Q3 / 13 Quarterly Report

July – Sept. 2013

Nov 20, 2013

Wholesale market

The average pool price in Q3/13 was $83.61/MWh ($115.02/MWh on-peak, $20.81/MWh off-peak), approximately 7.07% higher than in Q3/12.

Though the pool prices were roughly at the same level as last year, three weeks observed an average price greater than $100/MWh (see the three highlighted areas in the next charts). Excluding these three weeks the average pool price would be $45.31/MWh.

		2012	2013	*Change*
Avg. Pool Price ($/MWh)	Jul.	68.39	56.14	*-17.91%*
	Aug.	56.54	83.64	*47.93%*
	Sept.	110.39	111.98	*1.44%*
	Q3 Total	**78.09**	**83.61**	***7.07%***
Avg. Outages (MW)	Jul.	2718	3289	*21.01%*
	Aug.	3084	3325	*7.81%*
	Sept.	3655	3655	*0.00%*
	Q3 Total	**3147**	**3420**	***8.67%***
Avg. Imports and Exports (MW)	Jul.	570	291	*-48.95%*
	Aug.	403	265	*-34.24%*
	Sept	250	221	*-11.60%*
	Q3 Total	**409**	**259**	***-36.27%***
Avg. Supply Cushion (MW)	Jul.	2038	1291	*-36.65%*
	Aug.	1544	1346	*-12.82%*
	Sept.	1361	1329	*-2.35%*
	Q3 Total	**1651**	**1322**	***-19.93%***

The high pool prices were a result of a low supply cushion–the total amount of energy that was available but was not needed to be dispatched by the Alberta Electric System Operator (AESO). Factors that account for the low supply cushion include, among other things:

- Market demand: the peak load was more than 10000 MW on July 2.
- Planned and forced outages: the Keephills 1 (KH1), with a capacity of 395 MW, was out-of-service throughout the quarter.
- Imports / exports: the BC to AB tie line was unavailable due to a transmission outage in BC from Aug 26, 2013 HE 8 to Sept. 6, 2013 HE 19.
- Internal transmission congestion: constrained down generation (CDG) was a major factor on July 2, 2013 but not in other periods.

Finally, a change in offer price of several coal units offering their whole capacity at $0/MWh throughout the quarter (discussed below) influenced low pool prices during other weeks.

July

The first week of July was a week of feast and famine for Alberta where electricity prices bracketed both ends of the market. The week Monday, July 1, 2013 to Sunday, July 7, 2013 (see highlighted in the following charts) observed an average pool price at $121.97/MWh, a high price of $1000.00/MWh and a low price of $0/MWh. The high price was reached on July 2nd as the AESO declared an energy emergency and ultimately shed 200 MW of load and (discussed below, Emergency Alerts). The low price was reached on the early morning of July 7th when some imports were curtailed due to surplus power supply (briefly discussed below, Zero dollar offers of coal generation). In both cases the market would have failed to clear without action by the AESO.

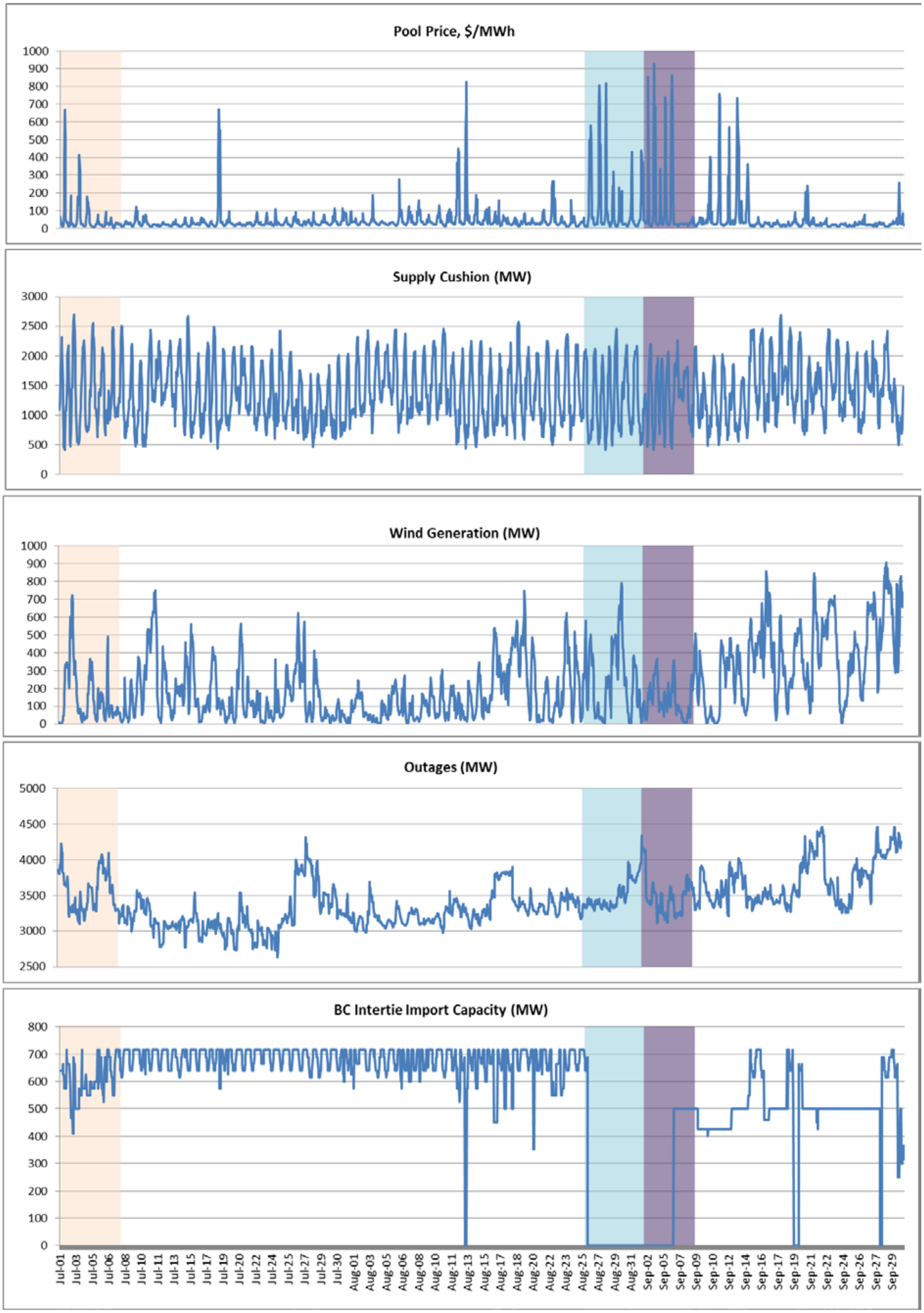
August

In the latter part of August a combination of generator outages and the BC-AB tie line tightened the supply cushion, leading to high prices. For the week Monday, August 26, 2013 to Sunday, September 1, 2013 (see highlighted in the next charts) pool price averaged $200.05/MWh. The high prices were a result of the outage of the BC intertie line, generator outages and low wind generation.

September

The first week of September was a continuation of the last week of August with a combination of generator outages (up to 3479 MW on outage) in concert with the BC-AB tie continuing out of service (0 MW of inter-tie capability). For the week Monday, Sept. 2, 2013 to Sunday, September 8, 2013 (see highlighted in the next charts) pool price averaged $317.31/MWh. The high prices were caused by a decline in average on-peak supply cushion to 695 MW. Low wind generation also contributed to the high price.

The following chart presents the hourly pool price, supply cushion, wind generation, generator outage and BC intertie import capacity from July 1 to Sept. 30, 2013.


