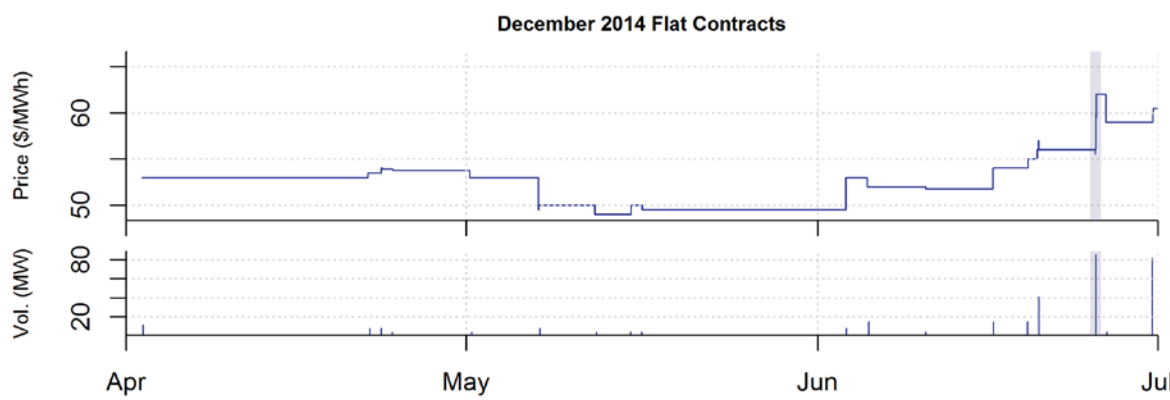
We infer from the trading records that the forward market reacted to this news. Provided below, are figures highlighting both price movements and volumes traded, with June 25th highlighted. Upon observing market activity, ENMAX wrote a second letter to the Commission[8] to clarify that that expected output values were likely to be updated, through ETS, numerous times throughout the commissioning process. ENMAX's second letter provided clarification to minimize the potential for misunderstanding by market participants about the Shepard completion date. This updated information would have influenced trades on June 26th.

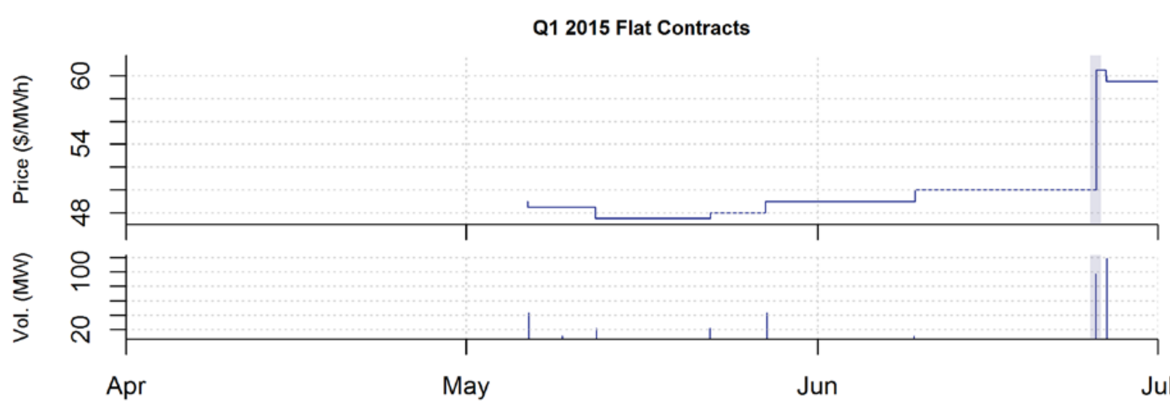
[7] ENMAX Letter to the AUC of June 24, 2014
https://www.auc.ab.ca/eub/dds/EPS_Query/ApplicationDetails.aspx?AppNumber=1610685&ProceedingId=3306

[8] ENMAX letter to the AUC of June 25, 2014
https://www.auc.ab.ca/eub/dds/EPS_Query/ProceedingSubmissionSearch.aspx?ProceedingId=3306