Pool Price, $/MWh
Supply Cushion (MW)
Wind Generation (MW)
Outages (MW)
BC Intertie Import Capacity (MW)

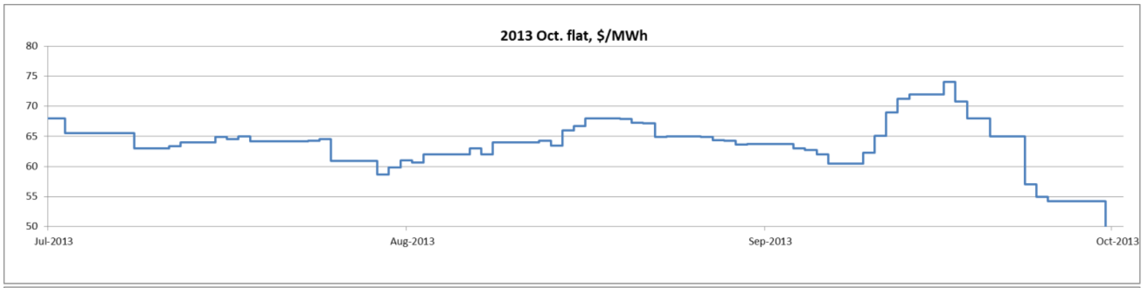
Wholesale forwards

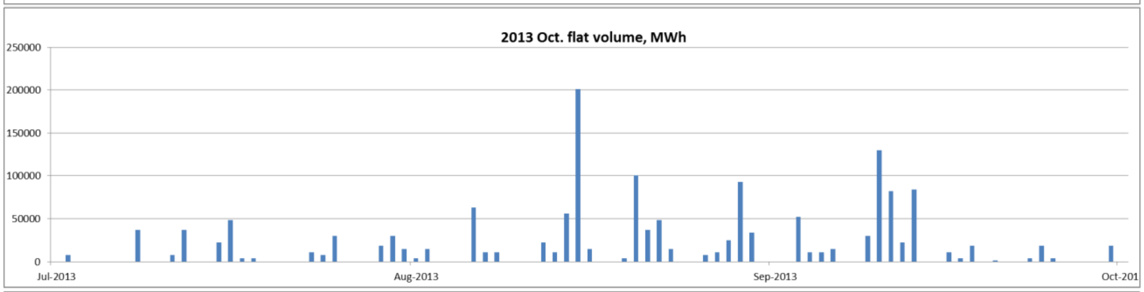
Trading activity

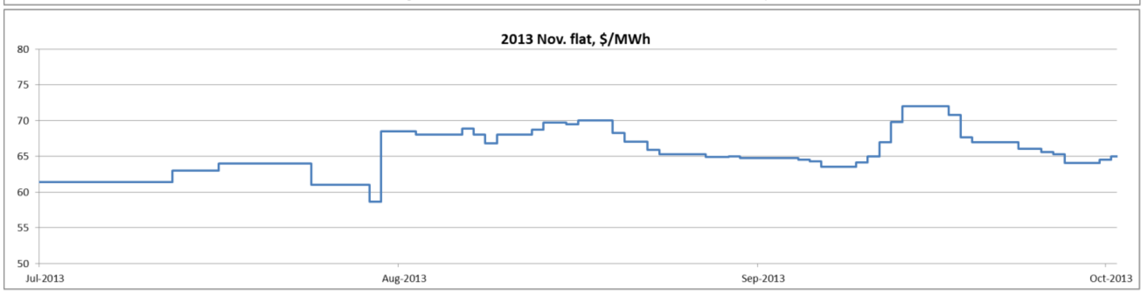
In Q3/13 there were approximately 10.22 TWh of forward trades, which is 13.46% lower than in Q3/12 and 26.69% less than in Q2/13. July and August saw increases in liquidity over the previous year, while September saw a substantial decline.

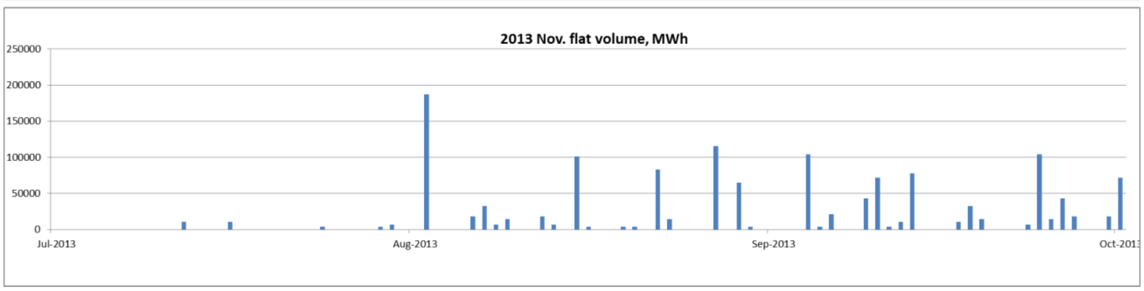
	TWh Traded		
	2012	2013	*% Change*
July	3.00	3.28	*9.33%*
August	2.95	3.62	*22.71%*
September	5.85	3.32	*-43.25%*
Q3 Total	**11.81**	**10.22**	**-13.46%**

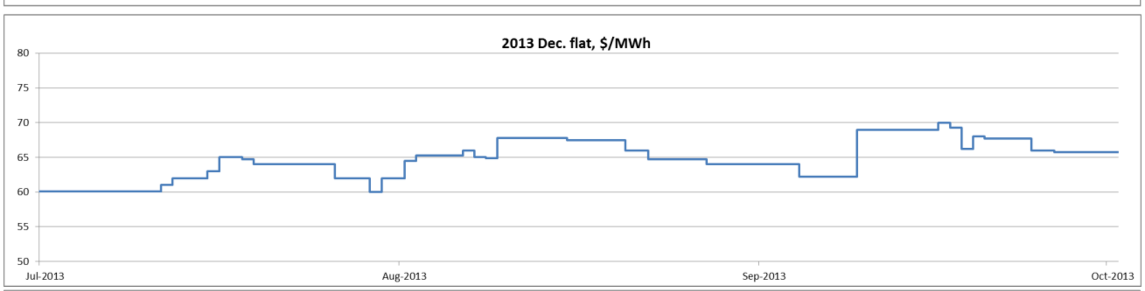
From September 11 to September 18, forward market prices for October and November 2013 flat contracts sharply increased. Subsequently the prices gradually dropped to the previous level. The data is summarized in a series of charts on the next page. The MSA reviewed the data but could not get a reasonable explanation for the rapid increase. The MSA would appreciate any assistance from market participants in understanding the phenomenon

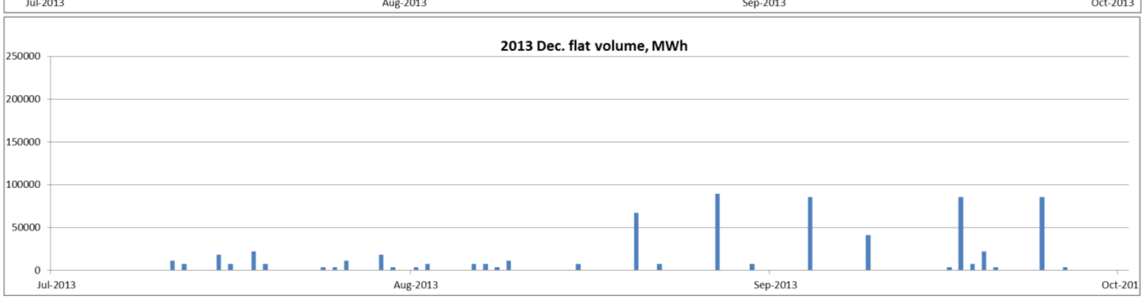

2013 Oct. flat, $/MWh
80
75
70
65
60
55
50
Jul-2013
Aug-2013
Sep-2013
Oct-2013


2013 Oct. flat volume, MWh
250000
200000
150000
100000
50000
0
Jul-2013
Aug-2013
Sep-2013


2013 Nov. flat, $/MWh
80
75
70
65
60
55
50
Jul-2013
Aug-2013
Sep-2013
Oct-2013


2013 Nov. flat volume, MWh
250000
200000
150000
100000
50000
0
Jul-2013
Aug-2013
Sep-2013


2013 Dec. flat, $/MWh
80
75
70
65
60
55
50
Jul-2013
Aug-2013
Sep-2013
Oct-2013


2013 Dec. flat volume, MWh
250000
200000
150000
100000
50000
0
Jul-2013
Aug-2013
Sep-2013

Energy Emergency Alerts - July 2, and September 3, 4, 5, 2013

The AESO has issued energy emergency alerts (EEA) several times in this quarter, and across a total of 8 days in 2013. An emergency alert means that all commercial options have been fully utilised to satisfy demand .[1] The price settles at the highest energy offer made in the market which is typically at $999.99/MWh. However, when the highest level of alert is declared, the price settles at the administrative level of $1000.00/MWh.