October 2014 Flat Contracts
Price ($/MWh)
45
55
65
Vol. (MW)
0
60
Apr
May
Jun
Jul


November 2014 Flat Contracts
Price ($/MWh)
45
55
Vol. (MW)
0
80
Apr
May
Jun
Jul


December 2014 Flat Contracts
Price ($/MWh)
50
60
Vol. (MW)
20
80
Apr
May
Jun
Jul


Q1 2015 Flat Contracts
Price ($/MWh)
48
54
60
Vol. (MW)
20
100
Apr
May
Jun
Jul

FEOC concern caused by AESO IT

The MSA was contacted by the AESO due to a potential FEOC issue caused by a limitation of their IT systems. For a period of 10 days it was possible for the asset owner of a generator to see the previous asset owner's generator offers.

In late December 2013 while transferring asset ownership of two generators the AESO discovered that upon the transfer, the "new" owner of the units would be able to see the (P, Q) pairs for these particular generators offered by the previous owner for the preceding 10 days.

While the AESO investigated various options to ensure the offers could not be seen it was determined that any short term solution could not be implemented without jeopardizing the integrity of the market data. The AESO has indicated to the MSA that they have added this issue to their Market Systems Replacement Project with a fix likely expected in 2016.

The MSA has reviewed the issue and while any ability to see other generators offers is a FEOC concern, in this particular instance it would appear that this is a very rare occurrence only when generators change ownership.

We have reviewed the data and found no untoward instances caused by this data breach. The MSA would like to advise that until the AESO tools are fixed, if there are transfers of ownership, participants are expected to take precautions to ensure FEOC compliance.

Preferential sharing of records

In the first quarter of 2014 the AUC had eight proceedings[9] related to applications seeking orders permitting the preferential sharing of records not available to the public, filed pursuant to section 3 of the FEOC Regulation. Further to section 3 of FEOC, the MSA may choose to participate in preferential information sharing proceedings. To date, the MSA has chosen to participate in all such proceedings. In the process, the MSA has observed some issues that can delay application approvals. In an effort to reduce issues associated with these applications and thereby expedite the process, the MSA provides the following suggestions to future applicants:

1. When drafting a preferential sharing application, applicants should ensure that each of the AUC's Minimum Filing Requirements for Preferential Sharing of Records Applications (available here) are met. Certain applications reviewed by the MSA have met the majority of the requirements, but omitted some sub points. The AUC has indicated in these proceedings that *all* requirements must be met; if they are not, information requests for the omitted information have generally been issued. This process delays the issuance of an order.

[9] Four of the proceedings have resulted in decisions from the Commission: 2014-030, 2014-075, 2014-117, and 2014-125.

2. The MSA must be notified of all preferential information sharing applications filed with the AUC, pursuant to section 3(4)(3) of the FEOC Regulation. The MSA requests that, in addition to a notification, the applicant also provide a copy of the application materials for the MSA's review. The MSA requests that notices are sent to the MSA Compliance mailbox – compliance@albertamsa.ca.

3. The parties must have an order permitting the sharing of preferential information from the first date any information is shared. If, for example, preferential information is to be shared during the testing phase of a new generation facility, the parties must ensure that the start date of the requested order covers this period.

The MSA also has a standing offer to talk to market participants intending to submit an application to the AUC under section 3 of the FEOC Regulation. In some cases market participants have found these discussions useful in determining whether the MSA would support or object to an application as filed and improving the clarity of their application. Market participants interested in discussing an application with the MSA should contact Mark Nesbitt by email at mark.nesbitt@albertamsa.ca.

Assessment of October 2013 changes to EPCOR's EPSP

Introduction

EPCOR's Energy Price Setting Plan (EPSP) uses an auction approach to procure energy for its Regulated Rate Option (RRO) customers. Beginning with delivery month October 2013 certain features of this approach changed. In particular, buying now takes place during a 120-day period preceding the delivery month (formerly 45 days) and the standardised block sizes are now 10 MW and 5 MW for flat and extended-peak contracts, respectively (formerly 25 MW and 10 MW, respectively).[10]

This section considers the effect of these changes on the performance of the auctions; particularly whether they resulted in greater auction market participation or lower / less volatile RRO prices for consumers.