On July 2nd at 11:22 the AESO issued an EEA1 alert, the situation worsened as a result of the loss of a major transformer in the Edmonton area that automatically shut down at 14:05, causing the necessity to shed load. At one point over 800 MW of generation was constrained down due to the loss of this transformer and 200 MW of firm load had to be shed. The MSA reviewed this emergency event at the time and had no concerns with market behaviours or the implementation of the AESO emergency procedures. In all the emergency state lasted for 6 hours 42 minutes.

On September 3rd, 4th and 5th as a result of a series of generator outages combined with the outage of 1201L, the BC to AB inter-tie, the AESO implemented emergency procedures for a total of 13 hours and 48 minutes. No load was shed during these events.

The MSA reviewed the AESO's historical event log to determine the frequency of past energy emergency alerts. The table extracted from the AESO's historical event log shows there were more emergency hours in 2013 than in any previous year. The MSA would surmise that this was caused by the combination of forced and planned outages of both generation and transmission. In any event, AESO's recent Long Term Adequacy Metrics (August 2013) reported the forecasted reserve margin is about 20% in 2013. We flag the statistics in the table not as an issue of reliability but simply as part of the MSA's reporting whenever administrative action is substituted for market outcomes.

Energy Emergency Alert by Years			
Years	Days	Hours	*EEA3*
2013	8	39:11	1
2012	4	8:48	1
2011	7	11:36	0
2010	2	8:51	0
2009	3	5:24	0
2008	6	12:10	0

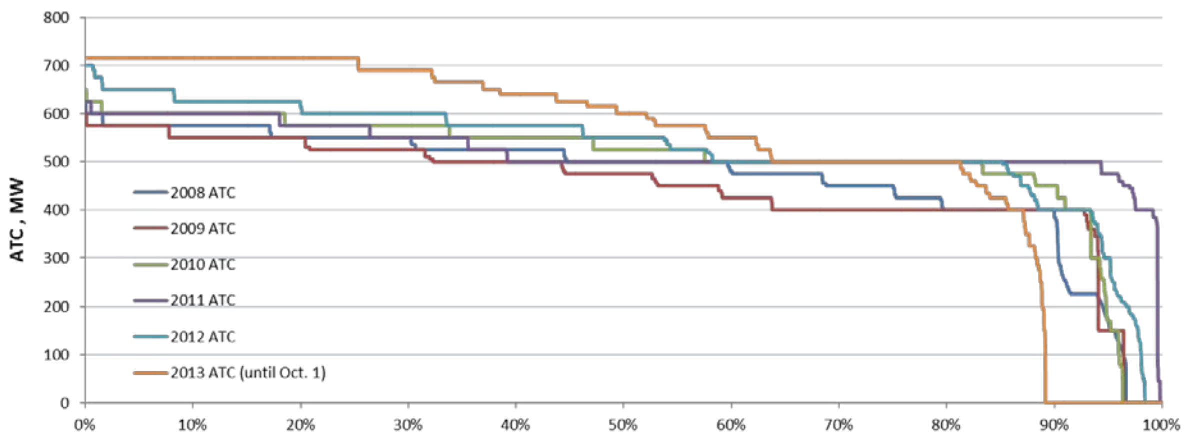
[1] ISO Rule 305.1 defines four levels of energy emergency alerts (EEA). An EEA1 is declared if the ISO has issued dispatches for all operating blocks in the energy market merit order, operating reserve requirements are being met and the ISO is concerned about sustaining its operating reserves. An EEA2 is declared if the ISO foresees, or has implemented procedures up to, but not including, the curtailment of firm load, such that operating reserves are committed to maintain balance of supply and demand ensuring that the regulating reserve margin is maintained. An EEA3 is declared if the ISO foresees or has implemented curtailment of firm load. An EEA0 is declared if an EEA1, EEA2 or EEA3 is terminated.

The Interties

The supply cushion in late August and early September tightened partially as a result of the outage to the BC to AB tie line that is currently capable of providing up to 715 MW of import capability.[2] As we noted above, price increased rapidly partially because of this lowering of the supply cushion as internal generators responded. This illustrates the importance of the interties to the competitive process in Alberta.

We decided to review to date how the interties have been operating with respect to previous years. The following is a duration curve of the available hourly import ATC, the portion of the transmission available to competitive process for importing power to Alberta. There is a portion above this referred to as the Transmission Reliability Margin (TRM), which is not available for the market but is simply there to enhance reliability.

Duration Curve of BC-AB Tie Line Import ATC by Year



From reviewing the figure for 2013 (from Jan. 1 to Oct. 1) in comparison to previous years it is clear in 2013 that ATC[3] across most of the year to date has increased, average ATC in 2013 to date is 539 MW, comparing to the best previous year of 528 MW. The on-peak ATC exhibited the same characteristics.

Examining the duration curve of ATC reveals that in 2013:

1. More than 20% of the time there is 715 MW available, which is better than any year in the past six years. 715 MW presently being the maximum ATC available based upon the AESO's reliability criteria.
2. More than 80% of the time there is greater than 500 MW of ATC available which is better than any year in the past six years. Upon review the large ledge at 500 MW is a reliability limit imposed due to one or more outages of a series of 11 - 240 KV North-South transmission lines

[2] The rated export capacity is 1200 MW.

[3] For details on ATC allocation, see http://www.aeso.ca/downloads/ID_2011-001R_Available_Transfer_Capability_and_Transfer_Path_Management.pdf

effectively between Edmonton and Calgary.[4] Looking at the data historically the 500 MW limit seems to be binding up to 40% of the time.

3. Less than 20% of time point ATC is worse than in the past three years, where ATC is between 500 and 0 MW.
4. About 10% of the time there is zero ATC, compared to about 4% in the past. When we reviewed the increase in outage of the BC to AB transmission line in 2013 of the 712 hours where the ATC was set to 0 MW, 674 hours were due to outages to the 1201L transmission in BC, we understand for maintenance. Pool price across all hours where the BC-AB tie was out averaged $257.23.

At HE 10, Sept 18, 2013, the Montana-Alberta tie line (MATL) turned a new page by becoming commercially operational. The MATL is a 230 kV merchant transmission line connecting the Alberta Interconnected Electric System (AIES) to the Northwestern Energy power grid system in Montana. It is 345 km long, stretching between Great Falls, Montana and Lethbridge, Alberta, with the Canadian portion approximately 123 km. According to public information, the MATL is able to import 295 MW from Montana and export 300 MW from Alberta. In keeping with its responsibility for reliability the AESO did not increase AIES' total import and export capacity. However, MATL does provide energy source diversity within the province and therefore enhance the grid's reliability. With the introduction of the MATL line we understand the AESO is reviewing its present reliability limits of 0 MW on MATL when the BC to AB transmission line is out of service. We look forward to the publication of this study.

[4] One of the following north-south 240 kV lines out of service: 922L, 926L, 190L, 903L, 910L,914L, 906L, 928L, 918L, 932L, 925L, 929L, 901L.

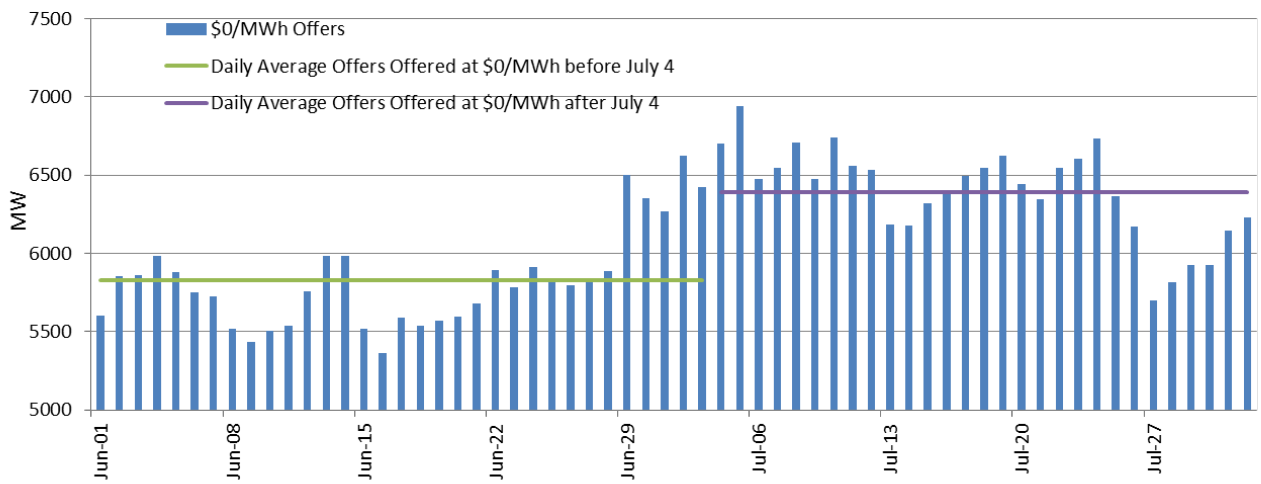
Zero dollar offers of coal generation

On July 7, 2013 from 04:43 to 08:16 the Alberta SMP cleared at $0/MWh. As this was the first instance of a $0 price in Alberta in 2013, the MSA reviewed events on that day to determine the cause. While demand in HE 6 and 7 was the lowest in the month of July it was significantly higher than many hours in May and June where no $0 pool price hours had occurred. The previous Sunday in the same hours demand was of the same order and yet the pool price was $14.39/MWh with roughly 600 MW dispatched above the zero dollar point.

Upon further review as well as being alerted by market participants, the MSA identified that since July 4, 2013 and continuing through the quarter, the coal-fired generating units SD3, SD4, SD5 and SD6 had offered their full available capacity in the energy market at $0/MWh. As a result, the total offers at $0/MWh (zero offers) in the energy merit order increased by almost 600 MW after July 4. An identical offer price change was observed on July 22 for KH2. All five units are owned and operated by the same market participant under Power Purchase Arrangements (PPAs) with three different PPA Buyers authorized to offer into the market the units' Committed Capacity.

The following graph presents the daily average volume of $0/MWh offers of all Alberta-based coal units including the 5 identified units, before and after July 4.

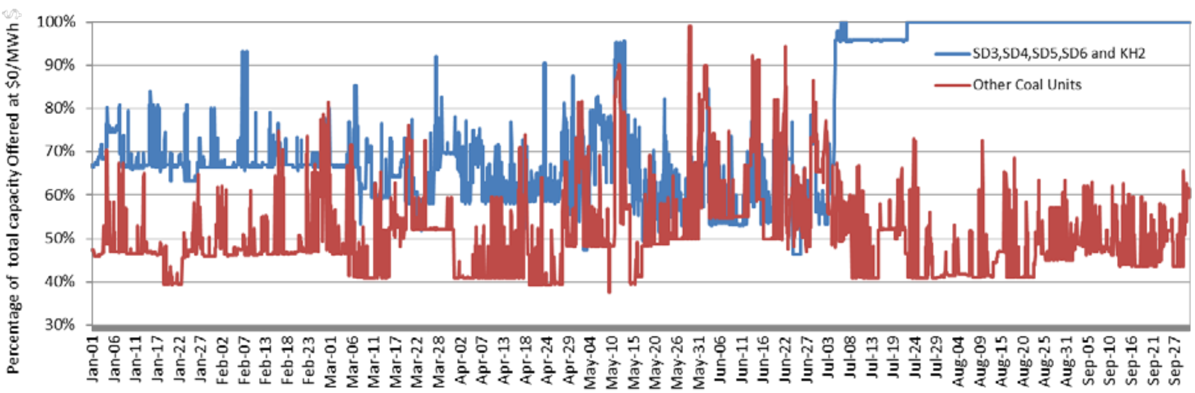
Significantly more $0/MWh offers by all coal units before and after July 4, 2013



The next figure details the dramatic shift in offer prices of SD3, SD4, SD5, SD6 and KH2[5] compared to all other coal-fired generators over the entire quarter. To account for generator outages the data was normalised for each hour using the percentage of the units offered at $0 to their total energy offer.

[5] Since Oct 2, 2013 we have observed from the AESO's CSD page that KH2 and KH1 have become "dispatchable". In other words it would appear that their whole output is no longer offered at $0 at all times.

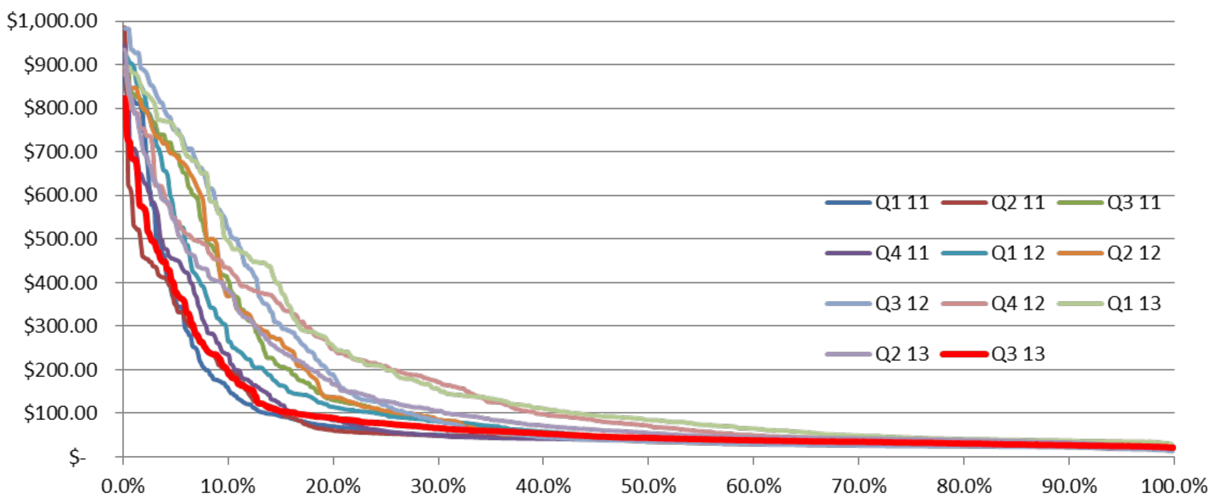
Percentage of all coal units offered at $0/MWh, January – September 2013



The figure also illustrates that the relative volume of other coal units' offers at $0/MWh (shown in red) was lower after July 4.

The MSA also compared pool price duration curves set against different ranges of the supply cushion for each quarter since 2011. The figure below shows the result for the middle segment of the supply cushion.

The Q3 2013 hourly pool price duration curve for the mid-range supply cushion (500 - 1100 MW) shows lower prices compared to most other quarters since 2011



The supply cushion is a measure of the tightness of the market. When the supply cushion is less than 500 MW, scarcity conditions exist and pool prices are normally high. Supply cushion values above about 1100 MW mean that withholding strategies are less effective. We found that there was little remarkable in comparing prices in Q3 2013 with the other quarters for these two segments. However, for the mid-range, between 500 MW and 1100 MW where the MSA has historically observed the largest effects of withholding on pool prices, the price duration curve for Q3 2013 was among the lowest over the eleven quarters reviewed. We attribute the price dampening effects of the shift in $0/MWh offers described above as an important contributing factor to this result.

In the opinion of the MSA the offer price changes described above represent a major structural shift in the nature of supply into the Alberta market. The MSA will continue to work to shed light on the underlying causes. To date, we have no reason to believe that the changes resulted from improper market behaviour by any of the market participants involved.