Background

The Q3 2013 Quarterly Report contained an auction evaluation over the period July 2011 to June 2013. Among the conclusions were:

- neither EPCOR's auction prices nor its final RRO prices differed materially from those of ENMAX and Direct Energy;

- forward prices were generally a poor predictor of spot prices;

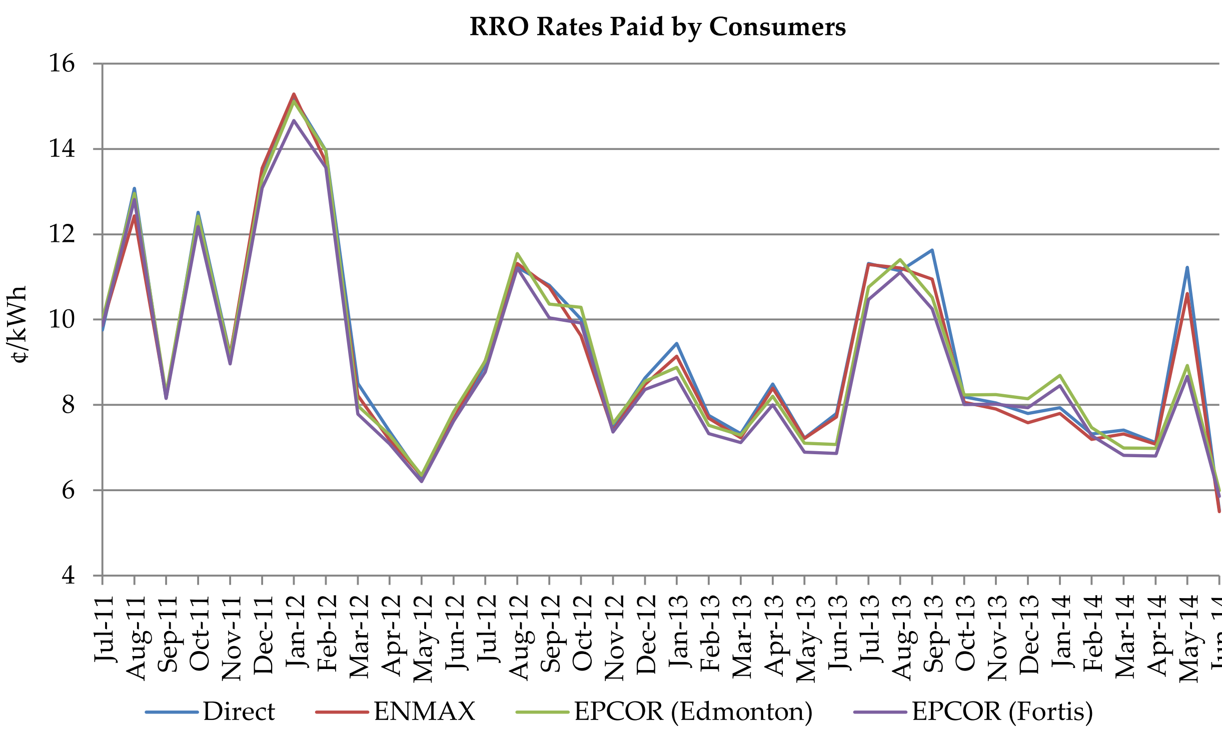
[10] A change to the RRO Regulation enabled use of the extended buying window. The change of block size was EPCOR-specific.

- the average number of sellers, blocks offered, blocks offered but not sold, and percentage price reduction per block (price reduction divided by final procurement price) fell somewhat; and,
- the average number of price reductions per block offered was stable.