Closure of Investigations

In the MSA's Q2 report we identified a concern that forward prices for July, August and September 2013 contracts had jumped sharply in advance of it being publicly known that an existing outage of KH1 would be extended. This was viewed as a potential contravention of section 4 of the Fair, Efficient and Open Competition Regulation. The MSA's concern related to large positions taken by a single trader based outside of Alberta. As a consequence we started an investigation and requested records from the unit owner and the trading entity. We have now had an opportunity to review those records along with other relevant information. The records and information available to the MSA do not disclose a breach and therefore we have closed the investigation and notified the parties accordingly.

The MSA also has closed an investigation into traders' access to a competitor's offer information as a result of procedures that had developed over time related to provisions of Power Purchase Arrangements (PPA). The issue is described in a MSA Feedback note released November 7, 2012[6]. The investigation also examined protections against the sharing of competitively sensitive information between parties. The MSA was concerned that the existing procedures in both instances were not consistent with the expectations of section 6 of the Electric Utilities Act.

While the parties in question do not accept that there have been contraventions of any legislative provisions they agreed to take action to address the MSA's concerns. Upon receipt of a Mitigation Plan the MSA forbore any further action and closed the investigation. The MSA chose an alternative case resolution because the parties self-reported the factual circumstances, fully cooperated during the investigation and, as stated, endorsed a Mitigation Plan at senior levels of the companies that addressed improved compliance policies, programs and training.

During the investigation, the MSA and a representative of one of the parties raised with the AESO the importance of changes to the ETS inputs so that the sharing of offers on PPA units or jointly owned generators is no longer required. We understand the AESO is now considering how best to make changes to the ETS.

While investigations perhaps leading to proceedings in front of the AUC are one method of promoting fair, efficient and open competition, market participants' willingness to take on board MSA concerns and unilaterally change behaviour can be an equally effective resolution and one that "minimizes the cost of regulation" in the words of subsection 5(h) of the EUA. In this matter, an additional benefit is that now all PPA Buyers have undertaken action to limit traders' access to competitively sensitive information.

[6] Excess Energy / Increased Capacity Offers of PPA Units
http://albertamsa.ca/uploads/pdf/Archive/2012/MSA%20Feedback%20-%20PPA%20Excess%20Energy%20121107.pdf

Retail market

Preliminary Assessment of the Feasibility of all Regulated Rate Option Procurement through Auctions

Recommendation #40 of the Retail Market Review Committee's report, "Power for the People", stated that all Regulated Rate Option (RRO) procurement by the three main providers should be undertaken using auctions in the same manner as EPCOR. This analysis reviews the EPCOR auction process.

EPCOR's Energy Price Setting Plan (EPSP) differs from those of ENMAX and Direct in that it uses an auction approach to procure energy for its RRO customers. EPCOR provides RRO service to the City of Edmonton and customers in the Fortis Alberta area. We undertook an analysis of the EPCOR RRO auctions over the period July 2011 to June 2013. Note that in this period EPCOR conducted its buying within the 45-day period prior to the month of delivery. EPCOR's EPSP has since been amended to allow buying over a 120-day window per the revised RRO Regulation. EPCOR's informal assessment is that the auctions appear to performing satisfactorily with the longer buying window. The data in this analysis was based on the 45-day model.

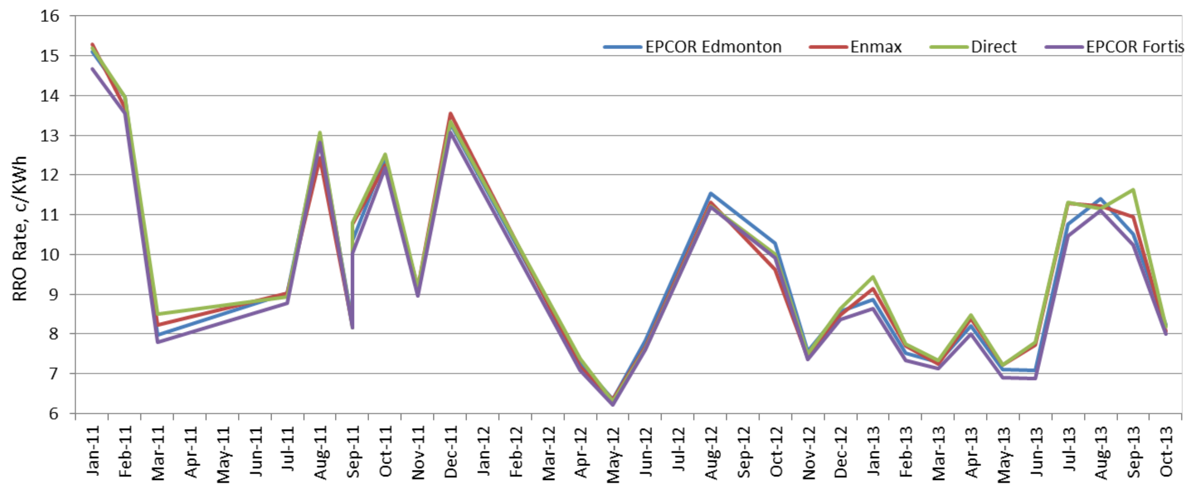
Description of the Auction Process

Prior to the month of delivery, EPCOR prepares a load forecast for the applicable month and then estimates the number of blocks of Flat (7 X 24) and Extended Peak (7 X 16) energy that approximates the shape of the load forecast. This energy is then bought over a series of power auctions that are conducted on the Natural Gas Exchange (NGX). Normally three rounds of auctions for each product are sufficient to secure the necessary energy. A fourth (contingency) auction is available in the event that three rounds are not enough. EPCOR has available a (confidential) back-stop provision in the event that the contingency auction fails to yield sufficient energy to meet EPCOR's needs. The back-stop provision has not yet ever been exercised.

The pay-as-bid auctions were held through the NGX Power Auction System. The block size for each auction was standardized at 25 MW for Flat and 10 MW for Extended Peak. At the beginning of an auction, a seed price was posted and every supplier observed it on NGX screen. The seed price is set via a formula and acts as a price cap for the particular auction. Suppliers were anonymous, though each supplier knew the total blocks offered at an auction and their associated prices. Suppliers could modify their offers (including withdrawal) until the closing period began. The closing period lasted for two minutes, and suppliers could only stay pat or reduce their offer prices during this period. Following the two minute closing period is a random closing period, during which suppliers can only stay pat or reduce their offer prices. As its name suggests, the random closing period had a random duration. Various parameters are used to determine if the auction is to be deemed 'competitive' and how much is procured – the key here is that EPCOR has no discretion in these matters.

In our Q1/13 report, we looked at the average block prices paid by EPCOR and found that there was no material difference from the prices paid by ENMAX and Direct. Final prices to customers are closely grouped as shown in the following figure despite the differences among the approaches.

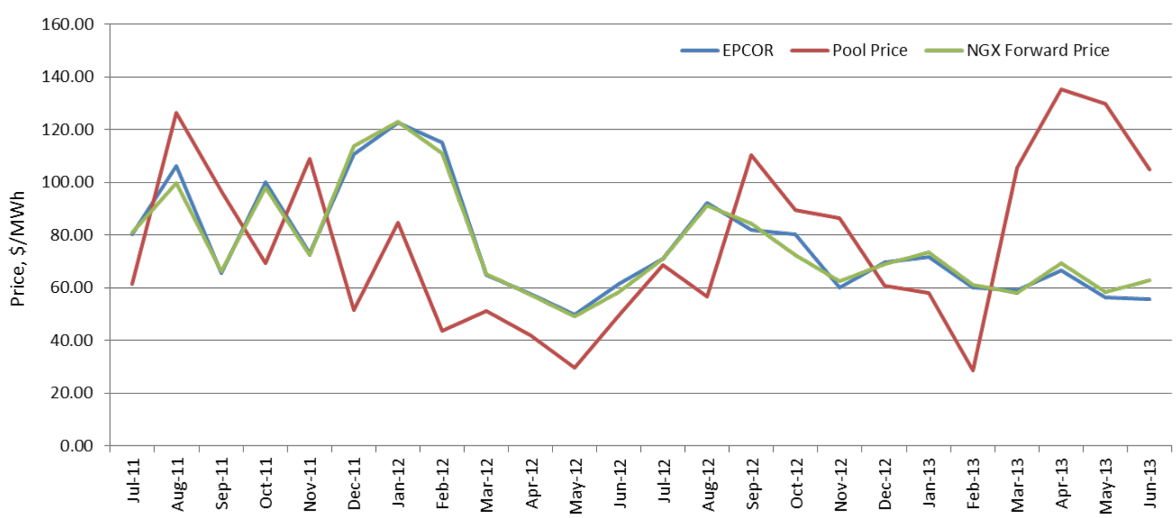
Comparison of Regulated Rate Option Prices to Customers



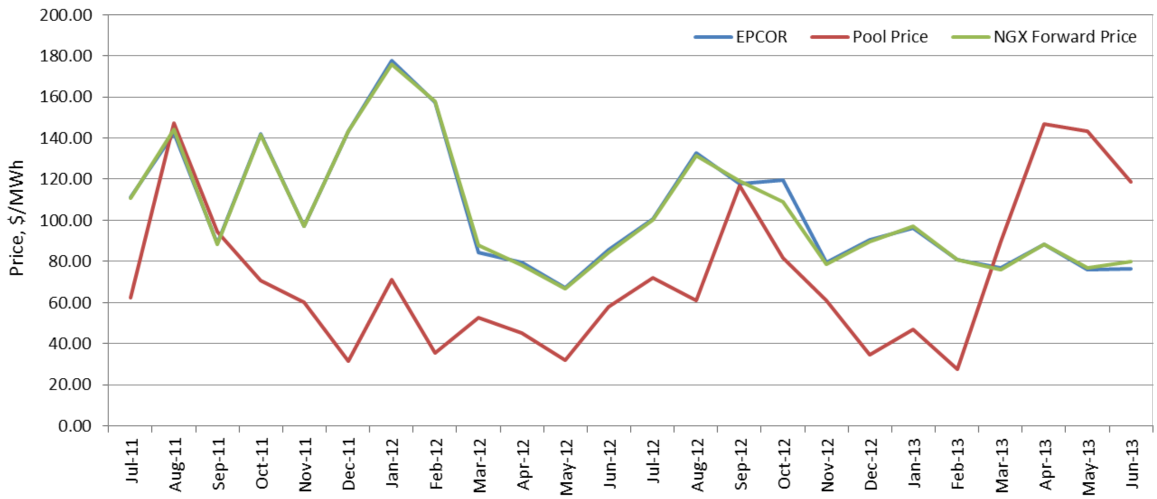
All trades on NGX in the 45-day window, including EPCOR's auction purchases, are used to calculate an index price, one for Flat and one for Extended Peak. Next two figures show the prices paid by EPCOR compared with this index. It is apparent that there is a very close correspondence between them. This suggests that EPCOR is paying the market price.

These two figures also show the corresponding monthly average pool prices. For both Flat and Extended Peak contracts, there is a very poor correspondence between the EPCOR price or the NGX index and the relevant pool prices. Also, for the Extended Peak there appears to be a premium paid to acquire the volume. That is not so apparent in the Flat product. This may relate to the relative lower liquidity of the Extended Peak product compared with the Flat.

Comparison of Procurement Price, Pool Price and Forward Market Price - Flat

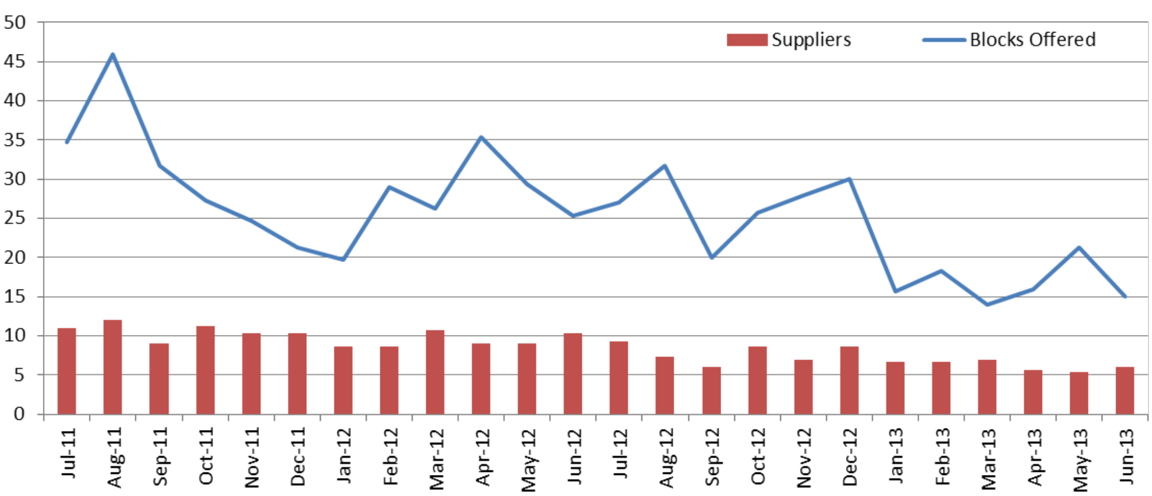


Comparison of Procurement Price, Pool Price and Forward Market Price – Extended Peak

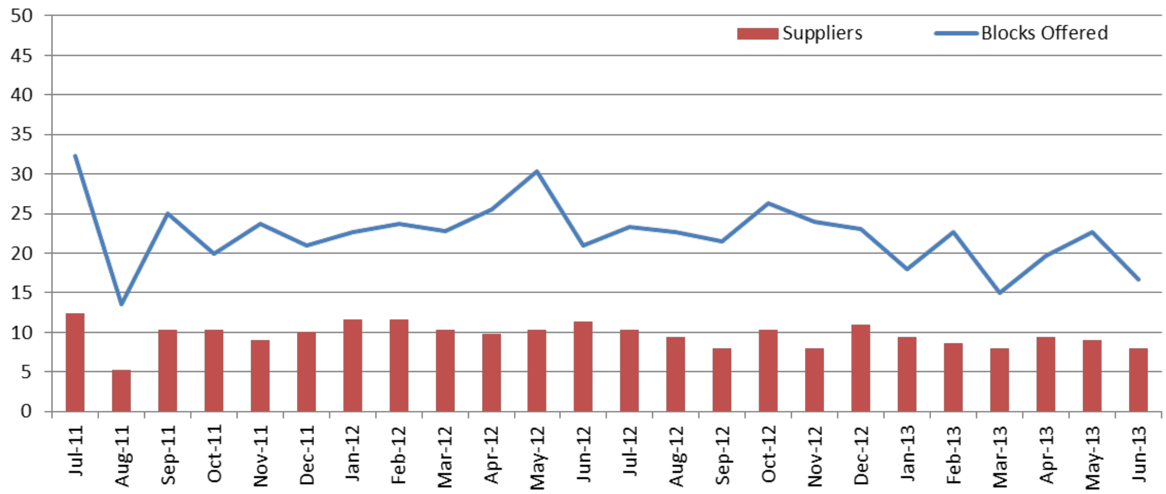


Competitiveness among the sellers is critical to the success of the auctions. The next two figures plot the average number of suppliers and blocks offered over the auctions for each month. The average number of sellers has reduced somewhat since mid-2011 as has the average number of blocks.