Assessment of the extended buying window

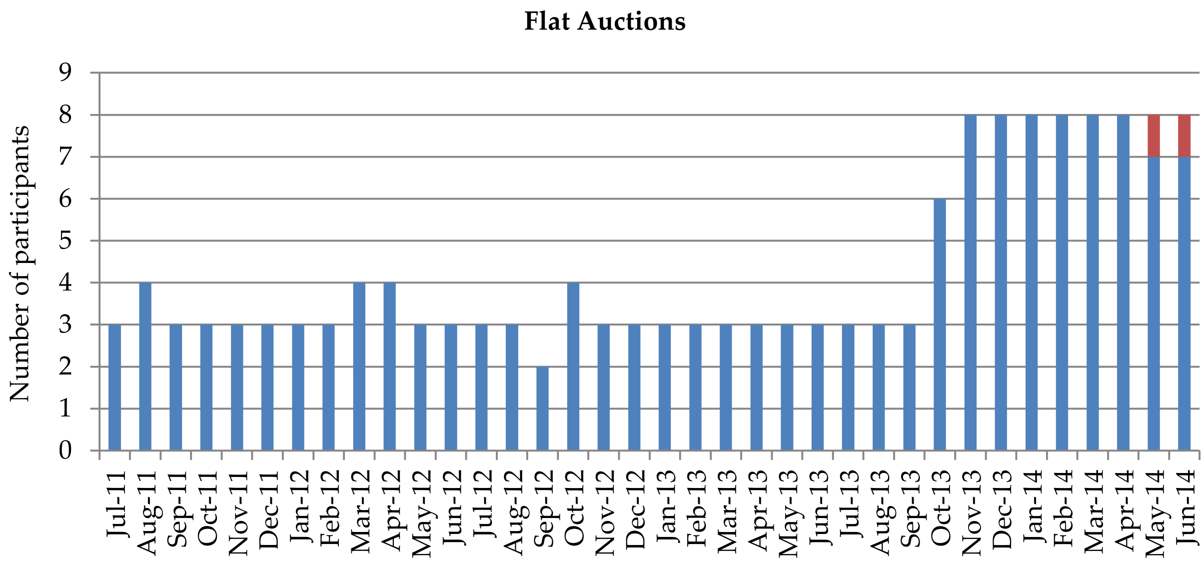
Buying over a 120-day period rather than a 45-day period means the energy component of the RRO price paid by consumers is a function of a larger set of forward prices. To the extent there are no systematic trends in forward prices for a given delivery month leading into that month, buying over a longer period of time would not be expected to impact the level of RRO prices paid by consumers compared to otherwise. If there is an upward trend to forward prices leading into the month, then buying over a longer period of time will result in a lower RRO price paid by consumers than buying over a shorter period because the early purchases lower the average. Conversely, if there is a downward trend to forward prices leading into the month, then buying over a longer period of time will result is a higher RRO price paid by consumers than otherwise.

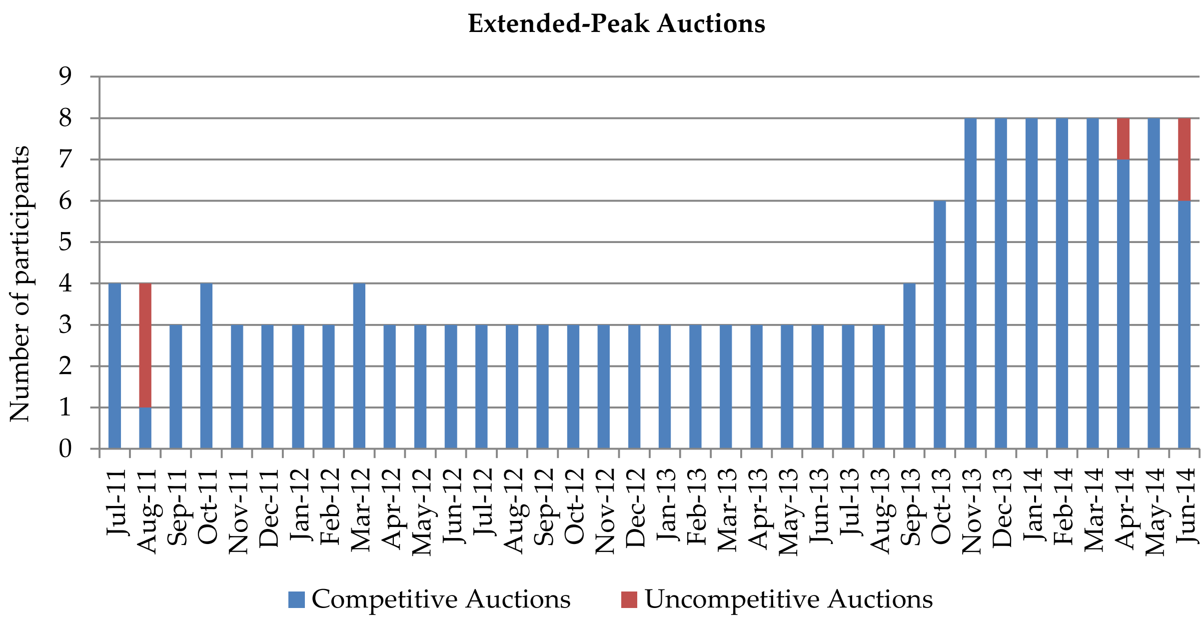
There have been 9 delivery months since the auction rules changed. As before the auction rule change, the RRO price paid by consumers does not vary systematically across the three largest providers: EPCOR, ENMAX, and Direct.