Blocks Offered and Suppliers Participated at Each Auction - Flat

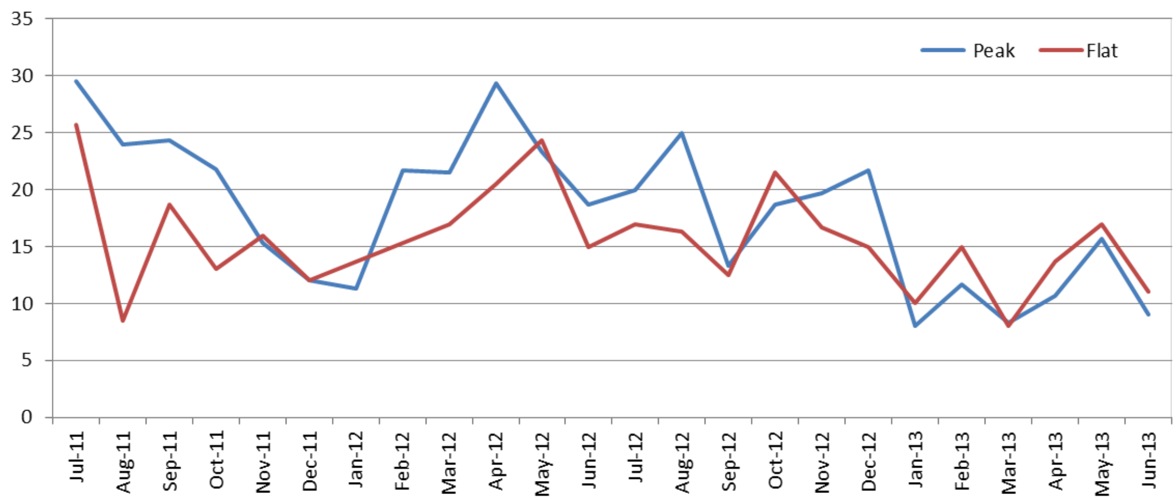


Blocks Offered and Suppliers Participated at Each Auction – Extended Peak



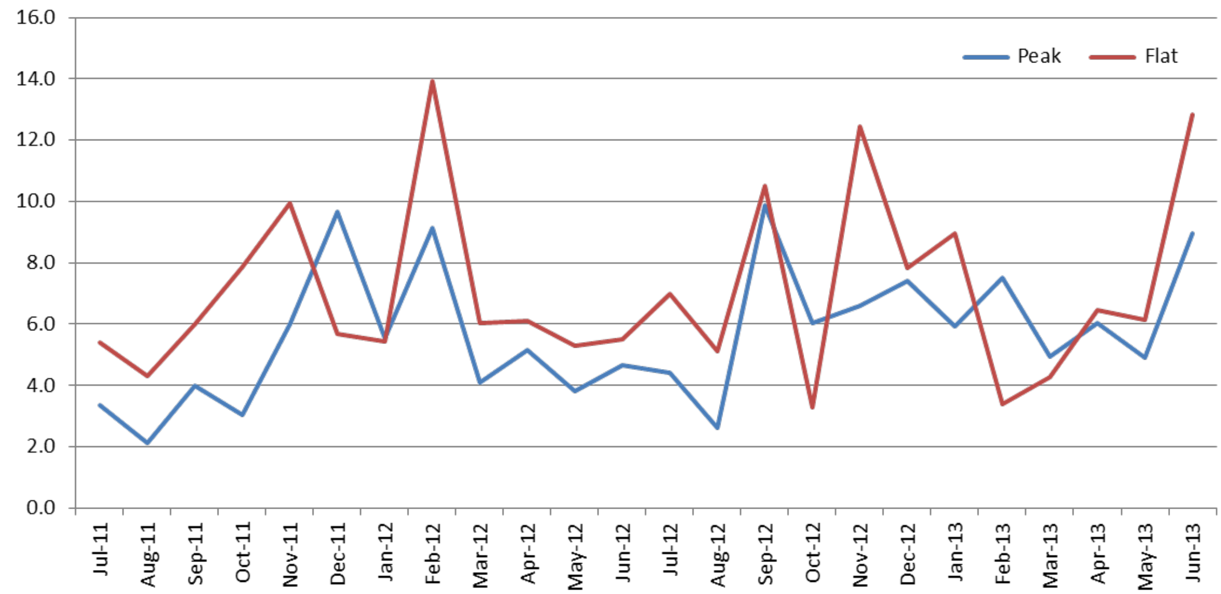
The next figure shows the average number of blocks offered but not sold at each auction grouped by product month. A reducing trend is apparent starting in 2013 for both contracts. The impact of this trend on EPCOR's RRO procurement prices is not yet known but we know from the first figure that the prices remain in line with those of the other RRO buyers.

Blocks Offered but not sold at Each Auction



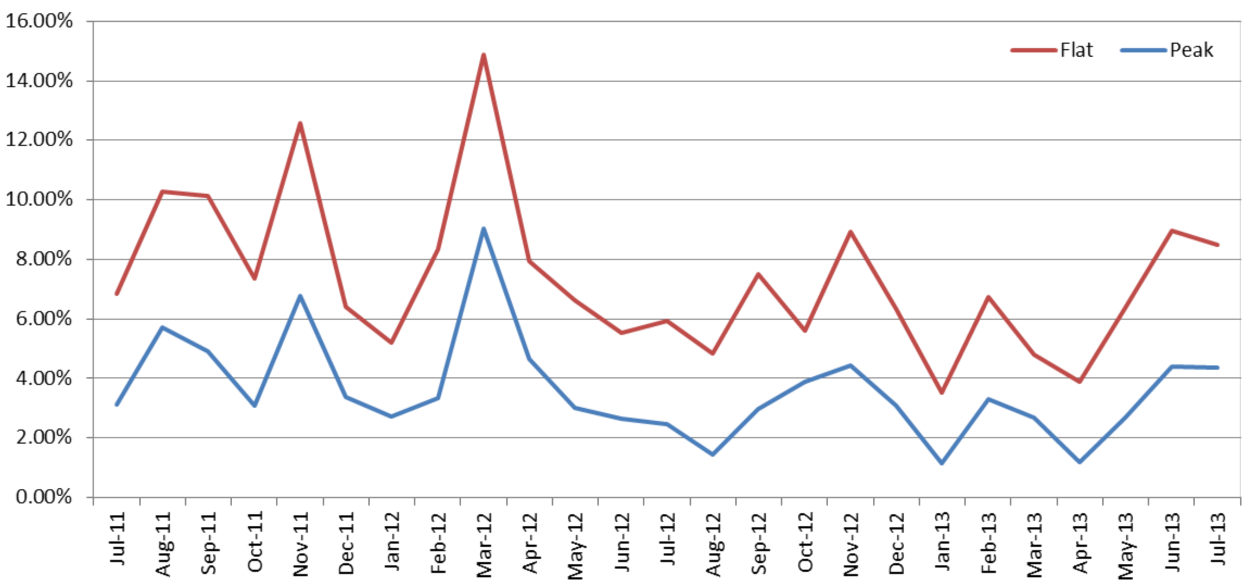
Price cutting should be observed frequently in a competitive 'pay as bid' auction process. The next figure presents how many times a participant reduces its block bid price to undercut its competitors at each auction grouped by product month. Price cutting is more frequent for the Flat contracts than the Extended Peak contracts - the auctions for Flat contracts appear to be more competitive.

How Often to Undercut - Number of Undercuts per Block per Auction



The next figure complements the one above by presenting the average percentage of price reduction for each block (price reduction divided by final procurement price). The price reduction is the price difference between the highest and final offer price of a block in an auction. Consistent with the latest figure, the price undercutting in percentage amount is more aggressive for Flat contracts than Extended Peak contracts.

How Much to Undercut - Percentage of Price Reduction per Block per Auction



Summary

The assessment of the EPCOR auctions has not revealed any significant issues in terms of performance. In considering extending all buying for the RRO via EPCOR-style auctions, the following points are noted:

- EPCOR buys about 60% of the total RRO load and hence the addition of Direct and ENMAX would increase the total buying by about two-thirds;
- Direct and ENMAX are already buying their RRO volumes primarily through NGX, but spread out more evenly over the whole buying period – this is not new buying, just a different timing; and,
- Another of the recommendations from "Power for the People" would reduce the RRO eligibility threshold and hence overall RRO volume substantially, depending on the final decision that is implemented.

The foregoing suggests that there should be no significant problems focusing the buying into EPCOR-type auctions.

The more frequent buying by Direct and ENMAX in their current EPSPs serves to enhance forward market liquidity and to assist in the determination of auction seed prices for EPCOR – a feature that would be impaired with all RRO buying concentrated into auctions. This may mean that some fine tuning of the auction seed price-setting mechanism may be required but that should not be an insurmountable obstacle.