There are two months—January and May 2014—with a noticeable difference across EPSP of RRO prices paid by consumers. Flat forward prices related to May are illustrated above in the 'Wholesale forwards' section. For the reasons discussed there, a material upward trend of forward prices leading into the delivery month resulted in a noticeably lower RRO price for EPCOR consumers than ENMAX and Direct consumers because it had made purchases early at relatively low prices. The opposite pattern (not illustrated) of forward prices and RRO prices paid by consumers occurred in January 2014. As such, extension of the buying window can have both an increasing and decreasing effect on RRO prices paid by consumers. In the absence of systematic evidence of either an upward or downward trend of forward prices as the delivery month approaches, the directional effect of extending the buying window on RRO prices paid by consumers is unclear. In addition to the level of price, an extended buying window may reduce the volatility of RRO prices paid by consumers by spreading auction dates over a wider range of time. While plausible, there is insufficient data to consider this impact of this effect at this time.

EPCOR's EPSP auctions are held routinely by the Natural Gas Exchange (NGX). Based on confidential criteria, the NGX determines whether there are sufficiently many unique participants to consider the auction to be competitive or not. If there are too few participants the auction is cancelled (not held beyond the initial submission of offers). Otherwise, the auction proceeds. The figure below illustrates the number of auctions held in relation to a given delivery month and, of these, the number of which were deemed by the NGX to be competitive and uncompetitive.



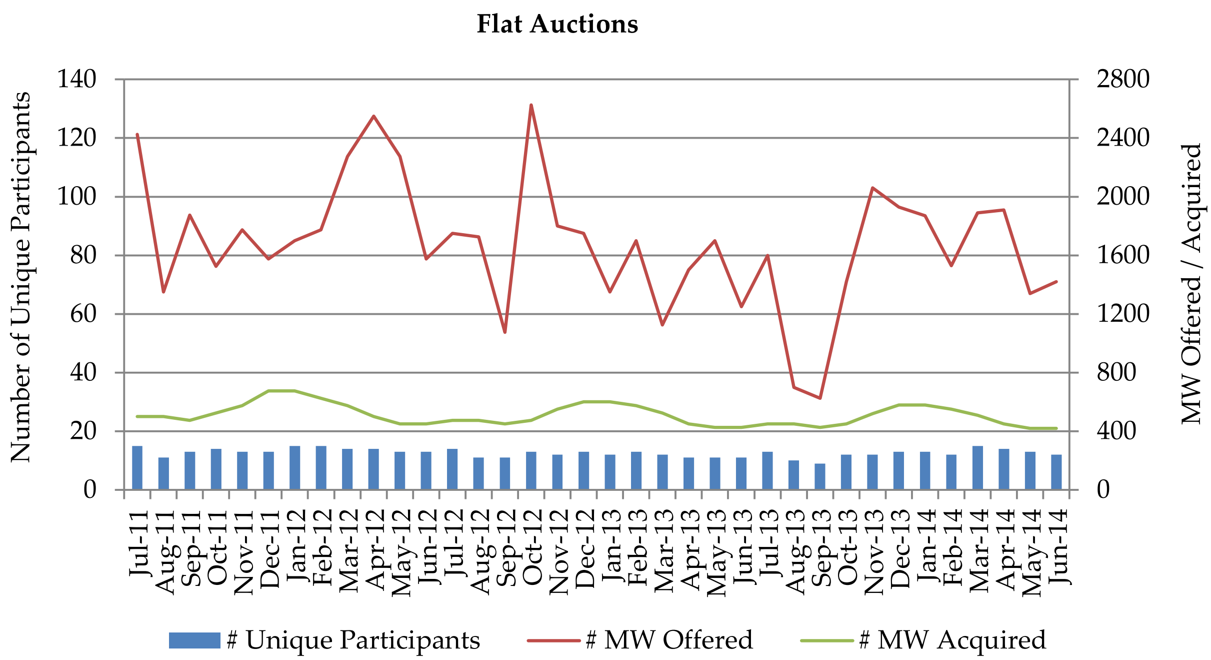


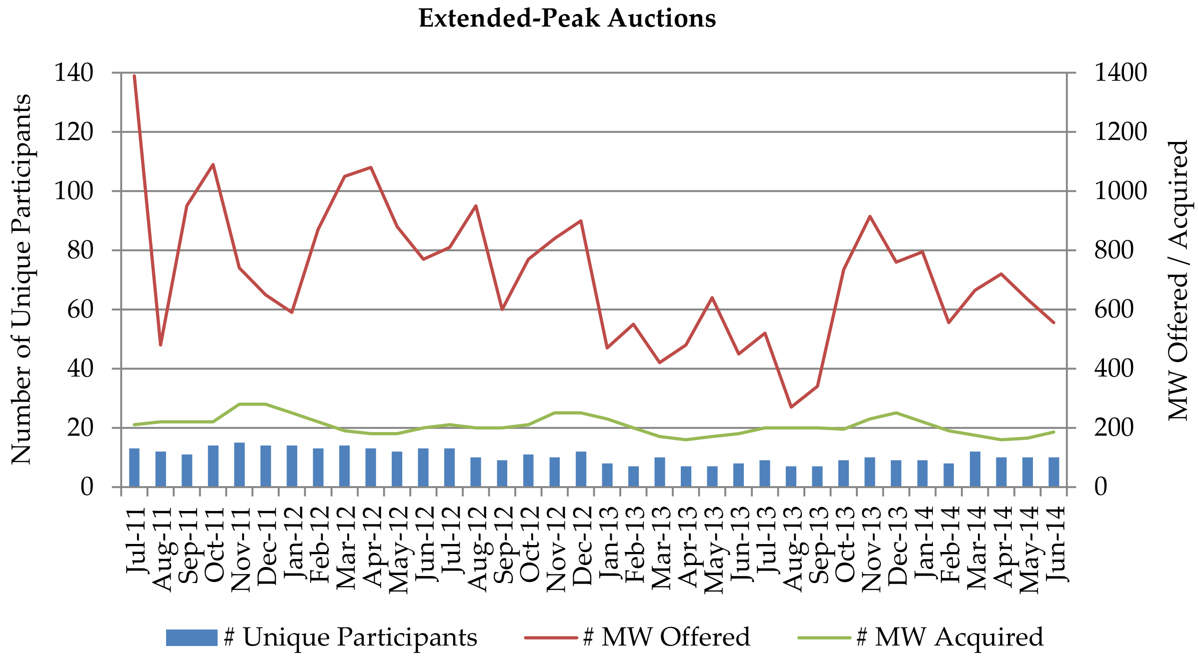
The most obvious feature of the figures above is the increase in the number of auctions associated with the changes to the EPSP buying window (and block size reduction) from approximately 3 before the change to 8 afterward. For the most part there is sufficient participation in the auctions for them to be deemed competitive. However, a few auctions—2 for flat contracts (out of a total of 154) and 6 for extended-peak contracts (out of a total of 152)—have been deemed uncompetitive. Aside from several August 2011 extended-peak auctions, all of these have occurred since the auction rule change.