AS market

Rate of Return in the Operating Reserve Market

Some market observers have commented on the seemingly high cost of operating reserves in Alberta. This section analyzes the rate of return in the operating reserve market. The rate of return is given by the total revenue less the total operational cost of providing reserves, which includes fixed and variable O&M cost, expressed as a percentage of the fixed cost of investment. This is basically a net revenue analysis similar to those the MSA has undertaken in previous quarterly reports except that the analysis compares revenues from selling different products: energy and operating reserves.

The analysis assumes the cost structure of a LM 6000 gas combustion turbine with capacity 47 MW. The analysis includes the active operating reserve payment revenues and the energy payments associated with the energy output from providing operating reserves, which are calculated based on historical data from 2008 to 2012. To simplify the analysis, the generator will participate in one market (either regulating reserve (RR), or spinning reserve (SR), or supplemental reserve (SUPR)) only, and not participate in the super peak or OTC markets to provide other services.

	Assumptions	
Capacity (MW)	47	
Heat Rate (GJ/MWh)	10	
Fixed Cost ($/kW)	1000	
Fixed O&M ($/kW-year)	57	
Variable O&M ($/MWh)	0.55	
Outage Rate (%)	10	
	RR	Contingency Reserves
Capacity Factor (%)	50	1

To determine if there is an arbitrage opportunity, the rate of return from energy market participation is also included. In the energy market, it is assumed that the generator will only provide energy if the pool price is greater than its marginal fuel plus variable O&M costs. The capacity factor is assumed at 50% when providing regulating reserve and 1% for contingency reserves. The outage rate is assumed to be 10%. These and other assumptions are listed in the right table.

The estimated rate of return is listed in the next table. The results show that there is minimal arbitrage advantage among the contingency reserve markets and the energy market, suggesting efficiency across the energy and contingency reserve markets. The return for participation in the regulating reserve market has been consistently higher than the returns from the other three markets. However, the analysis did not include the cost of an AGC device which would increase capital costs and perhaps the operating costs of providing regulating reserves. If this is not a significant factor, the results suggest that the regulating reserves market is less competitive than the contingency reserves and the energy market.

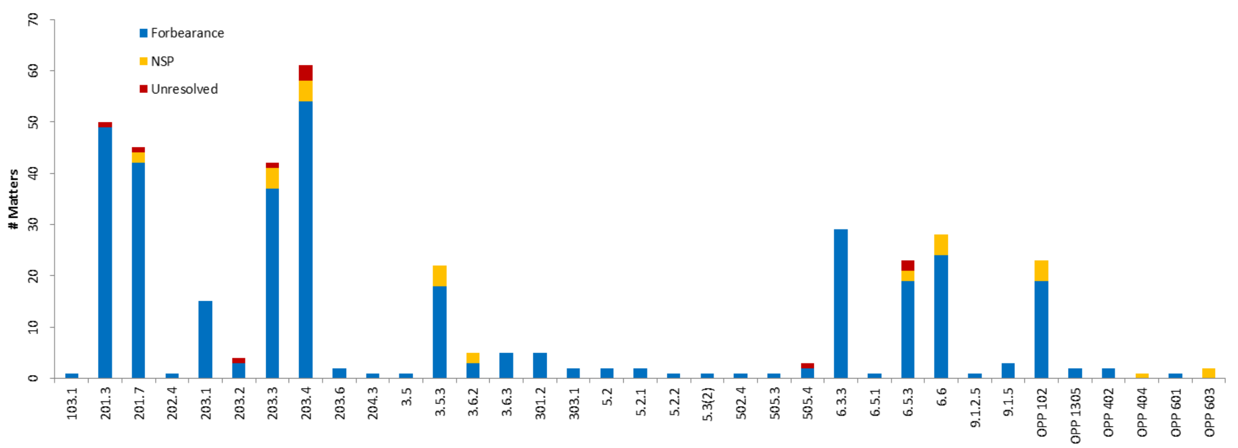
Estimated Rate of Return for a 47 MW Gas Unit

Year	RR	SR	SUP	Energy
2008	67%	27%	23%	21%
2009	14%	7%	3%	7%
2010	19%	11%	7%	10%
2011	50%	37%	32%	33%
2012	46%	34%	29%	31%

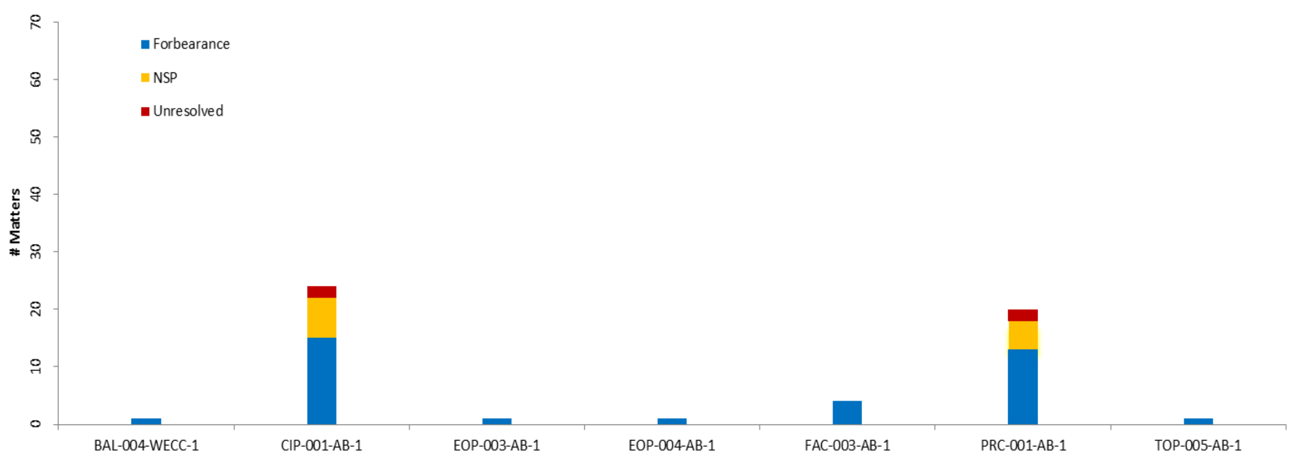
Compliance

- The inventory to unresolved files at the end of Q3/13 remained at a reasonable level of 10 ISO rules files and 5 reliability standards files.
- Year to date, the MSA opened 331 files relating to ISO rules compliance vs. 318 for the same period a year ago however, of the files opened in 2013, 50 related to the new ISO rule 201.3 (Offer Control Information). Of those 50 files, only 2 were opened in Q3/13.
- Year to date, the MSA has issued 29 notices of specified penalty with respect to ISO rules compliance matters as compared to 42 during the same period last year.
- Year to date, the MSA has issued 9 notices of specified penalty with respect to reliability standards matters as compared to 3 during the same period a year ago. PRC-001-AB-1 and CIP-001-AB-1 are the subject of all 9 NSPs issued year to date resulting from their broad applicability.

ISO Rules Compliance, 2013 year to date



Alberta Reliability Standards Compliance, 2013 year to date



MSA activities and releases

Market reporting

MSA 2013 Second Quarter Report (07/31/13)

Feedback

Feedback - URICA's Service Agreement with the UCA (08/14/13)

Feedback – Sale of Genesee PPA (09/11/13)

Consultations

Notice re Stakeholder Meeting - Agenda Details (09/26/13)

Notice re Stakeholder Meeting - Looking Back and Looking Forward (09/18/13)

Notice re Additional Stakeholder Comment Regarding Framework for the Assessment of Market Harm Strawdog (09/17/13)

Notice re Stakeholder Comments Regarding Framework for the Assessment of Market Harm Strawdog (09/16/13)

Notice re Framework for the Assessment of Market Harm: Further Extension of Deadline for Comments (09/03/13)

Notice re Framework for the Assessment of Market Harm: Extension of Deadline for Comments (08/16/13)

Notice re MSA Stakeholder Meeting (08/15/13)

Notice re HTR Response, Decision and Recommendation (08/07/13)

Notice re Framework for the Assessment of Market Harm (07/31/13)

Other

Forbearance Letter re AESO Compliance per ISO Rule Section 203.6 (09/26/13)

Forbearance letter re Total Export Transfer Capability Positions (08/01/13)

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.