The reasons for the observed increase, albeit relatively minor, of the frequency of auctions that are deemed uncompetitive are not clear. One possible reason for this is that with a greater number of auctions there will be less volume / fewer blocks procured in any individual auction, which may reduce the interest of offerors to offer in *each auction* (though, as will be discussed in the next section, the decrease of block size has arrested the decline of the number of participants that contest *any* auction for a given delivery month. Notwithstanding, the vast majority of auctions were deemed to be sufficiently competitive to proceed.

Assessment of the block-size change

Reducing the size of blocks required to be offered at auction means that any individual contract is a relatively smaller commitment for an offeror (and allows for more auctions to be held since more blocks are required to meet a given expected load profile). The two figures below illustrate the number of unique participants and the number of MW offered or acquired in the auctions related to each delivery month. As noted in the MSA's previous evaluation, the number of participants had fallen somewhat over the years preceding the auction rule change; this was especially true of extended peak auctions. The downward trend appears to have been arrested in the months following the rule change.





The MSA's previous evaluation also noted the number of blocks offered had fallen somewhat in the preceding years; this was especially true of extended peak auctions. A comparison of blocks offered must account for the change of block sizes; to that end, all offers are converted from blocks to MW. As with the number of participants, the downward trend appears to have been arrested in the months following the rule change.

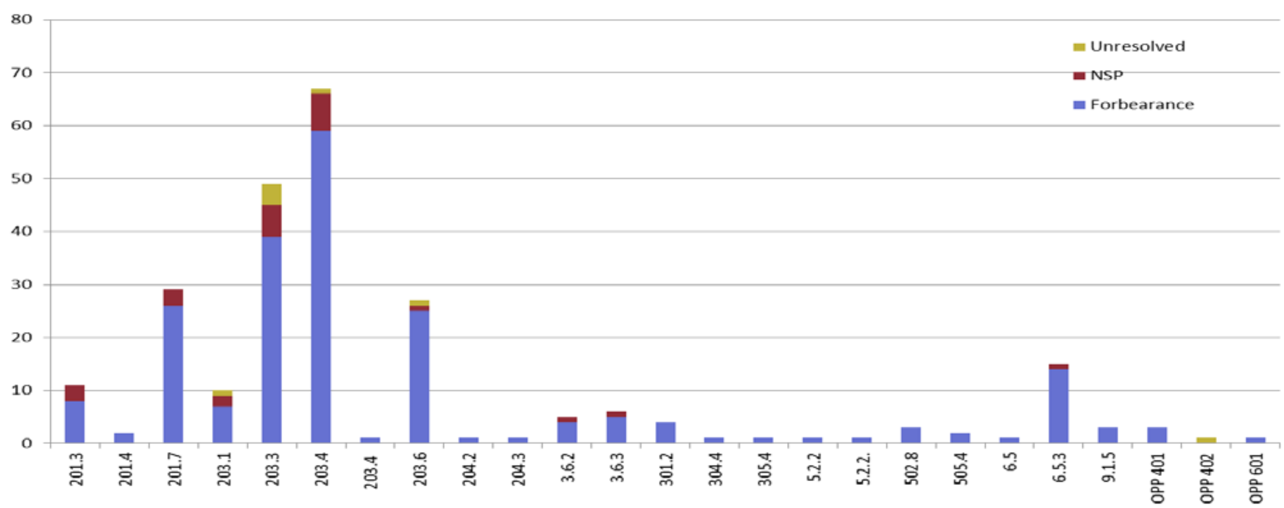
Rebidding (submitting a lower block price) in the auctions held by the NGX is relatively straightforward. However, it may be sufficiently labour intensive that an individual is not able to simultaneously control offers for more than a few blocks. This is because once the random close period is initiated rebidding to undercut an existing offer requires time that bidders may reasonably expect will not be available to them. To the extent that transaction costs of this nature are binding on bidders, the number of blocks an individual trader will be able to offer will be limited. The effect may be to require more individuals to manage a given participant's offers or reduce the quantity (in MW terms) of offers made. Either of these effects would serve to partially offset the benefits associated with the reduction of block sizes.

At this point in time there is insufficient data to draw a definitive conclusion about the net impact of the auction rule changes or modify the conclusions reported in the Q3 2013 quarterly report.

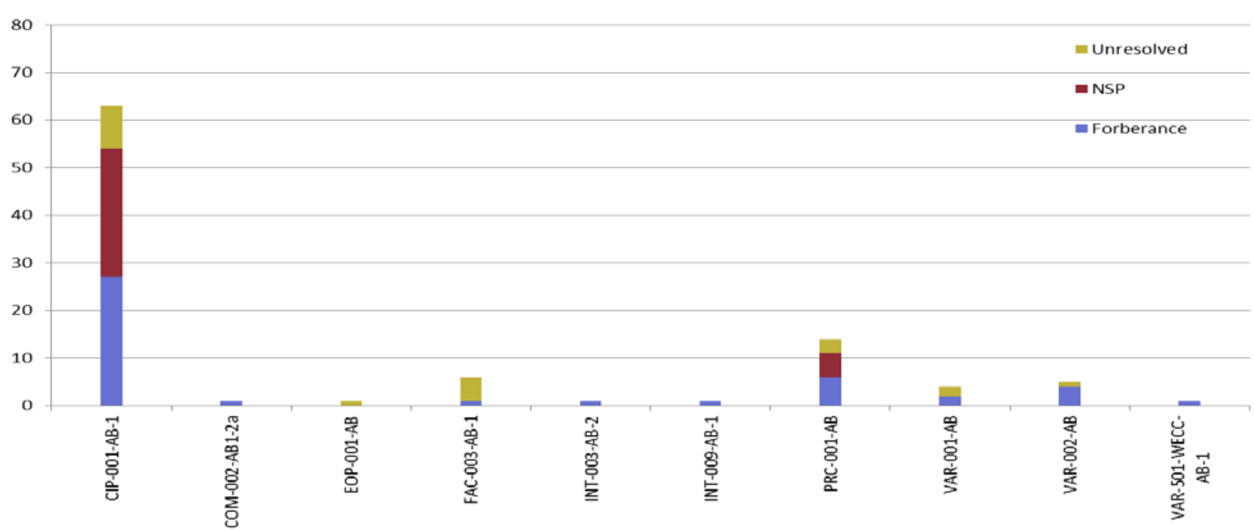
Compliance

- In relation to ISO rules compliance, the MSA issued 24 notices of specified penalty through the first half of 2014 for $24,500 in financial penalties.
- In relation to Alberta reliability standards compliance, the MSA issued 11 notices of specified penalty through the first half of 2014 for $77,500 in financial penalties. Two other specified penalties were issued regarding ARS files not considered closed as of the end of Q2/14.
- The volume of CIP-001 related matters in 1H/14 is a function of AESO compliance audit activities and the MSA's practice of tracking each referred standard requirement contravention separately.

ISO Rules Compliance, Q2 2014



Alberta Reliability Standards Compliance, Q2 2014



MSA activities and releases

Market reporting

MSA 2014 First Quarter Report (04/16/14)

Notice

Notice re Market Share Offer Control 2014 (07/07/14)

Notice re Employment Opportunity - Compliance Analyst (07/07/14)

Notice re Court of Appeal Proceedings (07/03/14)

Notice re Retail State of the Market Report - Advisory Group (06/12/14)

Notice re Supply Cushion Data (04/30/14)

Notice re Annual Retail Statistics Report (04/16/14)

MSA Staff Changes (04/04/14)

Other

Feedback - Sale of Genesee Strips (05/16/14)